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August 12, 2021

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

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI or the Company)

Application for Common Rates and 2022 Revenue Requirements for the Fort Nelson Service Area (Application)

Attached, please find FEI's Application for Common Rates and 2022 Revenue Requirements for the Fort Nelson Service Area.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners to the FEI Fort Nelson 2019-2020 RRA

FORTISBC ENERGY INC.
FORT NELSON SERVICE AREA

Common Rates and 2022 Revenue Requirement Application

August 12, 2021

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1. EXECUTIVE SUMMARY

FortisBC Energy Inc. (FEI or the Company) files this Fort Nelson Common Rates and 2022 Revenue Requirement Application (Application) with the British Columbia Utilities Commission (BCUC) pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA):

- to implement common delivery and cost of gas rates (Proposed Common Rate Option) with FEI for the Fort Nelson service area (FEFN) effective January 1, 2023; and
- to set the delivery rates and the Revenue Stabilization Adjustment Mechanism (RSAM) rate rider for FEFN effective January 1, 2022.

Implementing common delivery and cost of gas rates will provide long-term benefits to Fort Nelson customers, reduce regulatory costs and burden, and achieve greater fairness and consistency of rate treatment across FEI's service areas.

As discussed in Section 3 of the Application, over the past decades, FEI has aligned natural gas rates and services across the Province through amalgamation and implementation of common rates across its service territories. At this time, FEI's Fort Nelson service area, with its customer base of approximately 2,400 customers, is the only outlier, maintaining a separate rate base and rates.

In Section 4 of the Application, FEI discusses FEFN's regulatory, financial and operational context, including the impact that factors such as declining demand and changes in the customer mix have had on FEFN rates historically, and the impact that such factors may continue to have on rates in the future. Due to FEFN's small customer base, FEFN has historically experienced much greater delivery rate volatility and, on average, larger delivery rate increases than FEI. By maintaining a separate rate base, the costs of local infrastructure projects such as the Muskwa River Crossing Project and the costs of ongoing maintenance programs such as the mains renewal program are fully absorbed by FEFN customers only, which can result in large annual delivery rate increases. The BCUC also noted the magnitude of FEFN delivery rate increases and the continuing downward trend of total energy demand in its decision on the FEFN 2019-2020 Revenue Requirements Application (2019-2020 RRA Decision).[1] It is in this context, along with consideration of the rate design principles identified by Dr. Bonbright and the general support for common, or postage stamp, rates from the Government and in past BCUC decisions, as well as feedback received through FEI's engagement with Indigenous groups and stakeholders, that FEI developed the Proposed Common Rate Option.

FEI examined a number of common rates options, which are described in detail in Section 5. These options include implementing common rates for all rate components (i.e., delivery, cost of gas, and storage and transportation), partial implementation of common rates (i.e., either

[1] Appendix A to Order G-48-19, p. 10.

delivery and cost of gas, or delivery only), and maintaining the status quo. FEI assessed these options against four key objectives (Objectives):

1. Eliminate the regulatory cost and burden associated with preparing and reviewing the separate regulatory filings required for FEFN, including the cost and time related to the public hearing processes;
2. Provide long-term rate stability for FEFN customers;
3. Achieve fairness across all FEI service areas by aligning FEFN rates with the rest of FEI's service areas; and
4. Mitigate any significant rate increases for FEFN customers that may result from the adoption of common rates.

FEI also examined various implementation approaches based on the rate impact associated with moving to common rates for each rate class.

As FEI demonstrates in Section 5, the option that best achieves the Objectives is to implement common delivery and cost of gas rates while maintaining FEFN's midstream rate at a level consistent with what FEFN is currently being charged, and to phase in the common delivery rate component for residential customers in order to mitigate the initial rate pressures (Proposed Common Rate Option).

FEI has engaged with Indigenous groups and stakeholders in the preparation of the Application. On April 27, 2021, FEI held a virtual town hall to explain the Company's plans to file a common rates application, including the options being considered and the potential rate impacts of certain options. The town hall was well attended and FEI had the opportunity to respond to a number of questions during the live question and answer session as well as in follow-up emails to some participants. Attendees were also invited to respond to a survey which asked questions related to common rates options and sought feedback on additional information that would be useful to provide to stakeholders either through direct contact or through incorporation of the information into the Application. Subsequent to the virtual town hall, FEI also presented its common rates proposals to the Fort Nelson First Nation Council and to the Council for the Fort Nelson Northern Rockies Regional Municipality. FEI took the feedback it received into account in preparing this Application and selecting the Proposed Common Rate Option. The details of FEI's Indigenous and stakeholder consultation are provided in Section 6.

Details of the implementation of the Proposed Common Rate Option, including the required changes to FEI's financial schedules and proposed tariff changes, are discussed in Section 7. In this section, FEI also seeks approval to dispose of the FEFN Revenue Surplus deferral account approved by Order G-78-21 to help mitigate the rate increase for FEFN residential customers resulting from the move to common rates.

In Section 8, FEI sets out the 2022 revenue requirements and rates for FEFN and requests approval of an effective delivery rate increase of 3.41 percent and approval to set the RSAM rate rider at a credit of $0.416 per gigajoule (GJ), both effective January 1, 2022. Given that FEI expects that permanent delivery rates will not be approved prior to the beginning of 2022, FEFN is seeking approval of the delivery rate changes on an interim, refundable basis, effective January 1, 2022. The proposed delivery rate increase and other approvals sought in Section 8 are required to ensure that the Company's rates recover the costs of serving FEFN customers in 2022, which, if the Proposed Common Rate Option is approved, will be the last year that rates are set separately for FEFN.

FEI has determined that 2023 is the appropriate time to transition FEFN customers to common rates. The Proposed Common Rate Option will benefit all FEFN customers in the long-term and will provide immediate rate relief to commercial customers. Additionally, implementing the Proposed Common Rate Option will eliminate the regulatory cost and effort associated with preparing and reviewing the separate regulatory filings required for FEFN, including the costs and time related to the public hearing processes, and the Proposed Common Rate Option achieves greater fairness and consistency amongst FEI's customers.

2. APPROVALS SOUGHT, PROPOSED REGULATORY PROCESS AND ORGANIZATION OF THE APPLICATION

2.1 *APPROVAL SOUGHT*

FEI seeks the following approvals from the BCUC, pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA):

- Approval to recover the 2022 revenue requirement, as set out in Section 8 of the Application, through an effective delivery rate increase of 3.41 percent, on a permanent basis, effective January 1, 2022.
- Approval to set the RSAM rate rider at a credit of $0.416 per GJ, as set out in Section 8.2, Table 8-2, effective January 1, 2022.
- Adoption of the following common accounting policies for FEFN which were approved for FEI by Order G-165-20:
  - Capitalized overhead rate of 16 percent;
  - Depreciation and net salvage rates as set out in FEI's most recently approved depreciation study; and
  - Modification to the lead/lag days, as set out in FEI's most recently approved lead/lag study, for calculation of FEFN's cash working capital.
- Amalgamation of FEFN's gas supply portfolio costs with FEI's Midstream Cost Reconciliation Account (MCRA) as follows:
  - Transfer the closing December 31, 2022 balance of FEFN's Gas Cost Reconciliation Account (GCRA) to FEI's MCRA as an opening balance adjustment, effective January 1, 2023;
  - Eliminate FEFN's GCRA;
  - Starting January 1, 2023, capture all of FEFN's natural gas supply portfolio costs, including FEFN's transportation costs, in FEI's MCRA;
  - Starting January 1, 2023, charge FEFN customers the same cost of gas rate as FEI customers, with the recoveries of the cost of gas rate from FEFN's customers captured in FEI's MCRA; and
  - Starting January 1, 2023, set FEFN's midstream rates[2] based on 5 percent of FEI's midstream rates.
- Implementation of common delivery rates for FEFN with FEI, effective January 1, 2023:
  - Approval to transfer the closing December 31, 2022 balances of FEFN's gross plant in service, accumulated depreciation, contributions in aid of construction

[2] Midstream rates include the Storage and Transport Charge per GJ and the MCRA Rate Rider 6 per GJ.

(CIAC), and accumulated amortization of CIAC to FEI's corresponding plant accounts and include these amounts in FEI's rate base as January 1, 2023 opening balance adjustments;

- Approval of the treatment of each of FEFN's deferral accounts as described in Table 7-1 in Section 7.1.4.1 and Section 7.1.4.2;
- Approval to transfer FEFN's capital work in progress (no AFUDC) and unamortized deferred charges to FEI's rate base under the same categories;
- Approval to include FEFN's operations and maintenance (O&M) expenses in FEI's formula O&M effective January 1, 2023 by adding FEFN's forecast 2023 customer count to FEI's forecast 2023 customer count, with these changes to be forecast in FEI's Annual Review for 2023 Delivery Rates;
- Approval to incorporate FEFN's annual forecast capital expenditures into FEI's regular forecast capital expenditures commencing January 1, 2023, with these changes to be forecast in FEI's Annual Review for 2023 Delivery Rates;
- Approval of certain amendments to the FEI Tariff Rate Schedules, effective January 1, 2023, including the proposed FEFN rate schedule mapping to the applicable FEI rate schedules, as set out in Appendix D and described in Section 7.1.5;
- Approval of the cancellation of the FEFN Gas Tariff, effective January 1, 2023, including the FEFN rate schedules and rates, as described in Section 7.1.5;
- Approval to phase in common delivery rates for the FEFN residential customer rate class (Rate Schedule 1) over 10 years through the creation of a Residential Customer Phase-in Rate Rider, effective January 1, 2023, to mitigate the initial delivery rate impact to FEFN residential customers resulting from common rates with FEI, as described in Sections 5.5 and 7.1.4.4. The approval of the phase-in rate rider is comprised of:
    - Setting the phase-in rate rider by phasing in the initial delivery rate impact to FEFN residential customers over 10 years and phasing in the approved 2021 FEFN revenue surplus, with a forecast credit balance of $94 thousand at December 31, 2022, over 10 years;
    - Renaming the existing FEFN 2021 Revenue Surplus deferral account to the FEFN Residential Common Rate Phase-in deferral account, and using this deferral account for the purposes of phasing in common delivery rates for FEFN residential customers;
    - Setting the actual phase-in rate rider each year in FEI's annual reviews based on updated forecasts of FEFN's residential customer demand and the balance of the deferral account each year for the 10-year period.

- Creation of a new rate base deferral account – the FEFN Common Rates and 2022 Revenue Requirement Application Costs deferral account – to capture the regulatory costs associated with this Application and corresponding regulatory process.

2.2 PROPOSED REGULATORY PROCESS AND INTERIM 2022 DELIVERY RATES

FEI submits that a written hearing process is appropriate for the review of this Application. FEI also submits that it is most efficient from a regulatory standpoint to proceed to an earlier decision on the 2022 revenue requirement and delivery rate proposals (Section 8 of the Application) by concluding that process after one round of information requests (IRs) and written arguments, and proceeding with further review of the common rate proposals thereafter.

FEI has provided detailed information supporting its proposed delivery rate increase for FEFN for 2022 in Section 8 of the Application. FEI considers that one round of IRs followed by written arguments is sufficient to fully examine FEI's proposals regarding FEFN's 2022 delivery rates. Given the greater level of complexity and content associated with the common rates component of the Application, FEI considers two rounds of IRs followed by written arguments is reasonable and is consistent with regulatory processes established for similar types of applications.

Accordingly, FEI proposes the following regulatory timetable:

Table 2-1: Proposed Regulatory Timetable

ACTION	DATE (2021)
BCUC Issues Procedural Order	Week of August 30, 2021
FEI Publishes Notice by	Week of September 13, 2021
Intervener Registration	Thursday, September 30, 2021
BCUC Information Request (IR) No. 1 on 2022 Delivery Rates and Common Rates	Thursday, October 7, 2021
Intervener IR No. 1 on 2022 Delivery Rates and Common Rates	Friday, October 15, 2021
FEI Response to IR No. 1 on 2022 Delivery Rates and Common Rates	Friday, November 5, 2021
Commencement of Separate Review Streams for the 2022 Delivery Rate Component and the Common Rates Component	
FEI Final Argument on 2022 Delivery Rates	Monday, November 15, 2021
Intervener Final Argument on 2022 Delivery Rates	Monday, November 29, 2021
BCUC and Intervener IR No. 2 on Common Rates	Wednesday, December 1, 2021
FEI Reply Argument on 2022 Delivery Rates	Monday, December 13, 2021
FEI Response to IR No. 2 on Common Rates	Wednesday, December 22, 2021

ACTION	DATE (2022)
FEI Final Argument on Common Rates	Friday, January 7, 2022
Intervener Final Argument on Common Rates	Friday, January 21, 2022
FEI Reply Argument on Common Rates	Friday, February 4, 2022

Given the proposed timetable set out in Table 2-1 above, FEI does not anticipate receiving a decision on 2022 delivery rates prior to January 1, 2022. Therefore, FEI requests approval pursuant to sections 59 to 61 and 89 of the UCA of an interim and refundable 2022 effective delivery rate increase of 3.41 percent and approval to set the RSAM rider at a credit of $0.416 per GJ, as described in Section 8, effective January 1, 2022. FEI has included the interim 2022 delivery rate increase and change to the RSAM rider approvals as part of the draft procedural Order provided in Appendix F1. FEI has also included a draft form of Order sought for the final approval of the 2022 delivery rate increase in Appendix F2 and for the final approval of FEFN common rates with FEI in Appendix F3.

2.3 *ORGANIZATION OF THE APPLICATION*

The remainder of this Application is organized as follows:

- **Section 3** – History of FEI and FEFN and the Evolution of Common Rates – outlines the corporate and regulatory history of FEI and provides details on the rationale for the evolution of common rates across FEI's services areas;
- **Section 4** – Regulatory, Financial and Operational Context of FEFN, and Government Policy Supporting Common Rates – provides the overarching considerations that were taken into account when developing the Application proposals, including key historical regulatory developments in Fort Nelson, the financial and operational environment in Fort Nelson, and government policy related to common, or postage stamp, rates;
- **Section 5** – Review of Common Rate Options – describes the four objectives with which FEI assessed the common rate options and provides a qualitative and quantitative assessment of each common rate option;
- **Section 6** – Indigenous and Stakeholder Consultation – explains how FEI's Communication and Consultation Plan addresses Indigenous engagement and stakeholder consultation, and demonstrates that FEI has undertaken and will continue to undertake appropriate engagement with Indigenous and stakeholder groups;
- **Section 7** – Implementation and Accounting Matters – describes the process for implementing the Proposed Common Rate Option, including the mitigation of rate impacts to residential customers through phasing in of changes and utilization of the existing balance in the 2021 Revenue Surplus deferral account;

- **Section 8** – 2022 Delivery Rates – provides the 2022 revenue requirement and delivery rates for the standalone FEFN service area and requests approval to increase delivery rates and to set FEFN's RSAM rate rider effective January 1, 2022, as well as other approvals related to the 2022 revenue requirement; and
- **Section 9** – Conclusion.

3. HISTORY OF FEI AND FEFN AND THE EVOLUTION OF COMMON RATES

3.1 *INTRODUCTION*

This section outlines the corporate and regulatory history of FEI, including when Fort Nelson was acquired by the Company and why it has historically maintained a separate rate base and rates. As discussed below, over the years FEI has been bringing its service areas together under one entity both legally and with regard to common rates. FEFN is the last remaining service area which has a separate rate base and rates.

3.2 *FEI'S CURRENT CORPORATE AND OPERATING STRUCTURE*

FEI is one of the largest natural gas distribution companies in Canada, based on number of customers and service area. FEI provides sales and transportation services to residential, commercial and industrial customers in approximately 135 communities, currently serving more than one million customers throughout the Province. FEI owns and operates natural gas pipelines and natural gas distribution facilities in BC, including approximately 50,200 km of transmission pipelines and distribution mains. FEI's distribution network serves approximately 95 percent of natural gas customers in BC. FEI, through its parent company FortisBC Holdings Inc., is a wholly owned subsidiary of Fortis Inc., a leader in the North American regulated electric and gas utility industry.

FEI is comprised of two service areas: Mainland and Vancouver Island[3] is one service area; and Fort Nelson is the other. Although not a separate legal entity, Fort Nelson has historically had its own rate base for the purposes of determining rates. Therefore, FEI currently has two rate bases: one for the Fort Nelson service area and one for the Mainland and Vancouver Island service area. FEI's operations in FEFN consist of a transmission lateral from the nearby Spectra Energy processing plant to the town of Fort Nelson, together with a gas distribution system.

3.3 *FEI'S CORPORATE HISTORY AND THE EVOLUTION OF COMMON RATES*

Over the years, FEI has brought what was previously six service areas together under one entity, both legally and with regard to common rates. FEFN is the last remaining service area which has a separate rate base and rates.

[3] Mainland and Vancouver Island includes what was previously referred to as the Inland, Columbia, Vancouver Island and Whistler regions.

3.3.1 Corporate History

FortisBC Energy Inc. (FEI)[4] is a company incorporated under the laws of the Province of British Columbia (BC or Province) with almost 60 years of history in the natural gas business offering a reliable supply of natural gas, delivered safely and efficiently at a reasonable cost.

The Company began distribution and transmission of natural gas in BC in the 1950s. In 1952, Inland Natural Gas Co. Ltd. (Inland) was incorporated to distribute natural gas throughout the BC interior. In the 1950s, Inland purchased several subsidiaries, including St. John Oil and Gas, Peace River Transmission, Canadian Northern Oil and Gas, and Grand Prairie Transmission. In 1977, Inland purchased Columbia Natural Gas in the East Kootenays, which positioned Inland as the major distributor of natural gas for most of the BC Interior. In 1985, Inland acquired Fort Nelson Gas Ltd., the owner of the gas distribution system in and around Fort Nelson, from Colonial Oil and Gas Limited and in 1987, Inland purchased Squamish Gas Co. Ltd. from Superior Propane Ltd. In 1988, through a holding company named BC Gas Inc., Inland purchased the Lower Mainland gas division of British Columbia Hydro and Power Authority (BC Hydro). In 1989, Inland was amalgamated with BC Gas Inc., Columbia Natural Gas Limited, and Fort Nelson Gas Ltd. under the name BC Gas Inc. and became the fourth largest gas distribution utility in Canada.

In 1990, BC Gas commenced construction, operation and maintenance of a satellite, off-grid piped propane distribution system that today serves approximately 1,500 residential and commercial customers in Revelstoke. The propane is supplied to Revelstoke by railcars and tanker trucks, where it is offloaded into storage tanks, vaporized as needed, and distributed to customers through an underground piped distribution system. The costs of the Revelstoke distribution system were included in FEI's rate base and delivery rates at that time, and continue to have this treatment. As will be described later in this Application, the BCUC approved common commodity rates for Revelstoke customers in October 2020.[5]

In 1993, restructuring caused BC Gas Inc. to change its name to BC Gas Utility Ltd. and a holding company that held all the shares of BC Gas Utility Ltd. was named BC Gas Inc. A subsidiary of BC Gas Utility Ltd. was Squamish Gas Co. Ltd.

In 2002, BC Gas Inc. purchased Centra Gas BC Inc. and Centra Gas Whistler Inc., adding natural gas customers on the Sunshine Coast and Vancouver Island and piped propane customers in Whistler. In 2003, BC Gas Inc. changed the name of each of its corporate entities to Terasen, creating Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Squamish) Inc., and Terasen Gas (Whistler) Inc.

In 2005, Terasen Inc. (the holding company of the natural gas utilities) was acquired by Kinder Morgan Inc., a US based energy storage and transportation company. On January 1, 2007, Terasen Gas (Squamish) Inc. amalgamated with Terasen Gas Inc. under the name Terasen Gas Inc. Also in 2007, Fortis Inc. acquired Terasen Inc. from Kinder Morgan Inc.

4 Formerly Terasen Gas Inc.
5 Decision and Order G-245-20.

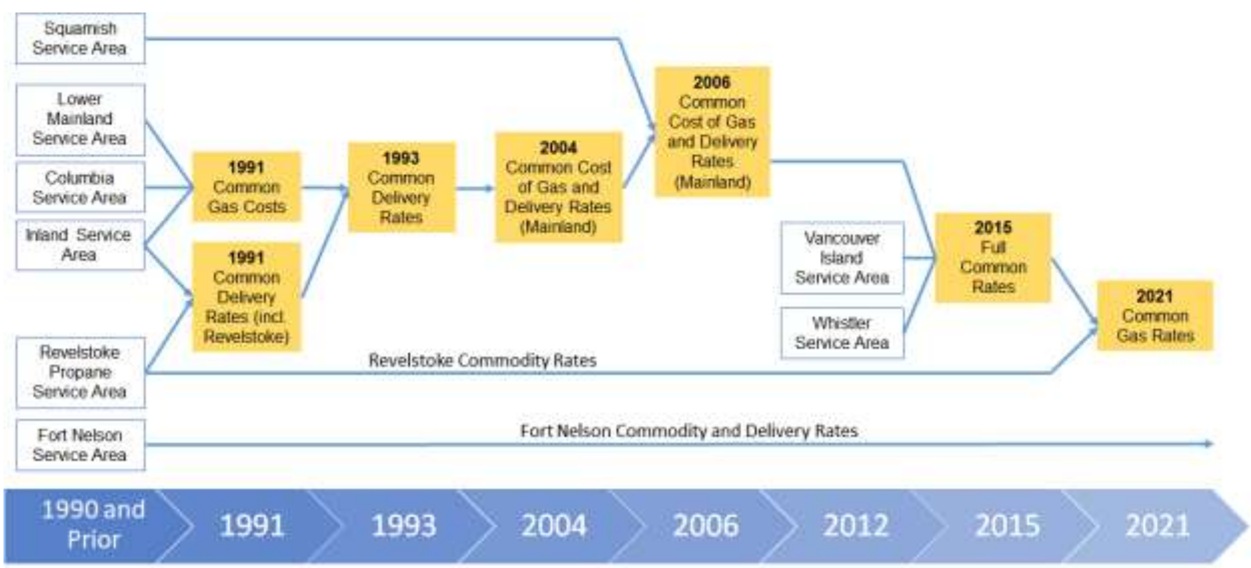
On March 1, 2011, the Terasen group of companies was renamed - Terasen Inc. became FortisBC Holdings Inc., Terasen Gas Inc. became FEI, Terasen Gas (Vancouver Island) Inc. became FortisBC Energy (Vancouver Island) Inc. (FEVI), and Terasen Gas (Whistler) Inc. became FortisBC Energy (Whistler) Inc. (FEW).

On December 31, 2014, FEI, FEVI and FEW were amalgamated as one company under the name of FEI.

3.3.2 Common Rates History

The following figure illustrates the evolution of common rates for FEI. As stated previously, Fort Nelson is now the only service area which is not part of FEI's common delivery and commodity rates.

Figure 3-1: Timeline of Common Rates



3.3.2.1 Development of Common Rates in Most Service Areas

As discussed above, Inland Natural Gas, BC Gas Inc., Columbia Natural Gas Ltd. and Fort Nelson Gas amalgamated in 1989.

In 1991, FEI (then BC Gas) proposed, and the BCUC approved, a gas cost allocation methodology that streamed the gas supply and upstream pipeline and storage costs to the three regions (Lower Mainland, Inland and Columbia) that made up FEI at the time. An account called the Gas Cost Reconciliation Account (GCRA) captured all gas costs.[6]

In 1993, FEI undertook a delivery rate design application where it proposed postage stamp delivery charges for the Lower Mainland, Inland and Columbia regions. At that time, FEI decided to exclude Fort Nelson from this consolidation and postage stamp proposal. The BCUC

[6] Order G-22-92.

approved postage stamp delivery charges for the Inland and Lower Mainland residential, commercial and general firm service customers.[7] Although the BCUC declined to include the Columbia region in the postage stamp delivery charges approved for the Mainland and Inland service areas, the BCUC did allow the Company to set the same delivery rate for Columbia customers. The delivery charges for what was then the three regions have remained identical since that time. As part of its decision and Order G-101-93, the BCUC approved the adoption of a consolidated set of General Terms and Conditions to be applied across the FEI service areas (other than Fort Nelson, as Fort Nelson was not included in the 1993 application).

In 1993, through Order G-68-93, the BCUC approved the consolidation of the Lower Mainland, Inland and Columbia divisions for regulatory purposes.

In 2004, at the request of the BCUC, the GCRA was separated into two portfolios - the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA) - to facilitate the implementation of the Customer Choice Unbundling program. This program allowed customers to purchase their gas supply through marketing firms. Since that time, Mainland (which includes Inland and Columbia service areas) commodity rates have been postage-stamped, while the midstream rates maintained slight differences between these regions until 2015 when common rates became effective for these regions together with Vancouver Island and Whistler, as discussed in Section 3.3.2.3 below.

3.3.2.2 Amalgamation and Common Rates for Squamish and FEI

On October 16, 2006, FEI filed its Advance Annual Review materials in accordance with the 2004-2007 Multi-Year Performance Based Ratemaking (PBR) Settlement. As part of the Annual Review, FEI recommended amalgamation between what was then Terasen Gas Inc. (TGI) and Terasen Gas (Squamish) Inc. (TGS).

Based on the Order in Councils (OICs)[8] issued by the Lieutenant Governor in Council (LGIC) to the BCUC on November 2, 2006, TGI requested and received BCUC approval for the area formerly served by TGS to be treated as part of the TGI Lower Mainland Service area and to be subject to the TGI Tariff.[9]

3.3.2.3 Amalgamation and Common Rates for FEI, FEVI and FEW

On April 11, 2012, FEI and its affiliates filed an application with the BCUC to amalgamate FEVI, FEW and FEI into a single entity and implement postage stamp rates across the amalgamated entity (including Fort Nelson). In its application, FEI stated that it had been operating with a common management structure since the mid-2000s and that it viewed amalgamation as the next logical step towards integration.

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[7] Order G-101-93.
[8] OIC No. 766, 767 and 768, and Vancouver Island Natural Gas Pipeline Special Direction No. 3 (SD No. 3).
[9] Order G-160-06.

In February 2013 in Order G-26-13, the BCUC denied FEI's application for common rates and declined to consider the issue of amalgamation.[10] Following this decision, in April 2013, FEI filed an application for Reconsideration and Variance of Order G-26-13. In this reconsideration and variance application, FEI requested a determination that the proposed amalgamation was in the public interest and that the proposed postage stamp rates for the amalgamated utility (now excluding the service area of Fort Nelson) be approved. The BC Ministry of Energy and Mines intervened in the reconsideration and variance proceeding and issued a letter to the BCUC in support of amalgamation and common rates. The letter stated the following:

> From a public policy perspective, the Ministry is of the opinion that a common rate resulting from the proposed amalgamation of Fortis BC Energy Utilities will have benefits for all FortisBC Energy customers in British Columbia.
>
> Government policy has been to promote access to energy services on a postage stamp rate basis so that all British Columbians benefit from access to services at the lowest average cost.[11]

In February 2014, the BCUC approved the reconsideration and variance application with conditions.[12] The BCUC determined that the amalgamation was beneficial and in the public interest and that it would provide economic and other benefits that were in the public interest to FEI customers as a whole. The BCUC also determined that in the context of FEI as an amalgamated entity, rate stability for the larger group of ratepayers would improve with the implementation of common rates. The BCUC determined that FEI could adopt common rates for the amalgamated entity, subject to LGIC consent (which was approved by OIC No. 300 dated May 23, 2014).

3.3.2.4 Common Cost of Gas Rates for Revelstoke Propane Customers

In July 2019, FEI filed an application with the BCUC for approval to amalgamate Revelstoke propane supply costs with FEI midstream natural gas supply resource costs in the MCRA and to implement a revised propane gas cost rate-setting mechanism. Under the revised rate-setting mechanism, FEI proposed to equalise gas cost recovery rates for both FEI's natural gas customers and FEI's Revelstoke propane customers. This would mitigate historically high volatility in propane commodity pricing and, in consequence, provide rate relief to Revelstoke customers.

From the outset of service in 1991, propane customers in Revelstoke had paid the same delivery rates as FEI natural gas customers, plus a propane commodity charge specific to the Revelstoke area. The propane commodity charges paid by Revelstoke customers had historically been more volatile and higher than natural gas prices on an energy equivalent basis.

[10] Order G-26-13.
[11] FEU Common Rates, Amalgamation Rate Design Reconsideration Phase 2, Exhibit C3-1.
[12] Order G-21-14.

In its Decision and Order G-245-20 issued in October 2020, the BCUC approved FEI's proposal to amalgamate the FEI Revelstoke propane supply costs with the FEI midstream natural gas supply resource costs in the MCRA, resulting in common cost of gas rates for Revelstoke customers. This resulted in Revelstoke propane customers now having common delivery and commodity rates with the rest of FEI's service areas, except Fort Nelson. As part of its decision, the BCUC stated the following:[13]

> The BCUC has recognised the application of postage stamp rates as both just and reasonable in several instances throughout the province, and as an appropriate means of allocating costs to various customer groups. In the present case such an application is not seen as inconsistent with the Bonbright principles. FEI's proposal is considered in keeping with these principles by its seeking to equalize rates fairly across its service territory. It achieves a balanced allocation of costs, promotes price stability and reduces burdens on a significant customer group by means of a proposal which minimizes negative effects and leaves open options for alternatives in the future.

3.3.3 Conclusion

Over the past decades, FEI has sought to consolidate its various divisions and service areas under one legal entity and to unify these service areas through common delivery and commodity rates. With the BCUC's approval in 2020 to implement common commodity rates for Revelstoke customers, the establishment of common rates throughout all service areas is almost complete. The remaining outlier is Fort Nelson, a region which currently serves approximately 2,400 customers who consume less than 5 PJs of natural gas annually. Although included in the same legal entity, Fort Nelson continues to have its own cost of service and rate base. As FEI will explain in the following sections, now is the appropriate time to move Fort Nelson to common delivery and cost of gas rates with the rest of FEI.

[13] Appendix A to Order G-245-20, p. 26.

4. REGULATORY, FINANCIAL AND OPERATIONAL CONTEXT OF FEFN, AND GOVERNMENT POLICY SUPPORTING COMMON RATES

4.1 *INTRODUCTION*

In this section, FEI provides information on the following overarching considerations which were taken into account when developing the proposals contained in the Application:

- Key historical regulatory developments in Fort Nelson;
- The financial and operational environment in Fort Nelson, including the high level of integration already existing between FEI and FEFN, trends in FEFN customer demand, and current and planned capital spending; and
- Government policy related to postage stamp rates.

Each of these overarching considerations is described in the subsections below.

4.2 *FEFN REGULATORY CONTEXT*

4.2.1 Separate Rates and Regulatory Filings

Setting rates separately for FEFN has required either annual or bi-annual revenue requirement applications, and the associated regulatory hearing processes and costs to review these applications.

Additionally, FEFN does not have a materiality threshold for Certificate of Public Convenience and Necessity (CPCN) projects; thus each major project has to be evaluated to determine if a separate CPCN is required, which can result in additional regulatory filings and hearing processes.

For example, FEFN underwent a public hearing process in 2013/14 when it sought approval for a CPCN to construct and operate a transmission pressure pipeline crossing of the Muskwa River. A CPCN was approved for this project in 2014[14] and the estimated cost of the project was $7 million. More recently, as part the BCUC's review of the FEFN Application for Approval of Deferral Account Treatment for 2021 and Changes to the RSAM Rider (2021 Deferral Account Application), the BCUC asked whether FEI intended to file a separate major project filing (either a CPCN or Section 44.2 filing) for the Recreation Centre District Station project as opposed to requesting approval of the capital expenditures as part of the revenue requirement process. The estimated project cost was $682 thousand and, ultimately, the BCUC agreed with FEI that a separate filing was not necessary[15]. However, it is possible that projects of a similar

[14] Order C-2-14.
[15] Decision and Order G-78-21, pp. 9-10.

or greater scope and magnitude could require separate regulatory processes if such a determination was made by the BCUC, as FEFN does not have an established CPCN threshold. If FEFN is part of FEI without a separate rate base, FEFN will assume FEI's threshold, which is currently set at $15 million.

In addition to separate delivery rates, FEFN customers are also charged separate commodity related charges (comprising a midstream rate[16] and a cost of gas rate). FEI must, therefore, file separate quarterly gas cost reports with the BCUC for the Fort Nelson service area.

4.2.2 Changes to FEFN Rate Design Resulting from the 2016 Rate Design Decision

In 2017, FEI filed a supplemental filing to its 2016 Rate Design Application (RDA), which included the first comprehensive review of FEFN's rate design. As a result of its review, FEI proposed a number of changes to FEFN's rate design, including unbundling FEFN rates, moving FEFN rates to a flat rate structure, and rebalancing revenue amongst residential, commercial and industrial customers. The BCUC approved the changes to FEFN's rate design in the RDA Decision.[17] These changes to FEFN rates and rate structures were implemented on January 1, 2019 and are described in more detail as follows:

- Unbundling the different components (cost of gas, midstream, and delivery) of FEFN's residential, commercial and industrial rates;
- Replacing FEFN's existing declining block rate structure with a flat rate structure;
- Renaming FEFN's rate schedules to align with FEI's rate schedule naming conventions (Rate 1 to Rate Schedule 1, Rate 2.1 to Rate Schedule 2 and Rate 2.2 to Rate Schedule 3); and
- Setting the annual consumption threshold separating small (Rate Schedule 2) and large (Rate Schedule 3) commercial customers at 2,000 GJs per year, down from the existing threshold at 6,000 GJs per year. This threshold is consistent with the threshold used in FEI's other service areas.

The result of the changes to FEFN rates and rate structures from the RDA Decision is that FEFN's rate structure is now aligned with FEI's Mainland and Vancouver Island service area.

4.2.3 FEFN 2019-2020 Revenue Requirement

In the FEFN 2019-2020 Revenue Requirement Application (2019-2020 RRA), FEI sought approval from the BCUC of, among other things, delivery rate increases of 4.41 percent and 8.25 percent in 2019 and 2020, respectively, and a CPCN for the extension of FEI's distribution

[16] Midstream rate is also referred to interchangeably as storage & transport rate for the purpose of this Application.
[17] On January 9, 2018, the BCUC issued Order G-4-18 and Reasons for Decision on FEI's proposed Cost of Service Analysis and Revenue to Cost Ratios, and on July 20, 2018 the BCUC issued Order G-135-18 and Reasons for Decision on the balance of FEI's RDA (together referred to as the RDA Decision).

system in FEFN resulting from its purchase of the gas distribution assets from Prophet River First Nation (PRFN Extension).

In its Decision and Order G-48-19 (2019-2020 RRA Decision), the BCUC approved the applied for rate increases and a CPCN for the PRFN Extension.

As part of the 2019-2020 RRA Decision, the BCUC identified and explored two issues related to the FEFN forecast revenue deficiencies and rate increases: (1) the declining FEFN demand forecast; and (ii) the potential implementation of postage stamp rates to address rate pressures experienced in FEFN. The first issue – declining FEFN demand – is discussed further in Section 4.3.2 of this Application. The second issue – postage ramp rates – is discussed here and in Section 4.3.1.

In the 2019-2020 RRA, FEI did not propose to move FEFN to common, or postage stamp, rates; however, FEI did provide a comparison of the delivery rates between FEFN and FEI's Mainland and Vancouver Island service area. The comparison showed that moving FEFN customers to common delivery rates would result in an approximate 6 percent delivery rate increase for residential (Rate Schedule 1) customers, but would result in an approximate 30 percent and 23 percent rate decrease for small commercial (Rate Schedule 2) and large commercial (Rate Schedule 3) customers, respectively.

There were a number of reasons that FEI did not propose moving to common rates in the 2019-2020 RRA. First, at the time of the application, FEI was in the process of applying for a new 2020-2024 multi-year rate plan (MRP) for its Mainland and Vancouver Island service area; therefore, 2020 delivery rates (and the framework with which to set those rates) was not yet in place for FEI, and there was uncertainty as to when such a framework and rates would be in place. Second, FEI was in the process of implementing the rate design changes to FEFN flowing from the previously discussed RDA Decision. These rate design changes resulted in a rebalancing of revenue amongst residential, commercial and industrial customers and, therefore, were causing additional rate pressures for some FEFN customer classes for 2019. When considering the administrative process already underway to implement the rate design changes and the additional rate pressures related to the rate design changes, FEI did not consider it an appropriate time to propose common rates. Finally, FEI was cognizant of the fact that moving to common rates would result in a rate increase to residential customers and wanted some time to consider how future rate changes for FEI and for FEFN might impact that increase.

The BCUC accepted FEI's rationale for not proposing common rates in the 2019-2020 RRA; however, the BCUC made the following observations:[18]

> Based on the magnitude of the rate increases requested and the continuing downward trend of the total energy demand in FEFN, in the Panel's view, unless some significant changes in circumstances were to occur, it is likely that FEFN's

[18] Appendix A to Order G-48-19, pp. 10-11.

> residential customers would not experience a significant rate increase from moving to postage stamp rates in the near future. The Panel agrees with the CEC [Commercial Energy Consumers of BC] that it is not necessary for there to be no rate impacts in order to transition to postage stamp rates, and that transitional impacts can be minimized and managed with sufficient planning and fore-thought.
>
> The Panel recognizes that FEI has not yet filed its RRA to set 2020 rates for FEI, and as such it is not yet in the position to forecast the rate impact of postage stamp rates in 2020.

The BCUC directed FEI to include in the next FEFN RRA a discussion of the potential for postage stamping rates in FEFN, including the following information:[19]

- The forecast rate impact of moving to postage stamp rates for each of FEFN's rate schedules for 2021 and 2022 (or the applicable test period, if different from the two years referenced);
- FEI's assessment of the pros and cons of moving to postage stamp rates in the near future;
- FEI's assessment of the likelihood of the occurrence of factors and circumstances that could result in a reduced or increased rate impact in the near future;
- Proposed mechanisms to reduce or mitigate negative rate impacts to an acceptable level; and
- A proposed time period to implement postage stamp rates.

FEI addresses point 3 of the above BCUC reporting directives (likelihood of factors and circumstances that could result in a reduced or increased rate impact in the near future) in Section 4.3 below. The remaining four points are addressed in Section 5.

4.2.4 Application for Deferral Account Treatment for 2021

On November 6, 2020, FEI filed an application with the BCUC to maintain existing 2020 delivery rates for FEFN effective January 1, 2021 (2021 Deferral Account Application). FEI forecast a 2021 revenue surplus of $132 thousand and requested to record this surplus and any BCUC direct costs related to the regulatory process in a new non-rate base deferral account. This surplus could then be used to mitigate or phase in future rate increases in Fort Nelson, including any that result from moving FEFN to common rates with FEI.

On March 16, 2021, the BCUC approved the 2021 Deferral Account Application[20]. As part of its decision, the BCUC directed FEI to comply with the directive in the 2019-2020 RRA Decision

[19] Appendix A to Order G-48-19, p. 11.
[20] Decision and Order G-78-21.

regarding providing information on the potential for postage stamping rates in FEFN (this information was outlined above in Section 4.2.3 of this Application). The BCUC also stated the following regarding common rates[21]:

> In the Panel's view, the previous directive regarding common rates was not a direction for FEI to file a common rates application. However, given FEI's intention to file a common rates application for FEFN by May 2021, with a planned implementation date of January 1, 2022, the Panel accepts FEI's proposal to provide the requested information in its upcoming common rates application which FEI states will represent its next RRA…
>
> To assess the appropriateness of moving FEFN ratepayers to FEI common rates, a key consideration will be the impact of common rates on FEFN ratepayers. In this context, the Panel acknowledges the comments of customers in this proceeding who state that recent increases in the commodity rates are having negative effects on families and businesses and that any further rate increase would be detrimental. The Panel also notes that FEI states it is sensitive to rate impacts on its customers and that it seeks to provide safe and reliable service to customers at the lowest reasonable cost. The Panel urges FEI to take these considerations into account as it moves forward with its common rates application or next RRA.

4.3 *FEFN FINANCIAL AND OPERATIONAL CONTEXT*

This section provides the financial and operational context for Fort Nelson and how this context supports a move to common rates, including the following:

- The high level of integration which already exists between FEI and FEFN, as reflected by the majority of FEFN's operating costs being attributable to a shared services allocation from FEI, and the benefits to FEFN operationally and financially of this arrangement;
- The declining trend in FEFN's customer growth and natural gas demand and how this contributes to greater delivery rate pressures for FEFN;
- The impact of maintaining a separate rate base for FEFN, as required capital investments to maintain the FEFN distribution system are currently only recovered from FEFN's small customer base and therefore can result in increased delivery rate pressure; and
- A comparison of delivery rate volatility between FEI and FEFN, which shows that FEFN has historically experienced much greater delivery rate volatility due to its small customer base.

[21] Decision and Order G-78-21, p. 12.

4.3.1 Benefits of FEFN's Integration with FEI

Despite FEFN continuing to maintain a separate rate base with its own delivery rates and separate gas cost portfolio with its own commodity related charges, FEFN is already integrated with FEI from an operations and management perspective, with all business functions being provided to FEFN by FEI. In the following subsections, FEI discusses the shared services provided to FEFN and how the provision of these services are incorporated into FEFN's revenue requirement and gas supply portfolio costs.

4.3.1.1 FEFN's Delivery Rates

FEFN's delivery rates are set through the revenue requirement application process. The revenue requirement is comprised primarily of operations and maintenance (O&M) expenses, depreciation and amortization expenses, taxes and return on rate base. Most of FEFN's O&M and a portion of capital expenditures are allocated from FEI, reflecting an already existing high level of integration of FEFN's operations and revenue requirement.

With regard to O&M, FEFN is supported by two direct full-time field employees who reside in Fort Nelson, while the remainder of the management, operational and administrative activities are provided by FEI's resources through Shared Services. As such, a large portion of FEFN's O&M expenses are charged through a shared services fee, which is an allocation of FEI's O&M expense based on FEFN's customers as a percentage of FEI's customers. This allocation method has been in place since 2008[22].

The shared services fee is the costs for the portion of FEFN's operations that are performed using FEI's resources instead of direct resources in FEFN. Examples of shared services provided by FEI include the following:

- Customer service functions, such as FEI's call centre, which provides support to FEFN customers;
- Asset reliability and integrity management;
- Natural gas resource and supply management;
- Conservation programs;
- Communication and consultation with local government and communities;
- Accounting and finance functions; and
- Regulatory support.

FEFN is operated and managed by FEI in the same way that FEI operates the other parts of its system.

[22] As approved by Order G-27-08.

Table 4-1 below provides the shared services fee included in FEFN's Gross O&M between 2011 and 2020. As shown in the table, FEFN's Gross O&M expense is predominately comprised of the shared services fee charged to FEFN from FEI, representing on average 54 percent of FEFN's total Gross O&M expense over the last ten years.

Table 4-1: FEFN's Shared Service Fee in O&M Expense ($000s)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Avg.
Shared Service Fee ($000s)	353	496	511	490	516	503	491	495	515	562	493
Gross FEFN O&M Expense ($000s)	853	915	1,182	969	969	941	745	909	821	906	921
% Shared Service Fee	**41%**	**54%**	**43%**	**51%**	**53%**	**53%**	**66%**	**54%**	**63%**	**62%**	**54%**

With regard to capital additions, commencing in 2017 FEI has been allocating capital costs (Intangible and General Plant) to FEFN that are attributable to application software such as Microsoft Office, SAP, and other software programs as well as computer hardware required to carry out day-to-day operations[23]. Table 4-2 below shows the total capital additions related to application software and computer hardware allocated to FEFN since 2017 and the associated revenue requirement impact.

Table 4-2: FEFN's Allocated Intangible and General Plant Capital Additions ($000s)

	2017	2018	2019	2020
Actual Allocated Capital Additions ($000s)	116	49	50	72
Revenue Requirement Due to Allocated Capital Additions				
Earned Return ($000s)	20	20	19	17
Depreciaton & Amortization ($000s)	56	55	68	83
Income Tax Expense ($000s)	10	6	14	17
Total ($000s)	**86**	**81**	**101**	**117**

As shown in Table 4-3 below, overall, an average of 24 percent of FEFN's revenue requirement over the last ten years has been based on allocations from FEI through the shared services fee and capital additions for application software and computer hardware. The remaining approximately 75 percent of FEFN's revenue requirement is related to the direct capital expenditures required to maintain and improve FEFN's gas distribution system as well as taxes and financing costs.

Table 4-3: Comparison of FEFN's Allocated and Total Revenue Requirement ($000)

$000s	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Shared Service Fee	353	496	511	490	516	503	491	495	515	562
Allocated Intangible & General Plant	-	-	-	-	-	-	86	81	101	117
Total Allocated Revenue Requirement	**353**	**496**	**511**	**490**	**516**	**503**	**577**	**576**	**616**	**679**
FEFN Approved Revenue Requirement	1,762	1,874	1,935	1,936	2,275	2,507	2,378	2,489	2,415	2,521
% Total Allocation of FEFN Revenue Requirement	**20%**	**26%**	**26%**	**25%**	**23%**	**20%**	**24%**	**23%**	**25%**	**27%**
Average % Allocation (2011 - 2020)	24%									

[23] FEI Annual Review for 2017 Delivery Rates Application, pp. 57-58.

FEFN customers have benefited and continue to benefit in various ways through the functional services provided by FEI, which is a much larger gas distribution company than FEFN would be on a standalone basis. Some of these benefits include:

- Access to the necessary resources, expertise and training in all areas affecting gas distribution utilities at lower costs than having the same resources and expertise obtained by FEFN;
- Access to low cost capital funding thus reducing carrying costs of capital;
- Access to the buying power of a larger company, reducing the costs of pipe and other materials and supplies; and
- Access to the commodity-related benefits discussed in Section 4.3.1.2 below.

4.3.1.2 FEFN's Gas Supply Portfolio

FEFN's commodity and midstream related charges are set through the gas cost reports which are filed and reviewed quarterly by the BCUC. Although FEI tracks FEFN's gas supply portfolio separately from FEI, FEFN benefits from being part of FEI. This is primarily because FEI is a large regional buyer of natural gas and a significant holder of various natural gas storage, transportation, peaking and other gas supply arrangements that are designed to mitigate and optimize gas supply costs for the overall gas costs portfolio that include the FEFN service area.

To manage FEFN's daily load requirements, FEI uses natural gas supply and third party transportation services. Natural gas supply is sourced by FEI from a producer or a gas marketer 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 on the Westcoast Energy Inc. (Westcoast)[24] T-North system in order to facilitate the movement of commodity supply each day from the plant outlet for delivery to Fort Nelson.

Historically, FEI has contracted the commodity supply for Fort Nelson with qualified producers active in northeast BC. FEI has established long-term relationships with these producers, which helps FEI contract firm term supply to Fort Nelson on favourable and flexible terms for its daily requirements. For instance, given the relatively small volume required to service FEFN, the producers agreed to a unique arrangement that allowed FEI to take only what it requires based on the next day's load forecast for Fort Nelson rather than taking 100 percent 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. Further, since there is no industry standard or published index to establish the price for this gas, FEI's supply agreement for FEFN with the producers has incorporated a pricing mechanism based off the closest market hub with a published index, which is Station 2.

Over the past several years, there has been a significant decline in the commodity price at the regional supply hubs (i.e., Station 2 and AECO/NIT), which has caused economic challenges to

[24] Westcoast is a subsidiary of Enbridge Inc.

producers that are either currently or were actively processing gas supply at the Fort Nelson plant. This has resulted in production from the Fort Nelson plant steadily declining, a development that FEI has been monitoring. Given the declining production from the Fort Nelson plant, the producers informed FEI in 2019 that they would not be able to renew the supply contracts for the Fort Nelson service area. In the short term, FEI has been able to reach agreement for FEFN supply with a gas marketer, using terms and conditions similar to FEI's past agreements with the producers. However, if the supply from the Fort Nelson plant continues to decline, FEI may not be able to negotiate this type of agreement in the future.

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. Any excess or shortfall in the commodity supply based on Fort Nelson's demand for the actual gas day is managed via a balancing agreement that FEI has with Westcoast for its overall portfolio. FEI and Westcoast then settle the cumulative imbalance for the overall portfolio due to over-or-under deliveries over time, in order to manage imbalances on a timely basis.

Furthermore, for gas cost forecasting purposes, and consistent with the existing rate-setting methodology, FEFN's gas cost recovery rates include an allocation of certain costs from the FEI overall gas supply portfolio. For instance, the winter commodity, based on gas quantity proportions, is costed at 33.3 percent using an Aitken Creek pricing model, and the remaining 66.7 percent is split between hedged and market-based pricing, with the hedged percentage being determined from the actual level of financial hedging within the FEI overall commodity portfolio. For summer commodity, the costing is split between hedged and market-based pricing, with the hedged percentage also being determined from the actual level of financial hedging within the FEI overall commodity portfolio.

In addition, the Aitken Creek pricing model is based on the physical price hedge within the FEI overall gas supply portfolio derived from injecting gas into the Aitken Creek storage facility during the summer, thereby capturing the typically lower summer commodity prices, and withdrawing this summer-priced gas during the following winter. The Fort Nelson commodity pricing calculations which benefit from this physical price hedging methodology also include an allocation of the storage demand related charges within the Aitken Creek pricing model.

Lastly, Fort Nelson's gas costs also include an allocation of costs related to the Westcoast T-North Short-Haul Firm Transportation Service (T-North Short-Haul) held within the FEI overall gas supply portfolio. The T-North Short-Haul allows for the scheduling of gas from a receipt point at the Fort Nelson gas plant outlet to the interconnect with FEI's gas distribution system in Fort Nelson.

In summary, FEI contracts for gas supply resources based on the regional needs across its entire diverse system. FEI's pool of gas supply resources and contracting with a diverse set of counterparties are designed to provide security of supply and diversity in the portfolio, including Fort Nelson, while minimizing the costs of the total portfolio. The total pool of gas supply resources is used collectively, and as required, to manage the total daily load for FEI that includes Fort Nelson. As a result, Fort Nelson is already integrated as part of FEI's overall gas supply portfolio with the benefits of having costs optimized through FEI's various supply arrangements within the overall gas supply portfolio.

4.3.2 Declines in FEFN's Demand and Impact to FEFN's Delivery Rates

FEFN's demand has been trending downwards over a number of years, and this decline has a negative impact on FEFN customers' delivery rates. The following subsections provide details of FEFN's historical and forecast demand as well as customer counts, and the delivery rate impact to FEFN due to this continuing downward demand trend.

4.3.2.1 Historical and Forecast Energy Consumption

Figure 4-1 below shows the actual demand over the last ten years from 2011 to 2020, and a three-year demand forecast from 2021 to 2023. As shown in Figure 4-1, actual demand has been on a declining trend since 2014 from approximately 645 TJs to 518 TJs by 2020. This is equivalent to a decline of approximately 20 percent at an average rate of approximately 21.2 TJs per year. The demand forecast is expected to continue to decline from 2021 to 2023 at an average rate of 20.3 TJs per year.

FEI notes the demand and customer forecasts for 2021 to 2023 are based on forecasting methods that are consistent with the method used in prior years. For detailed information on FEI's demand forecasting methods and FEI's demand forecast calculations and assumptions for calculating Seed 2021 and Forecast 2022 and 2023 energy demand and revenue, please refer to Appendix A.

Figure 4-1: Actual and Forecast Demand

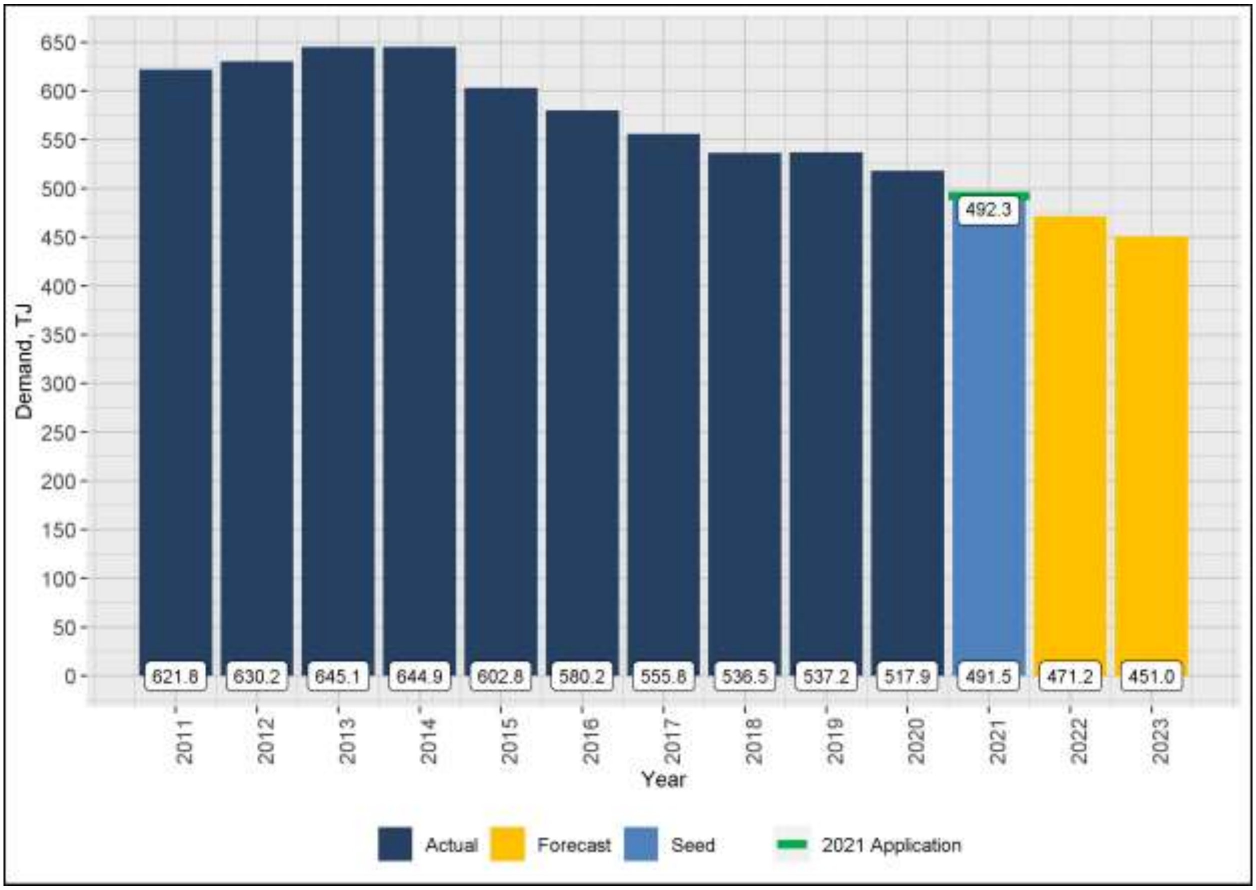


Figure 4-2 below shows the residential demand actuals from 2011 to 2020 and forecast from 2021 to 2023. Residential demand declined by ten percent from 2013 to 2020, at an average rate of 3.8 TJs per year. The forecast of residential demand is expected to further decrease at an average rate of 4.3 TJs per year, mostly due to the declining customer counts in Fort Nelson (see Section 4.3.2.2 below), but also partly due to the declining use rate per customer.

Figure 4-2: Actual and Forecast Residential Demand

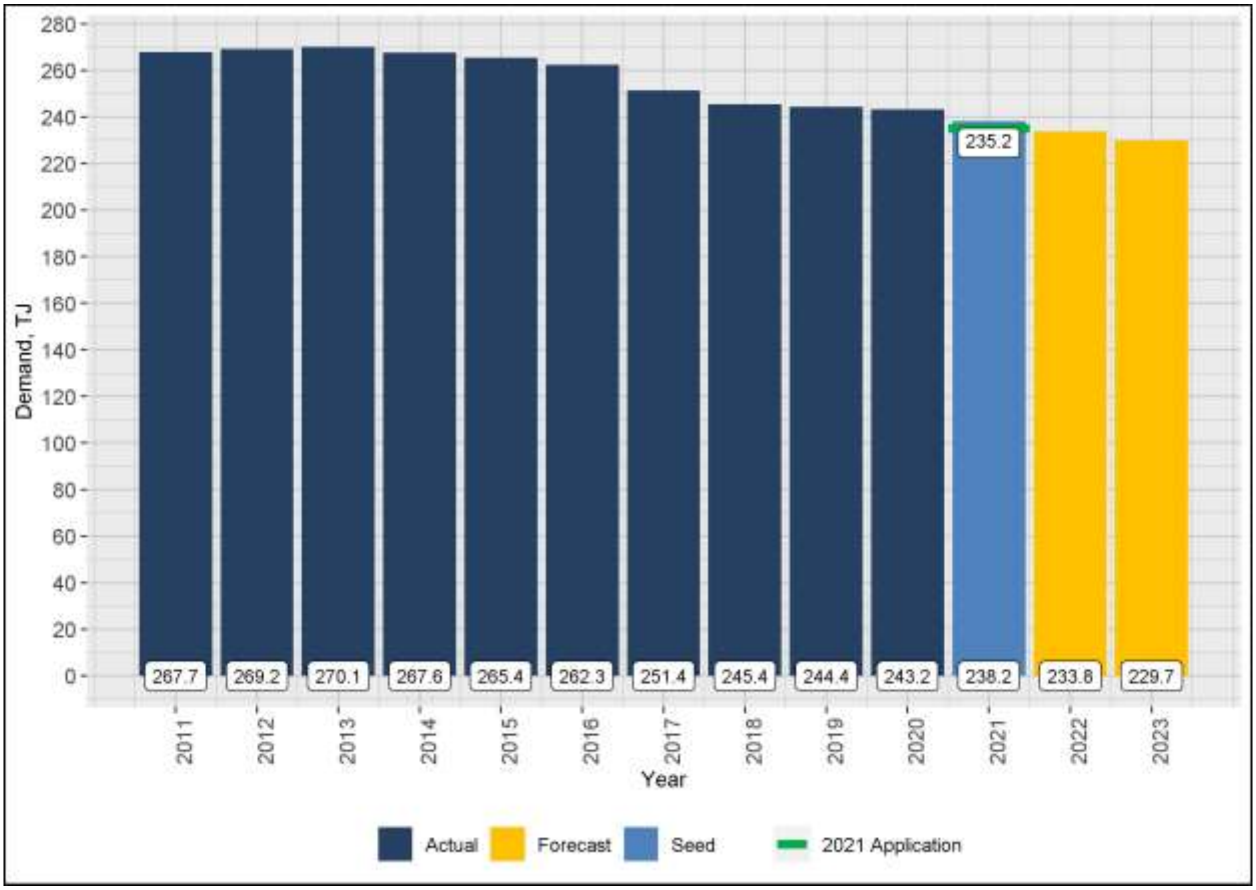
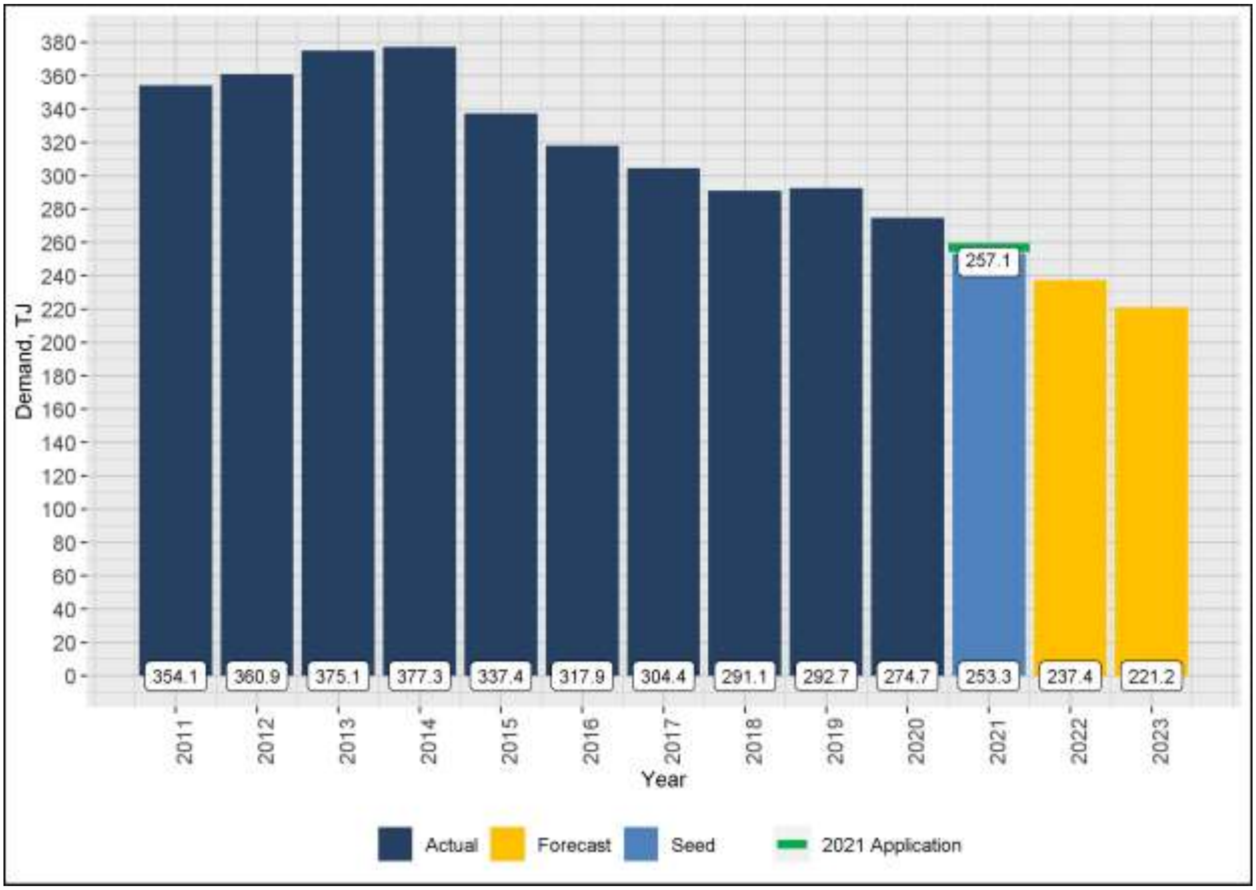


Figure 4-3 below shows the commercial and industrial demand actuals from 2011 to 2020 and forecast from 2021 to 2023. The commercial and industrial demand also experienced a decline over the last several years from a peak of 377 TJs in 2014 down to 275 TJs in 2020 (a decline of 27 percent at an average rate of 17 TJs per year). Based on the recent trend of actual demand, the commercial and industrial demand forecast is expected to further decrease at an average rate of 16.1 TJs per year.

Figure 4-3: Actual and Forecast Commercial and Industrial Demand[25]



The primary cause of the decline in commercial and industrial demand has been the loss of the two RS 25 industrial customers that previously operated in Fort Nelson (both owned by Canfor) known as the Tackama and Polarboard sites. Canfor shut down both sites in 2008, but both sites continued to consume natural gas for space heating to preserve the assets. This reduced the natural gas demand from approximately 200 TJs to approximately 60 TJs per year. The Tackama facility continued to use gas for space heating until 2015 when the equipment was sold, which resulted in a further reduction in demand of approximately 15 TJs and is reflected in the decline from 2015 to 2016 shown in the figure above. The Polarboard site continued to use natural gas until the location and assets were sold in November 2020, at which time the new owner switched from RS 25 to a bundled natural gas service under RS 3. The new owners will be using natural gas for space heating while they liquidate the Polarboard assets and convert the facility into a pellet plant. FEI does not know at this time what the future natural gas demand will be for the pellet plant and has not included any demand beyond space heating in the forecast.

[25] As of 2021, FEFN no longer has any Industrial (RS 25) class customers. The last industrial customer was switched from RS 25 to the Large Commercial (RS 3) customer class in November 2020.

4.3.2.2 Historical and Forecast Customers

Figure 4-4 below shows the historical customer count from 2011 to 2020 and forecast customer count from 2021 to 2023. The forecast customer count is based on the actual customer count from prior years plus the forecast customer additions as described in Appendix A. As shown in the figure below, the Fort Nelson aggregate customer count peaked in 2015 at 2,446 customers. However, since 2015, FEFN has been experiencing a continuous declining trend in customer count at an average rate of approximately 20 customers per year to 2,348 in 2020. This decline is expected to continue at an average rate of approximately 17 customers per year.

Figure 4-4: Actual and Forecast Customers

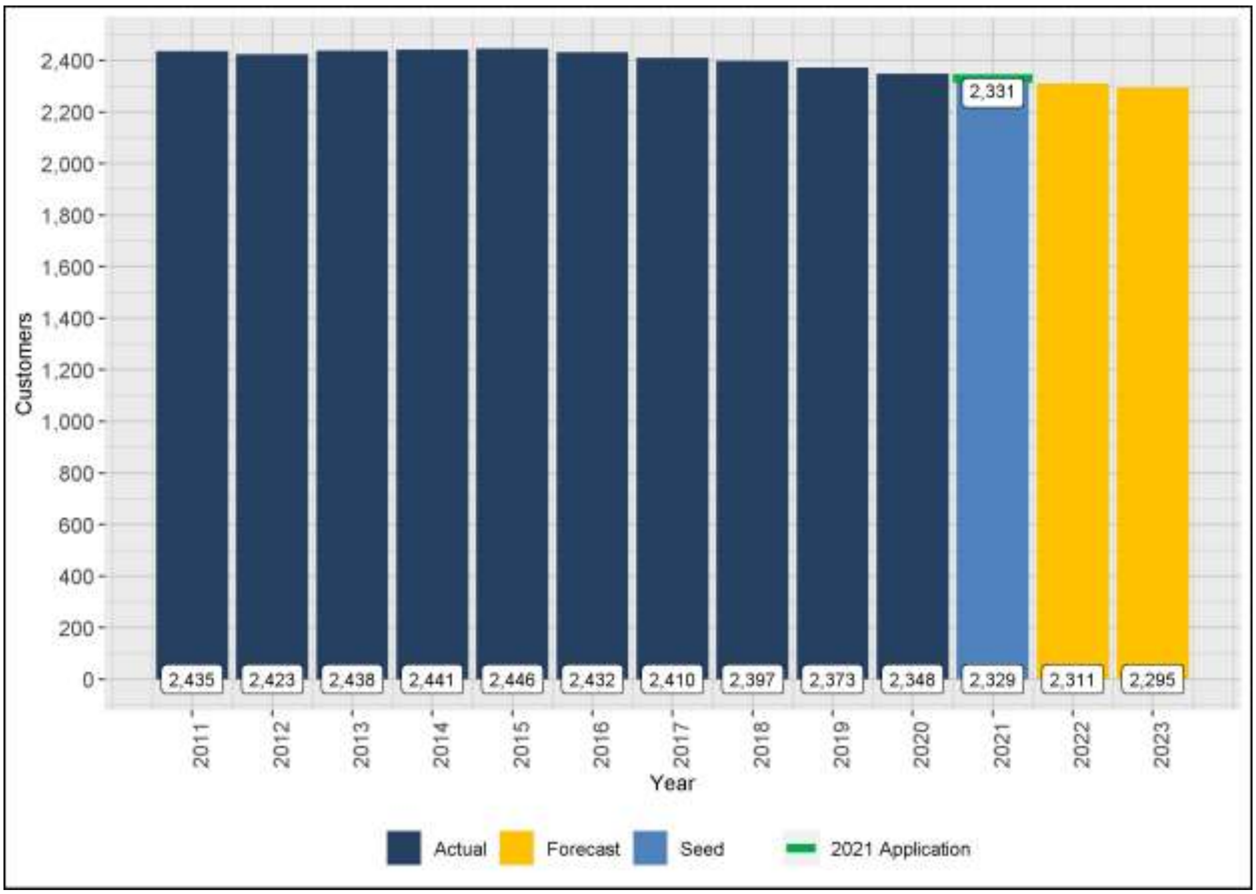


Figure 4-5 below shows the residential customer count actuals from 2011 to 2020 and forecast from 2021 to 2023. The number of Fort Nelson residential customers peaked in 2015 at 1,963 customers, but has been on a steady decline since that time. Between 2015 and 2020 the residential customer count declined by an average of approximately 17 customers per year. Based on the trend in recent years, the decline in residential customers is forecast to continue at an average rate of approximately 13 customers per year.

Figure 4-5: Actual and Forecast Residential Customers

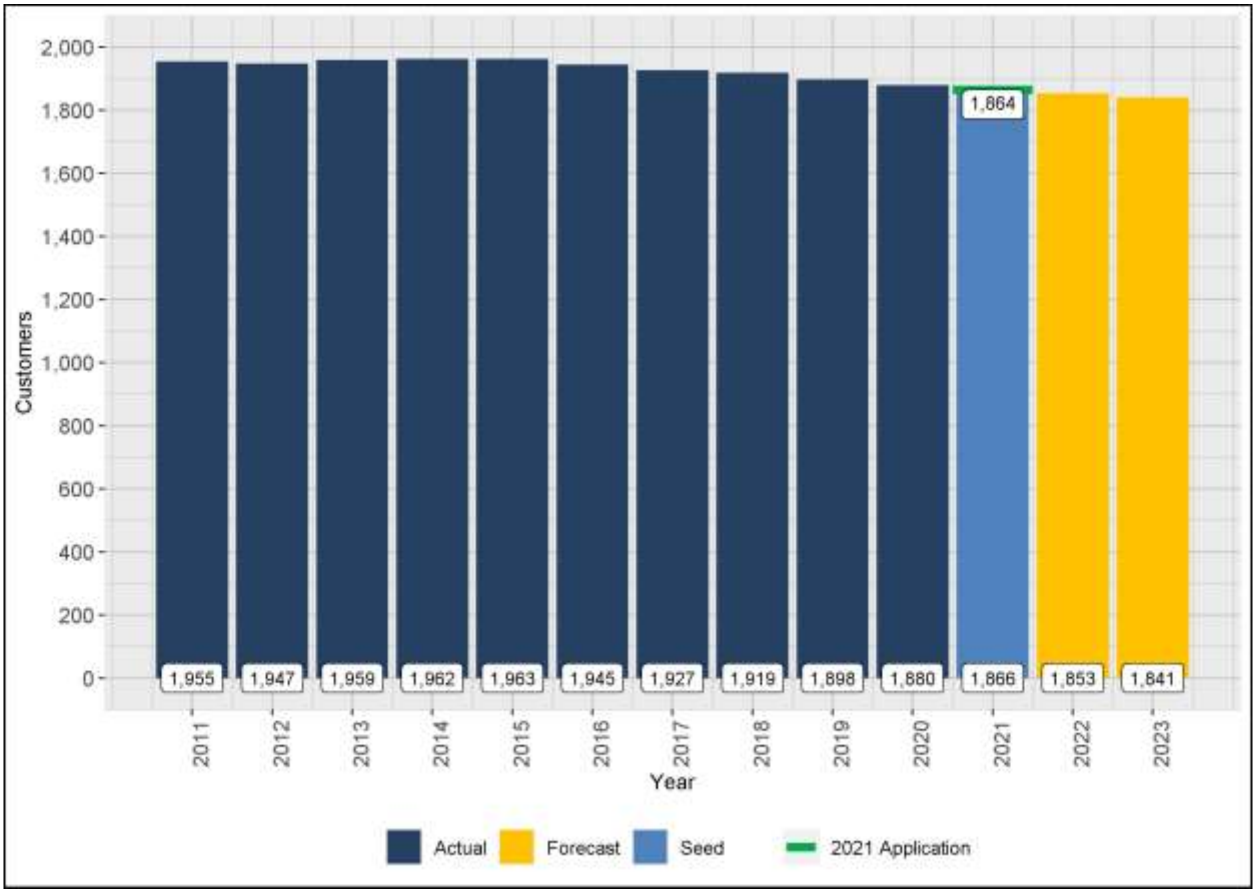
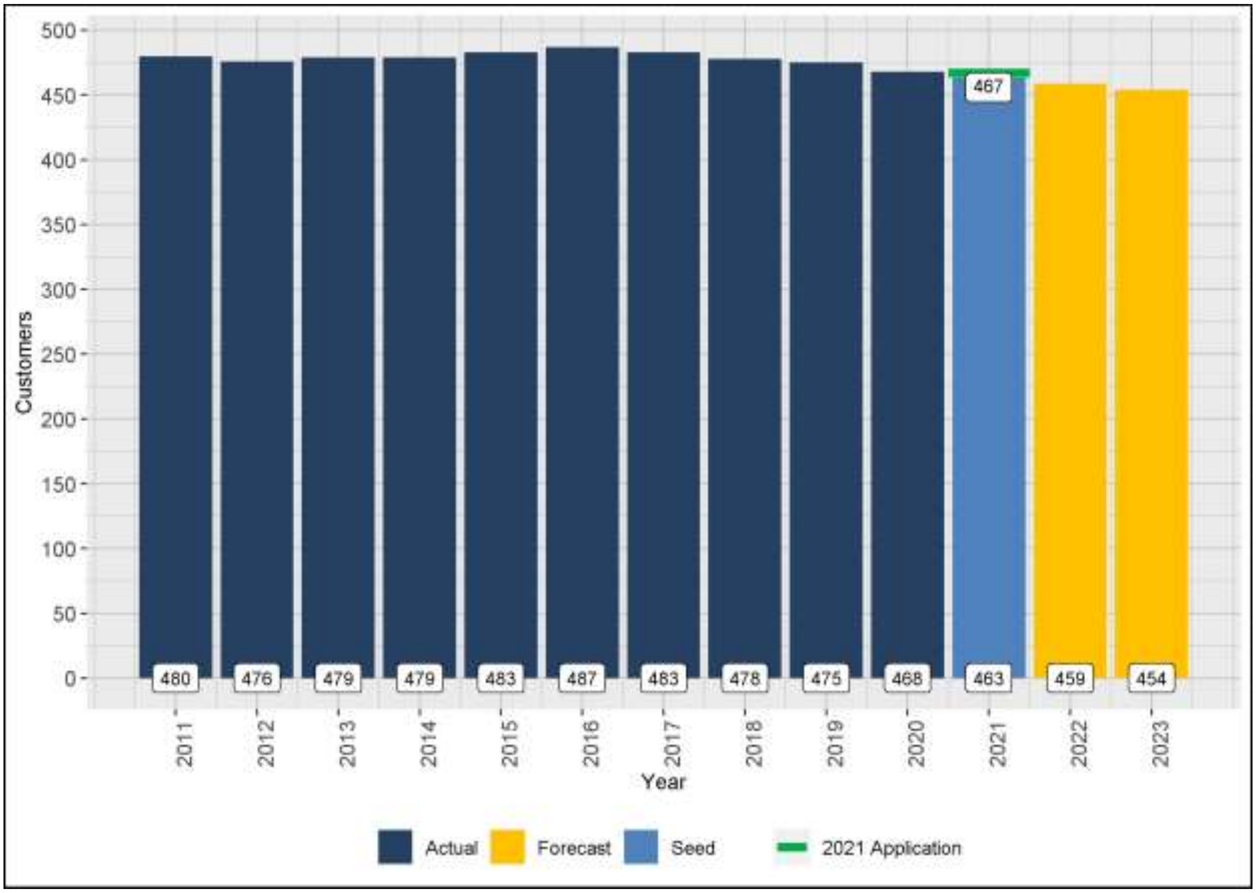


Figure 4-6 below shows the Fort Nelson commercial and industrial customer count actuals from 2011 to 2020 and forecast from 2021 to 2023. The commercial and industrial customers peaked at 487 customers in 2016 before declining to 468 customers by 2020 at a rate of approximately five customers per year. As discussed in Section 4.3.2.1 above, since November 2020, Fort Nelson no longer has any industrial customers. The last remaining industrial customer switched to the RS 3 Large Commercial customer class in 2020. The decline in commercial customers is forecast to continue at an average rate of five customers per year.

Figure 4-6: Actual and Forecast Commercial and Industrial Customers

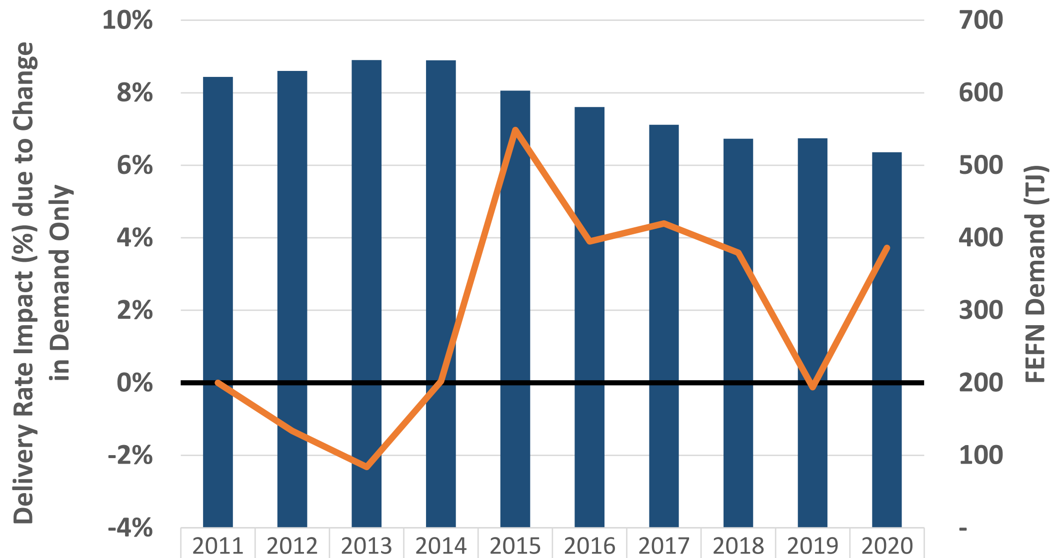


4.3.2.3 Delivery Rate Impact due to Decline in FEFN's Demand

The decline in FEFN's energy demand over the recent years has contributed to the increase in delivery rates. As shown in Figure 4-1 in Section 4.3.2.1, the total energy demand in FEFN peaked at approximately 645 TJs in 2014 but has been on a continuous decline since then. Between 2014 and 2020, the actual energy demand in FEFN was reduced by 127 TJs which is approximately 20 percent or 21 TJs per year, and this decline is forecast to continue.

Figure 4-7 below shows the associated delivery rate impact due to the change in energy demand between 2011 and 2020. FEI has held FEFN's revenue requirement constant in this analysis to isolate the impact of the decreased energy demand. As the figure below shows, since 2014, the decline in energy demand in FEFN resulted in delivery rate impacts that ranged from 3.6 percent to 7 percent. Overall, the cumulative delivery rate impact between 2014 and 2020 is approximately 22.5 percent or an average of approximately 3.2 percent per year. For comparison, a decline of approximately 127 TJs (645 TJs in 2014 to 518 TJs in 2020) is approximately 0.07 percent of FEI's 2021 total approved non-bypass demand forecast of approximately 194,999 TJs, which would have a delivery rate impact of only 0.07 percent to FEI's non-bypass customers, assuming the same level of decline all occurred in 2021.

Figure 4-7: FEFN's Delivery Rate Impacts due to Decline in Demand from 2011 to 2020



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Demand (TJ)	622	630	645	645	603	580	556	537	537	518
Effective Rate Change (%)	0.0%	-1.3%	-2.3%	0.0%	7.0%	3.9%	4.4%	3.6%	-0.1%	3.7%

4.3.3 Impacts of Historical and Forecast Capital Additions

As previously explained, Fort Nelson currently maintains a separate rate base from FEI and, as a result, increases to rate base driven by, among other things, large capital projects and ongoing sustainment activities are absorbed by Fort Nelson's small customer base through delivery rate increases. In the case of large capital projects, the delivery rate impact can be very significant, as was the case with the Muskwa River Crossing Project which entered rate base in 2015 and was the primary driver of an approximately 16.67 percent delivery rate increase in 2015.

The following subsections provide information on the historical capital spending undertaken in Fort Nelson and the expectations for future capital spending.

4.3.3.1 Historical Capital Additions

The following Table 4-4 shows all actual capital additions over the last 10 years from 2011 to 2020, broken down into categories of "Intangibles", "Transmission", "Distribution" and "General Plant / Other". As the table below indicates, the majority of the capital additions for FEFN were related to sustainment capital projects for the transmission and distribution assets, especially since 2015 in which there have been a number of significant capital projects.

Table 4-4: Historical Capital Additions ($000s)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Intangibles	-	-	63	75	70	-	74	27	26	45
Transmission	84	8	20	84	4,475	239	54	193	23	-
Distribution	314	77	230	308	241	581	302	350	505	161
General Plant/Other	3	41	75	54	40	182	50	23	24	27
Total	**401**	**126**	**388**	**521**	**4,826**	**1,002**	**480**	**593**	**578**	**233**

Table 4-5 below provides a number of significant sustainment capital projects undertaken in FEFN since 2015.

Table 4-5: Historical Significant Capital Projects ($000s)

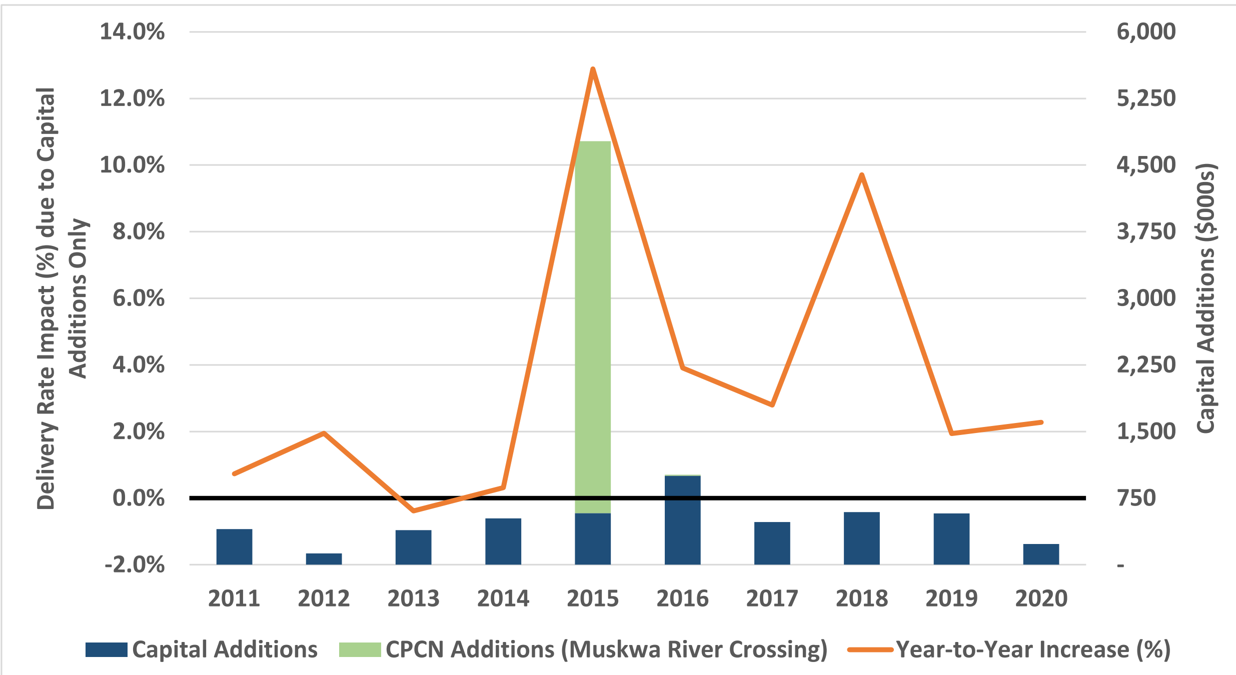
	2015	2016	2017	2018	2019	2020
Transmission System						
Fort Nelson Lateral - Muskwa River Crossing CPCN	$ 4,187	$ 10				
Fort Nelson Lateral - Creek Crossing Protection	30	45	7			
Fort Nelson Lateral - New Raven Crescent Road Crossing		161				
Fort Nelson Lateral and Loop - Crossover Valves Upgrade	250	23				
Fort Nelson Loop - Valve Replacement FN28				193	14	
Subtotal	**$ 4,468**	**$ 239**	**$ 7**	**$ 193**	**$ 14**	**$ -**
Distribution System						
Fort Nelson Gate Station - Pressure Control Upgrade	$ 41	$ 74				
Fort Nelson Gate Station - Electrical and Telemetry Upgrade		165				
Muskwa Gate Station - Line Heater, Telemetry, and Electric Upgrade					241	9
Main Replacements/Renewal Program			171	272	196	56
Subtotal	**$ 41**	**$ 240**	**$ 171**	**$ 272**	**$ 436**	**$ 64**
Total	**$ 4,509**	**$ 479**	**$ 178**	**$ 465**	**$ 450**	**$ 64**

The most significant sustainment capital project was the Muskwa River Crossing CPCN, which was approved by Order C-2-14. The Muskwa River Crossing project was completed in 2014 and entered rate base in 2015. This project and also the Creek Crossing Protection project were necessary as a result of erosion caused by high water flows which put the pipelines at risk of damage from debris. Other significant capital work on the transmission system included the New Raven Crescent Road Crossing which involved replacing a section of the pipeline to address a new road crossing in order to comply with industry standards, and the valve replacement projects for the Fort Nelson lateral and loop to ensure operability for routine pipeline work or emergency response.

For the distribution system, FEI has been undertaking a distribution mains renewal program for FEFN since 2017 for the purpose of reducing the risk to public safety and the likelihood of FEFN having to undertake an emergency response due to leaks discovered. Between 2017 and 2020, 10 distribution main renewals were completed which were prioritized based on age, past history and suspected undesirable installation practices or conditions. Other significant sustainment capital projects since 2015 on the distribution stations included the required upgrades of line heater, electrical, telemetry and pressure control at the Fort Nelson Gate Station and the Muskwa Gate Station to ensure reliable and safe operation of the equipment and to enhance FEI's ability to monitor the operation of the stations.

Despite the delivery rate impact due to these capital projects, all were important and necessary in order to provide continuous, safe, and reliable service to FEFN customers. Figure 4-8 below shows the delivery rate impact in percentage due to all capital additions in FEFN between 2011 and 2020. The cumulative capital additions since 2011 are approximately $9.15 million which resulted in a cumulative delivery rate impact of approximately 43 percent, or an average of approximately 4.3 percent per year.

Figure 4-8: FEFN Delivery Rate impact due to Historical Capital Additions from 2011 to 2020[26]



4.3.3.2 Forecast of Significant Capital Projects

The FEFN system will continue to require capital investment in the future in order to maintain continuous, safe and reliable service. In Table 4-6 below, FEI identifies a number of sustainment capital projects to both the transmission and distribution systems that are currently projected to be completed and in-service by the end of 2021, as well as forecasts for 2022 and 2023, though the timing and cost of these projects may be subject to change as development of the projects progress.

[26] The delivery rate increase in 2018 is primarily due to the Muskwa Cost of Service (COS) deferral account (i.e., amortization credit of $116 thousand per year) fully amortized in 2017.

Table 4-6: 2021 Projected and 2022 & 2023 Forecast Significant Capital Additions ($000s)

	2021 Projected	2022 Forecast	2023 Forecast
Transmission System			
Fort Nelson Control Station - Install Telemetry	$ 278	$ 10	
Fort Nelson Control Station - Install Gradient Control Mat	93	2	
Subtotal	**$ 371**	**$ 12**	**$ -**
Distribution System			
Main Replacements/Renewal Program	$ 355	$ 167	$ 167
Recreation Centre District Station - Upgrade		623	32
Main Alteration - Tamarack Crescent	150		
Subtotal	**$ 505**	**$ 790**	**$ 199**
Total	**$ 876**	**$ 803**	**$ 199**

For the transmission system, FEI plans to install telemetry at the Fort Nelson Control Station, similar to what is already installed at the Fort Nelson and Muskwa Gate Stations, for monitoring the operation of the station. This station controls the pressure of the gas flowing into the transmission system from Enbridge and thus ensures compliance with industry standards. As well, a gradient control mat is planned to be installed to protect workers' safety from induced voltages on the above ground piping from the nearby power facility.

For the distribution system, FEFN will be continuing the mains renewal/replacement program that started in 2017. A number of the projects were initiated in 2020 which will be completed in 2021. FEI forecasts the planned main renewal/replacement program will be completed by 2023.

FEFN will also be undertaking a main alteration near Tamarack Crescent in 2021. This involves replacing 425 m of NPS2 main that is currently located in the backyards of many residential lots. Over the years, vegetation and other structures and encumbrances have been located over top of the main and it is now very difficult to perform leak surveys or to access. Replacing this main with one on the front side of the residences and running new services will eliminate the hazards associated with having the main in the backyards.

For additional details on FEI's Projected 2021 and Forecast 2022 capital additions, please refer to Section 8 of the Application.

FEI notes that it has not identified all capital projects at this time. It is likely that the need for future projects will arise in the upcoming years beyond 2023 as well as additional projects to those identified in Table 4-6 above. Examples of such work include:

- Replacement of transmission pipeline valves (there are approximately eight that have not yet been replaced);
- Replacement of telemetry components due to obsolescence (lifetimes for these components are becoming shorter due to manufacturer/supplier changes);

- New road crossings of the transmission pipelines necessitating replacement of the pipe to be under the proposed road; and
- Advanced Metering Infrastructure (AMI) project[27], which includes replacing existing customer meters with advanced meters and associated infrastructure, and installing communicating sensors on pipeline.

In summary, FEI expects similar levels of capital additions will continue in the FEFN service area and these additions will increase delivery rates for FEFN customers.

4.3.4 Delivery Rate Volatility

As discussed in Sections 4.3.2 and 4.3.3, FEFN has been experiencing a decline in energy demand since 2015 which coincides with some significant capital projects entering rate base over the same period, including the Muskwa River Crossing CPCN and the distribution mains renewal program. As a result of these factors and FEFN's small customer base, FEFN has experienced relatively higher delivery rate increases since 2015 and much greater delivery rate volatility compared to FEI. Figure 4-9 below compares the 10-year approved annual delivery rate increase for both FEFN and FEI between 2012 and 2021. The average increase over the 10-year period for FEFN customers is 5.59 percent compared to an increase of only 2.41 percent for FEI customers. Figure 4-9 below also shows that FEI has relatively lower delivery rate volatility over this 10-year period. This is because FEI has a much broader customer base (i.e., over 1 million customers) and rate classes to absorb changes in costs and customer demand compared to FEFN, which has a relatively smaller and less diversified customer base (i.e., approximately 2,400 customers and no industrial class customers).

[27] Included as part of FEI's AMI CPCN Application, filed with the BCUC on May 5, 2021.

Figure 4-9: 10 Year Delivery Rate Change (FEFN vs. FEI)

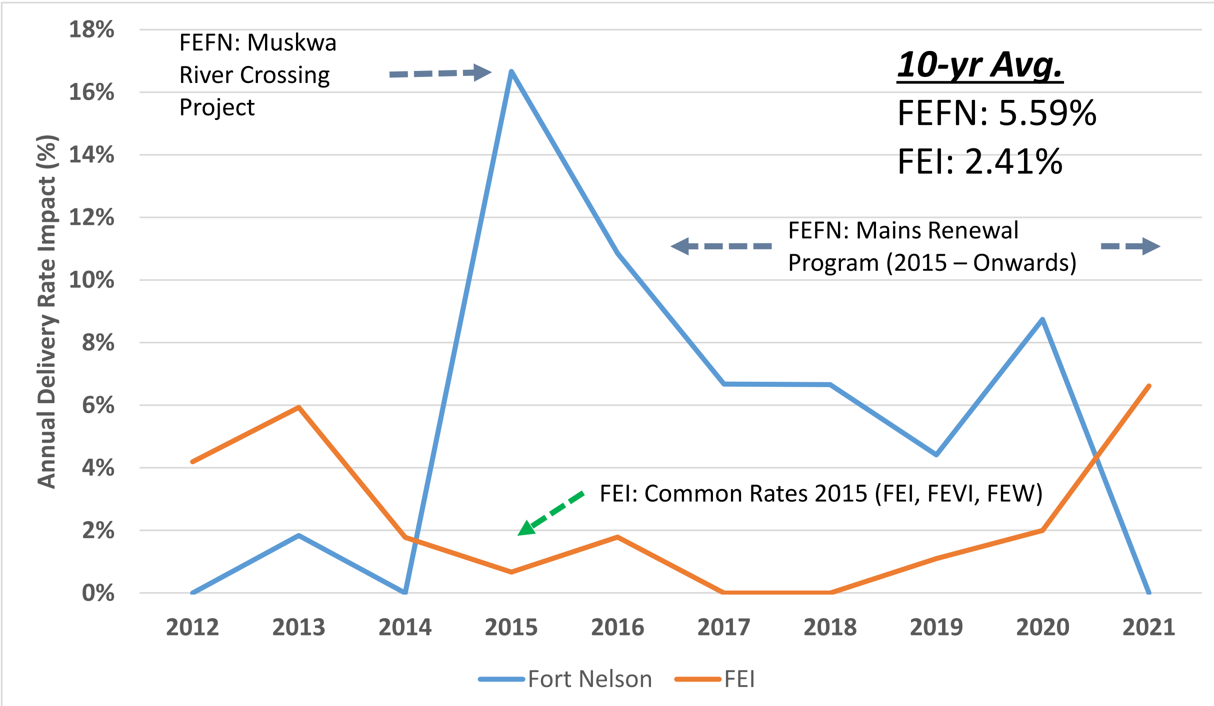


Table 4-7 below further highlights the primary factors that led to the delivery rate increase in FEFN over the last 10 years between 2012 and 2021. Since 2012, FEFN has experienced a 22 percent decrease in natural gas demand (see Section 4.3.2 for further details) while over the same 10-year period, the approved revenue requirement has increased by 35 percent, primarily driven by the required sustainment capital additions discussed in Section 4.3.3 above. Both of these factors significantly impacted FEFN rates, especially with the small customer base in FEFN. For comparison purposes, if FEI were to experience a 137 TJs decrease in demand, the single year impact would be a 0.07 percent reduction in FEI demand. Additionally, an increase of $659 thousand in the revenue requirement, while very impactful to FEFN, represents only 0.75 percent of FEI's 2021 approved delivery margin. Together this would represent a single year delivery rate impact of only 0.15 percent to FEI's non-bypass customers. This comparison indicates why FEFN would benefit from having common delivery rates with FEI, as FEI's much larger service area and customer base would more easily absorb changes in costs and demand and therefore should provide greater delivery rate stability for FEFN customers over the long term.

Table 4-7: Change in FEFN Delivery Margin and Natural Gas Demand from 2012 to 2021 (10 years)

FEFN	2012	2021	Change	% Change
Total Demand (TJ)	630	493	(137)	-22%
Approved Delivery Margin ($000s)	1,874	2,533	659	35%

4.4 GOVERNMENT POLICY SUPPORTING COMMON RATES

The government of BC continues to support a policy for postage stamp rate making. On July 9, 2013, the BC Ministry of Energy and Mines issued a letter to the BCUC in support of FEI's application for common rates. The letter notes the following:

> From a public policy perspective, the Ministry is of the opinion that a common rate resulting from the proposed amalgamation of Fortis BC Energy Utilities will have benefits for all FortisBC Energy customers in British Columbia.
>
> Government policy has been to promote access to energy services on a postage stamp rate basis so that all British Columbians benefit from access to services at the lowest average cost.[28]

The BC Ministry of Energy and Mines has also issued a letter to the BCUC, dated September 17, 2015, stating that postage stamp ratemaking continues to be provincial government policy. In this letter, the Ministry states that:

> Postage stamp rates provide access to services at the lowest average cost, promote investment equality across BC Hydro's service area, streamline regulatory requirements and effective utility management, and minimize potential regional rate impacts as BC Hydro invests in its infrastructure.[29]

Consistent with the above policy, the BCUC has approved a postage stamp rate (common rates) across FEI's service areas, excluding Fort Nelson.

4.5 CONCLUSION

FEI has considered a number of key factors in its determination that now is the appropriate time to move FEFN to common rates. It has become increasingly less beneficial to Fort Nelson customers for FEFN to maintain a separate rate base and rates, and, as was outlined in the FEFN 2019-2020 RRA, it is now negatively impacting commercial customers in terms of that class of customers having higher rates than FEI's other service areas. FEFN's demand has been declining in recent years and is expected to continue to decline. This decline, coupled with ongoing capital expenditure requirements to maintain FEFN's system, has resulted in significant delivery rate volatility over the past ten years and on average greater delivery rate increases for FEFN than for FEI.

With the implementation in 2018 of the rate design changes approved in the RDA Decision, FEFN's rate structure, rate schedules and General Terms and Conditions are now aligned with FEI. The next step is to move FEFN, as the last remaining service area that has a separate rate base and rates from FEI, to common rates. As FEI explains in detail in Section 5 of the Application, the Company explored a variety of options for common rates and is recommending

[28] FEU Common Rates, Amalgamation Rate Design Reconsideration Phase 2, Exhibit C3-1.
[29] BC Hydro 2015 Rate Design Application, Appendix C-1C.

an approach that achieves four key objectives (as described in Section 5) and that is consistent with Dr. Bonbright's rate design principles, government policy regarding postage stamp rates, and past BCUC decisions.

5. REVIEW OF COMMON RATE OPTIONS

5.1 INTRODUCTION

Based on the financial, operational and regulatory/policy context discussed in Section 4, FEI developed the following four key objectives for evaluating its common rates options (Objectives):

- Eliminate the regulatory cost and burden associated with preparing and reviewing the separate regulatory filings required for FEFN, including the costs and time related to the public hearing processes;
- Provide long-term rate stability for FEFN customers;
- Achieve fairness across all FEI service areas by aligning FEFN rates with the rest of FEI's service areas; and
- Mitigate any significant rate increases for FEFN customers that may result from the adoption of common rates.

As FEI explains in this section, the approach that best achieves the Objectives is to implement common delivery and cost of gas rates while maintaining FEFN's midstream (storage & transport) rates at a level consistent with what FEFN is currently being charged, and to phase-in the implementation of common delivery rates for residential customers in order to mitigate the initial rate pressures for that group of customers (i.e., the Proposed Common Rate Option).

In this section, FEI provides a detailed explanation of the Objectives and compares the Proposed Common Rate Option to other options explored. The analysis supports FEI's position that the Proposed Common Rate Option provides the greatest benefits to all of FEI's customers, including those in Fort Nelson.

5.2 COMMON RATES OBJECTIVES

5.2.1 Elimination of Regulatory Burden and Costs

As was described in Section 4 of the Application, delivery, cost of gas and midstream rates have been set separately for FEFN from the date the utility was acquired to the present. This results in a variety of required regulatory filings, including the following:

- Annual or bi-annual revenue requirement applications;
- CPCN applications (while infrequent, separate CPCN applications have been required, such as the 2013 Muskwa River Crossing Project CPCN);
- Gas cost quarterly and annual status reports; and
- Annual reports.

All of these filings are completed by FEI employees across a variety of departments, primarily regulatory, finance and accounting, and gas supply, with input from other operational areas. As there are no employees in these departments that are specifically assigned to Fort Nelson, the effort required to prepare and submit these filings is incremental to the workload already being managed by employees that support the regulatory filings for FEI as a whole. Although a small amount of costs for the work of these employees is allocated to FEFN through the shared services fee, in recent years it has not been representative of the effort required. Moving to common rates would eliminate some or all of the FEFN-specific regulatory filings, depending on the common rate option selected, and would thus streamline certain processes internally through the elimination of separate filing requirements, reporting schedules and other documents.

In general, FEI has been filing two-year revenue requirement applications for FEFN, and these applications have typically undergone a public review process which has, on average, taken approximately six months from filing of the application to issuance of a BCUC decision to complete. This timeframe does not take into account the months of work prior to filing which is necessary for FEI to prepare the application and to undertake consultation with the community. It also does not account for the time and effort required by FEI subsequent to the decision being issued by the BCUC to comply with the decision directives, prepare the compliance filing with updated financial schedules and tariff pages, and implement any rate changes through the customer information system. Thus, even though delivery rates are being set typically for two years through the revenue requirement process, practically speaking, work is required to be undertaken on an almost annual basis.

Beyond freeing up time for FEI employees to focus on other regulatory priorities, common rates (particularly common delivery rates) will eliminate the incremental external regulatory costs (e.g. BCUC costs, external legal fees, public notice costs, and intervener costs) associated with filing separate revenue requirements and CPCNs for FEFN.

The costs of these public review processes are borne solely by Fort Nelson customers through amortization of regulatory proceeding cost deferral accounts and, due to the small customer base, can have a material impact on customer rates. Table 5-1 below provides the total external regulatory proceeding costs and the associated rate impact for the last four revenue requirement applications as well as the most recent CPCN application for the Muskwa River Crossing Project. With the exception of the 2021 Deferral Account Application, the applications underwent a public review process, which included intervener participation with at least one round of information requests. When considered in the context of FEFN's 10-year average delivery rate increase of 5.59 percent as discussed in Section 4.3.4, these incremental regulatory proceeding costs for FEFN have been one of the main contributing factors to the delivery rate increases over the years, contributing an average of 1.78 percent to the average delivery rate increases.

Table 5-1: Historical External Regulatory Proceeding Costs

Application	External Regulatory Costs ($)	Equivalent Delivery Rate Impact (%)*
2021 Deferral Account and RSAM Rider	19,397	0.79%
2019-2020 RRA	49,839	2.02%
2017-2018 RRA	37,567	1.52%
2015-2016 RRA	75,256	3.05%
2013 Muskwa River Crossing Project CPCN	37,328	1.51%
Average Delivery Rate Impact to FEFN (%)		**1.78%**

* Compared to FEFN's approved 2021 delivery margin of $2.533 million.

5.2.2 Long-term Rate Stability

FEI expects common rates will provide increased delivery rate stability for Fort Nelson customers over time. When considering the principle of rate stability in the development of the common rate proposals, FEI has weighed the goal of achieving long-term rate stability for Fort Nelson customers with the goal of minimizing short-term rate pressures. In this section, FEI discusses the objective of providing long-term rate stability for FEFN customers. Please refer to Section 5.2.4 for a discussion on the objective of mitigating short-term rate impacts.

As shown in Figure 4-9 of Section 4.3.4, Fort Nelson customers have experienced high delivery rate volatility historically, with annual delivery rate increases reaching as high as 16.67 percent in 2015. This is due to a variety of factors, including the decline in FEFN's overall demand since 2015, as discussed in Section 4.3.2, and various sustainment and major capital projects entering rate base over the same period, as discussed in Section 4.3.3.

FEI expects moving to common rates will help address this issue given FEI's much broader customer base (over 1 million customers in FEI compared to approximately 2,400 customers in Fort Nelson) to absorb pressures on the revenue requirement created by increased costs or decreased demand. As Figure 4-9 in Section 4.3.4 shows, FEI's delivery rates have been more stable over the past 10 years than FEFN's delivery rates.

With regard to commodity rates, moving to common rates is expected to neither improve nor worsen the rate stability of FEFN's customers in the long-term. The gas supply costs for both FEFN and FEI are forecast quarterly based on a five-day average of forward western Canadian natural gas prices and are reviewed quarterly through reports filed with the BCUC (separate reports are filed for FEI and for FEFN). The changing market conditions of natural gas will affect both FEFN and FEI; therefore, fluctuation in commodity rates occurs for both FEFN and FEI, and there is no trend of either more or less volatility for FEFN than FEI in the commodity rates.

5.2.3 Achieving Fair and Consistent Rates across FEI Service Areas

The main principle behind common rates is one of fairness amongst all of FEI's customers. Under common rates, all customers within a rate class would pay the same rate, regardless of their geographic or service area location.

FEI understands that the main criticism of common rates is that maintaining regional rates may more accurately reflect regional differences in costs. However, this view does not consider the fact that a large portion of FEFN's O&M expenses and revenue requirement are made up of allocated costs from FEI (an average of 54 percent of FEFN's O&M expenses and an average of 24 percent of FEFN's revenue requirement as discussed in Section 4.3.1.1). Therefore, the current regional rates for FEFN are not a true representation of the regional difference in costs between FEFN and FEI.

Within an amalgamated entity (i.e., FEI), common rates are more equitable for all of FEI's customers. It is difficult to justify continuing rate disparity amongst customers for essentially the same service of delivering energy when most customers pay the same rates regardless of location. Moreover, the current differences in rates between FEFN and FEI are the result of corporate history rather than a careful consideration of equities amongst all of FEI's customers combined.

Postage stamp rates are the accepted regulatory approach approved by the BCUC for most other utilities in BC. In fact, as discussed in Section 3, Fort Nelson is the only remaining service area within FEI that is not part of the overall postage stamp (common) rates.

5.2.4 Mitigation of Rate Impacts from Moving to Common Rates

Table 5-2 below shows the current approved 2021 rates for both FEI and FEFN under RS 1 – residential customers, RS 2 – small commercial customers, and RS 3 – large commercial customers. Currently, the delivery rates for FEFN's RS 1 customers are lower than FEI's RS 1 customers, while FEFN's commercial customers currently have higher delivery rates. Additionally, FEFN's midstream rates are significantly less than FEI's midstream rates across all customer classes.

Table 5-2: Comparison of Current 2021 Approved Rates for FEFN and FEI

Rate Schedule		FEFN Approved Rate (2021)	FEI Approved Rate (2021)
Residential			
Rate Schedule 1 Residential Service	Basic Charge ($/Day)	0.3701	0.4216
	Delivery Charge ($/GJ)	4.118	4.915
	Commodity Cost Recovery ($/GJ)	2.999	2.844
	Midstream Charge ($/GJ)	0.043	1.397
Commerical			
Rate Schedule 2 Small Commercial Service (Less than 2,000 GJ)	Basic Charge ($/Day)	1.2151	0.9616
	Delivery Charge ($/GJ)	4.461	3.773
	Commodity Cost Recovery ($/GJ)	2.999	2.844
	Midstream Charge ($/GJ)	0.043	1.373
Rate Schedule 3 Large Commercial Service (Over 2,000 GJ)	Basic Charge ($/Day)	3.6845	4.8026
	Delivery Charge ($/GJ)	3.839	3.279
	Commodity Cost Recovery ($/GJ)	2.999	2.844
	Midstream Charge ($/GJ)	0.036	1.148

Notes to table:

1) Excludes rate riders under the variable delivery charge in $ per GJ.

2) Excludes comparison for RS 5 General Firm Service, RS 6 Natural Gas Vehicle Service, and RS 25 General Firm Transportation Service as there are currently no customers in FEFN under these rate schedules.

FEI is cognizant of the potential short-term rate impact of moving to common rates and has, therefore, balanced the first three objectives described in Section 5.2 with the fourth objective of mitigating adverse rate impacts for FEFN customers. As FEI will explain in Section 5.3 below, a number of the common rate options would result in rate decreases for commercial customers, though FEI acknowledges that under all common rate options residential customers would experience a rate increase of varying magnitudes. As such, FEI also explored the option of phasing-in common rates for residential customers in order to mitigate the impact of rate increases.

5.3 *EVALUATION OF COMMON RATE OPTIONS*

FEI evaluated the following four common rate options:

1. Status quo (i.e., FEFN continues to have a separate rate base and rates);
2. Common delivery rates only;
3. Full transition to common rates (i.e., common delivery, cost of gas, and midstream rates); and

4. Common delivery and cost of gas rates, and amalgamation of FEFN's gas cost portfolios.

In the following sections, FEI provides a qualitative and quantitative assessment of each alternative as well as options for phasing in the rate impacts. As FEI will show, the approach that best achieves the Objectives described in Section 5.2 is to implement common delivery and cost of gas rates while maintaining FEFN's midstream rates at a level consistent with what FEFN is currently being charged, and to phase in the common delivery rate component for residential customers in order to mitigate the initial rate pressures.

5.3.1 Assumptions Used to Evaluate the Common Rate Options

As set out in Sections 2 and 7 of this Application, FEI proposes to implement common rates for FEFN effective January 1, 2023. This is in consideration of the fact that FEI does not anticipate a BCUC decision on the Proposed Common Rate Option to be reached prior to the end of 2021. As such, an implementation of common rates for FEFN on January 1, 2023 will enable a more coherent transition as it coincides with FEI's rate change dates for delivery, cost of gas and midstream charges.

Since FEI proposes to implement common rates for FEFN in 2023, comparison of bill impacts for FEFN customers between the different common rate options will be based on the forecast 2023 rates of FEFN and FEI. The following assumptions have been used to evaluate the bill impacts for FEFN customers in 2023:

- The starting point for determining the bill impacts for FEFN customers in 2023 is FEFN's 2022 rates. For 2022, the forecast FEFN delivery rate increase is 3.41 percent, as detailed in Section 8 of this Application. This forecast delivery rate increase applies to the standalone FEFN service area.
- For 2023, FEI forecasts an FEFN delivery rate increase of 9.68 percent from the forecast 2022 delivery rates, assuming FEFN continues to have separate delivery rates from FEI. The forecast for FEFN 2023 delivery rates is indicative only and is based on the demand forecast and capital additions forecast for FEFN discussed in Section 4.3.2 and Section 4.3.3, respectively, and a forecast of O&M expenses and other costs in 2023.
- In order to estimate the bill impact to FEFN's customers in 2023 due to the adoption of common delivery rates, it is necessary to estimate FEI's delivery rates in 2023. To do so, FEI used the applied for 2022 delivery rate increase of 8.07 percent from FEI's Annual Review for 2022 Delivery Rates[30] as the starting point and has conservatively assumed the same delivery rate increase in 2023 (i.e., 8.07 percent).[31]

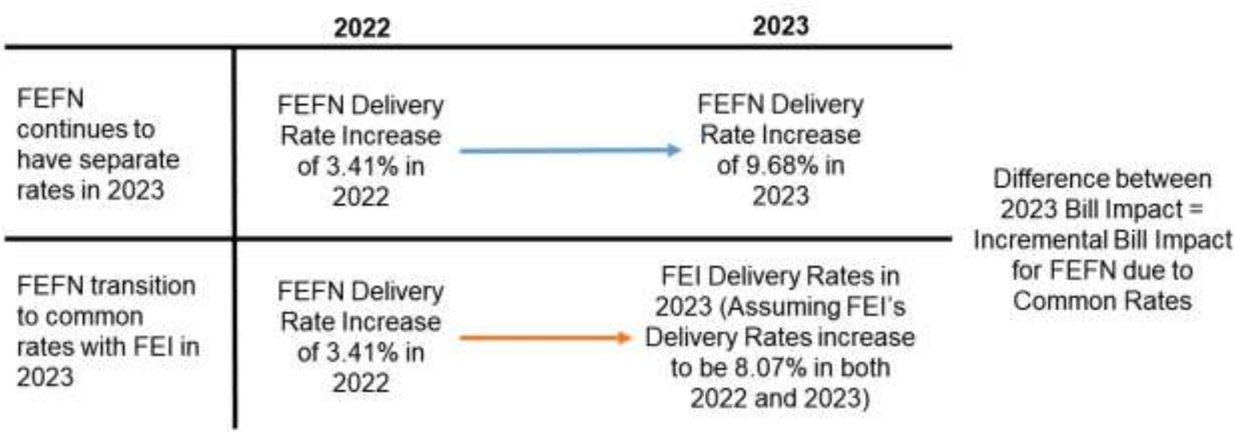
[30] Filed with the BCUC on July 30, 2021.

[31] FEI notes the 8.07 percent rate increase for 2023 is a conservative estimate that would also account for the inclusion of FEFN in FEI's revenue requirement. Based on FEFN's 2022 forecast delivery margin of $2.517 million, the estimated rate impact to FEI's 2022 forecast non-bypass delivery margin is small at 0.002 percent.

- For the cost of gas rates and midstream rates, FEI has based 2022 gas costs for FEFN and FEI on the 2021 Second Quarter Gas Cost Report filed with the BCUC on June 2, 2021, and has assumed no change in gas costs for 2023.

The bill impact to FEFN customers due to the adoption of common rates is calculated based on the difference between FEFN's 2023 rates (assuming FEFN continues to have separate rates from FEI) and FEI's 2023 rates. Figure 5-1 below shows the different rate pathways for FEFN which set the basis of comparison between the different common rates options.

Figure 5-1: FEFN Status Quo and Common Rate Pathways for 2023



5.3.2 Option 1 – Status Quo

Under the status quo option, FEFN would continue to have a separate rate base and set all components of its rates (delivery, cost of gas and midstream) separately from FEI.

Maintaining the status quo is not recommended, as it does not address the issues described in Section 4 regarding the impact on FEFN delivery rates of declining demand and continuing capital investment requirements, which contribute to FEFN's higher level of delivery rate volatility. Further, the status quo option does not eliminate or reduce any of the regulatory burden and costs associated with FEFN regulatory filings, and it does not address fairness and consistency of rate treatment between FEFN and the remainder of FEI's customers.

Under the status quo option, Figure 5-2 below shows the actual delivery rate increases for FEFN between 2012 and 2021, and the forecast increases for 2022 and 2023 as mentioned above. The historical delivery rate volatility for FEFN continues into 2023 on a forecast basis, and the average delivery rate increase from 2012 to 2023 is increased to 5.73 percent (compared to the average 5.59 percent increase from 2012 to 2021 shown in Figure 4-9 in Section 4.3.4).

Figure 5-2: FEFN Delivery Rate Increase: Actual 2012 – 2021; Forecast 2022 and 2023

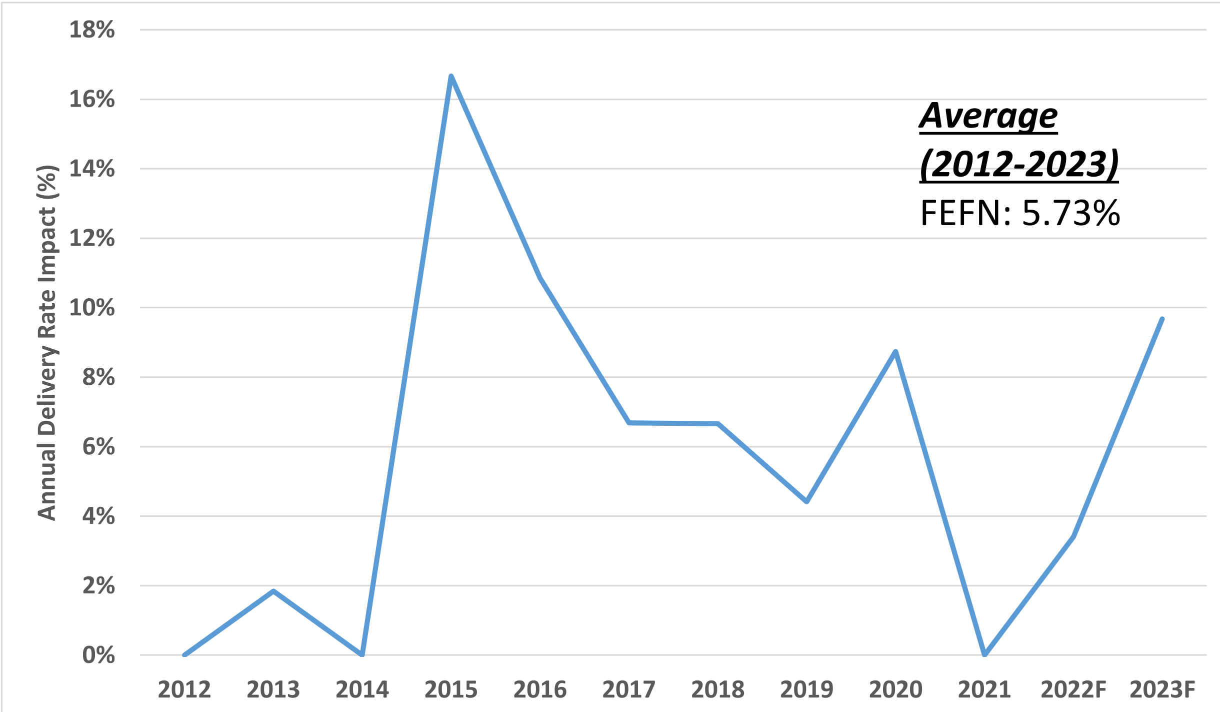


Table 5-3 below shows the estimated bill impact for an average residential and commercial customer in 2022 and 2023 for the status quo option.

Table 5-3: Estimated Average Bill Impact for FEFN Customers in 2022 and 2023 under Option 1

FEFN Customers	Avg. UPC (GJ)	Bill Impact in 2022 ($)	Bill Impact in 2023 ($)
Residential RS 1	125	22	63
Small Commerical RS 2	335	65	191
Large Commerical RS 3	6,375	835	2,486

Table 5-4 below summarizes Option 1 – Status Quo in accordance with the Objectives:

Table 5-4: Assessment of Option 1 Based on Common Rates Objectives

Objectives	Option 1 – Status Quo
1) Eliminate regulatory filings and costs	• No change in terms of regulatory filings and costs on annual basis • FEI estimates 5.5 FEFN regulatory filings per year (i.e., FEFN's RRA once every two years, four FEFN gas cost reports per year, and one Annual Report for FEFN)
2) Provide long-term rate stability for FEFN customers	• FEFN will continue to experience volatility in rates due it its small customer base with a continued decline in demand and continued requirements for sustainment capital

Objectives	Option 1 – Status Quo
3) Achieve fairness across all FEI service areas, including FEFN	• Continued disparity between FEI and FEFN customers
4) Mitigating rate impact to FEFN customers	• Bill impacts for all rate classes in 2023 (i.e., the proposed effective date for common rates): • Increase of ***$63*** (RS 1) for average residential customers in 2023 • Increase of ***$191*** for average small commercial (RS 2) customers in 2023 • Increase of ***$2,486*** for average large commercial (RS 3) customers in 2023

The other three common rate options are evaluated below, including a comparison of the bill impacts of each option to the 2023 estimated status quo bill impacts shown above. Since FEI is proposing common rates to be effective January 1, 2023, all comparisons between status quo and the common rate options are based on the rate impact in 2023.

5.3.3 Option 2 – Common Delivery Rates Only

Under the option of common delivery rates only, FEFN would no longer have a separate rate base, which would eliminate the requirement to file separate revenue requirement applications as well as annual reports for FEFN. However, FEFN would maintain its own cost of gas and midstream charges which are reviewed quarterly by the BCUC through FEFN's quarterly gas cost reports. Thus, this option partially achieves the objective of eliminating regulatory costs and burden. Further, as described below, this option achieves the objectives of long-term rate stability and minimizing the short-term rate impact of moving to common rates, but only partially addresses the objective of fairness amongst all customers.

Table 5-5 below compares the estimated delivery rates in 2023 for FEFN between a move to common delivery rates and status quo (rates highlighted in green represent the components that would be impacted by moving to common rates with FEI).

Table 5-5: Estimated 2023 Fort Nelson Rates under Option 2 Compared to Status Quo

Rate Schedule		FEFN Option 1 - Status Quo (2023 Estimated)	FEFN Option 2 - Common Delivery Rate (2023 Estimated)
Residential			
Rate Schedule 1 Residential Service	**Basic Charge ($/Day)**	**0.3701**	**0.4216**
	Delivery Charge ($/GJ)	**4.798**	**6.038**
	Commodity Cost Recovery ($/GJ)	2.999	2.999
	Midstream Charge ($/GJ)	0.051	0.051
Commerical			
Rate Schedule 2 Small Commercial Service (Less than 2,000 GJ)	**Basic Charge ($/Day)**	**1.2151**	**0.9616**
	Delivery Charge ($/GJ)	**5.223**	**4.588**
	Commodity Cost Recovery ($/GJ)	2.999	2.999
	Midstream Charge ($/GJ)	0.052	0.052
Rate Schedule 3 Large Commercial Service (Over 2,000 GJ)	**Basic Charge ($/Day)**	**3.6845**	**4.8026**
	Delivery Charge ($/GJ)	**4.360**	**3.910**
	Commodity Cost Recovery ($/GJ)	2.999	2.999
	Midstream Charge ($/GJ)	0.043	0.043

Table 5-6 compares the estimated bill impact in 2023 for the average FEFN customer of moving to common delivery rates against the status quo.

Table 5-6: Estimated 2023 Average Bill Impact under Option 2 Compared to Status Quo

	Avg. UPC (GJ)	FEFN Option 1 - Status Quo Bill Impact in 2023 ($)	FEFN Option 2 - Common Delivery Rate Bill Impact in 2023 ($)	Incremental Bill Impact in 2023 due to Common Rates Only ($)
Residential RS 1	125	63	237	174
Small Commerical RS 2	335	191	(115)	(305)
Large Commerical RS 3	6,375	2,486	26	(2,460)

As shown in the above table, if FEFN transitions to common delivery rates with FEI in 2023, the average FEFN residential customer will see an estimated incremental bill impact of $174 in that year, while small and large commercial customers will experience savings of approximately $305 and $2,460, respectively, in that year.

Table 5-7 below summarizes Option 2 (Common Delivery Rates Only) in accordance with the Objectives:

Table 5-7: Assessment of Option 2 Based on Common Rates Objectives

Objectives	Option 2 – Common Delivery Rates Only
1) Eliminate regulatory filings and costs	• Eliminates the need to file RRAs (average RRA cost is $45.5 thousand from 2015 to 2021, as shown in Table 5-1) and Annual Reports • FEI estimates 4 FEFN regulatory filings per year (i.e., four FEFN gas cost reports per year)
2) Provide long-term rate stability for FEFN customers	• Common delivery rates with FEI will provide long-term rate stability for FEFN customers
3) Achieve fairness across all FEI service areas, including FEFN	• Eliminates delivery rate disparity only between FEI and FEFN • Disparity in cost of gas and storage and transport rates remains between FEI and FEFN customers
4) Mitigating rate impact to FEFN customers	• Incremental bill increase for residential customers if transition in 2023 but savings for commercial customers • Incremental bill impact of ***$174*** for average residential (RS 1) customers in 2023 • Incremental bill impact of ***($305)*** for average small commercial (RS 2) customers in 2023 • Incremental bill impact of ***($2,460)*** for average large commercial (RS 3) customers in 2023

5.3.4 Option 3 – Full Transition of Common Delivery, Cost of Gas, and Storage and Transport Rates

Under the option of full common rates, FEFN would fully transition to FEI's delivery, cost of gas, and midstream rates. As described below, this option achieves some of the identified Objectives, including the elimination of regulatory costs and burden and fairness amongst all customers; however, the rate impact for FEFN customers associated with this option is high.

In order to implement common gas cost recovery rates (cost of gas and midstream) for this option, FEI would amalgamate FEFN's and FEI's gas cost supply portfolios through FEI's existing Midstream Cost Reconciliation Account (MCRA)[32].

Table 5-8 below compares the estimated delivery, cost of gas and midstream rate components in 2023 for FEFN between a move to full common rates and status quo.

[32] As discussed in Section 4.3.1.2, the natural gas purchases for FEFN are shaped to the relative level of seasonal consumption, similar to how FEI currently captures the costs for seasonal shaping in FEI's natural gas supply in the MCRA. In contrast, FEI's existing CCRA captures the volumetric purchases for the baseload over 365 days per year.

Table 5-8: Estimated 2023 Fort Nelson Rates under Option 3 Compared to Status Quo

Rate Schedule		FEFN Option 1 - Status Quo (2023 Estimated)	FEFN Option 3 - Full Common Rate (2023 Estimated)
Residential			
Rate Schedule 1 Residential Service	Basic Charge ($/Day)	0.3701	0.4216
	Delivery Charge ($/GJ)	4.798	6.038
	Commodity Cost Recovery ($/GJ)	2.999	2.844
	Midstream Charge ($/GJ)	0.051	1.449
Commerical			
Rate Schedule 2 Small Commercial Service (Less than 2,000 GJ)	Basic Charge ($/Day)	1.2151	0.9616
	Delivery Charge ($/GJ)	5.223	4.588
	Commodity Cost Recovery ($/GJ)	2.999	2.844
	Midstream Charge ($/GJ)	0.052	1.472
Rate Schedule 3 Large Commercial Service (Over 2,000 GJ)	Basic Charge ($/Day)	3.6845	4.8026
	Delivery Charge ($/GJ)	4.360	3.910
	Commodity Cost Recovery ($/GJ)	2.999	2.844
	Midstream Charge ($/GJ)	0.043	1.232

Table 5-9 below compares the estimated bill impact in 2023 for the average FEFN customer if FEFN transitions to full common rates with FEI against the status quo.

Table 5-9: Estimated Average 2023 Bill Impact under Option 3 Compared to Status Quo

	Avg. UPC (GJ)	FEFN Option 1 - Status Quo Bill Impact in 2023 ($)	FEFN Option 3 - Full Common Rate Bill Impact in 2023 ($)	Incremental Bill Impact in 2023 due to Common Rates Only ($)
Residential RS 1	125	63	392	329
Small Commerical RS 2	335	191	309	118
Large Commerical RS 3	6,375	2,486	6,618	4,131

As shown in the table above, if FEFN transitions to full common rates with FEI in 2023, the average residential customer in FEFN will have an incremental bill impact estimated to be $329 in that year due to common rates only. The estimated incremental bill impact for small and large commercial customers is $118 and $4,131, respectively, in that year.

Table 5-10 below summarizes Option 3 (Full Common Rates) in accordance with the Objectives.

Table 5-10: Assessment of Option 3 Based on Common Rates Objectives

Objectives	Option 3 – Full Common Rates
1) Eliminate regulatory filings and costs	• Eliminates all separate regulatory filings for FEFN including RRAs, annual reports, and quarterly gas cost reports
2) Provide long-term rate stability for FEFN customers	• Full Common rates with FEI will provide long-term rate stability for FEFN customers

Objectives	Option 3 – Full Common Rates
3) Achieve fairness across all FEI service areas, including FEFN	• Eliminates all disparity in rates between customers in FEI and FEFN
4) Mitigating rate impact to FEFN customers	• Incremental bill increase for all rate classes if transition in 2023 • Incremental bill impact of ***$329*** for average residential (RS 1) customers in 2023 • Incremental bill impact of ***$118*** for average small commercial (RS 2) customers in 2023 • Incremental bill impact of ***$4,131*** for average large commercial (RS 3) customers in 2023

As the above analysis shows, a move to full common rates will have a significant negative bill impact for FEFN customers in the year of transition, primarily due to the current disparity in FEFN's midstream rates compared to FEI's midstream rates. The unitized costs related to FEFN's current gas supply portfolio are significantly lower than those for FEI's current gas supply portfolio. As described in Section 4.3.1.2, FEFN's natural gas supply and load balancing requirements are currently met through the use of unique commodity supply arrangements and the relatively low cost for the short-haul transportation service; whereas, FEI holds considerable storage and transportation resources in its midstream portfolio in order to meet the seasonal and daily natural gas supply and load balancing requirements for the Mainland and Vancouver Island service area sales customers.

In consideration of the above factors, FEI developed a fourth option, which includes a move to common delivery and cost of gas rates while maintaining FEFN's midstream rate at a level similar to the existing rate.

5.3.5 Option 4 – Common Delivery and Cost of Gas Rates, and Amalgamation of FEFN's Gas Cost Portfolios

Under Option 4, FEI proposes to move FEFN to common delivery and cost of gas rates while maintaining FEFN's midstream (storage & transport) rates at a level consistent with what FEFN is currently being charged. This approach will achieve the benefits of common delivery rates discussed previously, and transition FEFN customers to a common cost of gas rate with FEI without the significant negative bill impact to FEFN customers seen in Option 3 (Full Common Rates).

In order to transition FEFN to a common cost of gas rate with FEI while maintaining FEFN's midstream rates at a level similar to FEFN's existing midstream rates, changes to the accounting treatment of FEFN's gas costs portfolio will be required. In the following subsections, FEI describes the changes in the accounting treatment to FEFN's gas costs portfolio necessary for this common rate option, and the rate impacts to FEI and FEFN customers from this option.

5.3.5.1 Changes to Accounting Treatment required for FEFN's Natural Gas Supply Costs under Option 4

In order to transition FEFN to a common cost of gas rate with FEI while maintaining FEFN's midstream rate at a similar level to what FEFN customers currently pay, FEI proposes to amalgamate the costs of FEI and FEFN's natural gas supply portfolios through FEI's existing MCRA, as follows, with the same effective date of January 1, 2023:

1. Amalgamate the cost of FEFN's natural gas supply portfolio with the cost of FEI's natural gas supply portfolio by transferring the closing balance (assuming December 31, 2022) of FEFN's existing GCRA to FEI's existing MCRA as an opening balance adjustment, effective January 1, 2023;
2. Eliminate FEFN's GCRA;
3. Starting January 1, 2023, capture all of FEFN's natural gas supply portfolio costs, including FEFN's transportation costs, in FEI's MCRA;
4. Starting January 1, 2023, offer FEFN customers the same cost of gas rate as FEI, with the recoveries of the cost of gas rate from FEFN customers captured in FEI's MCRA; and
5. Starting January 1, 2023, set FEFN's midstream rates based on 5 percent of FEI's midstream rates which are a level similar to FEFN's existing midstream rates.

FEI notes that this accounting treatment is consistent with the amalgamation of Revelstoke's propane supply portfolio costs into FEI's MCRA, which was approved by the BCUC as part of the Revelstoke Propane Portfolio Cost Amalgamation Decision and Order G-245-20. The only difference between the treatment approved for Revelstoke and the proposed treatment for FEFN is that Revestoke's midstream rates are now equal to FEI's (i.e., full common midstream rates), while for FEFN, under this proposed Option 4, the midstream rates will be set based on 5 percent of FEI's midstream rates in order to maintain FEFN's midstream rates at amounts close to the current rates, thus minimizing the rate increase for FEFN associated with common rates.

Similar to Revelstoke, FEI proposes to capture FEFN's natural gas supply portfolio costs in FEI's existing MCRA. This is because, as discussed in Section 4.3.1.2, the natural gas purchases for FEFN are shaped to the relative level of seasonal consumption, similar to how FEI currently captures the costs for seasonal shaping in FEI's natural gas supply in the MCRA. In contrast, FEI's existing CCRA captures the volumetric purchases for the baseload over 365 days per year.

FEI believes setting FEFN's midstream rates at 5 percent of FEI's midstream rates is appropriate. FEI based the 5 percent on a number of factors, including the current difference between FEI and FEFN's midstream rates, and the average difference in midstream rates historically. The current difference in percentage between FEI and FEFN is approximately three percent, while the average difference in percentage between the cumulative FEFN midstream recovery requirement and the cumulative FEFN midstream recovery at FEI's midstream rates from 2011 to 2020 (assuming FEFN rates are based on FEI's midstream rates since 2011) is approximately seven percent. Based on these two considerations, FEI has determined that setting FEFN's midstream rates at five percent (i.e., the average between three and seven percent) of FEI's midstream rates is the most appropriate balance between the current difference and the average historical difference.

Table 5-11 below provides an illustration of setting FEFN's midstream rates based on a five percent multiplier of FEI's midstream rate. FEI notes that, as mentioned in Section 5.3.1 above, the estimated 2023 gas costs for FEI and FEFN are based on the 2021 Second Quarter Gas Cost Report filed with the BCUC on June 2, 2021, assuming no change in gas costs between 2022 and 2023. Please refer to Appendix B for an example of the five percent midstream (storage & transport including MCRA rider) rate calculation and rate-setting mechanism within the MCRA under this proposed amalgamated gas cost portfolio for FEI and FEFN.

Table 5-11: Illustration of Common Cost of Gas Rate for FEFN under Option 4

Line	Particular	Reference	FEI		Multipler	FEFN (Option 4 - Common Delivery and Cost of Gas with Midstream @ 5% of FEI)
1	***Rate Schedule 1 - January 1, 2023***					
2	Commodity Related Charges					
3	Cost of Gas ($/GJ)	FEI: 2021 Q2 Gas Cost Report; FEFN: Equals to FEI	2.844			2.844
4	Midstream Rate ($/GJ)	FEI: Appendix A-2, Line 45 + 50, Col 2; FEFN: Line 4 x Multipler	1.454	x	0.050	0.073
5	Total Commodity Related Charges ($/GJ)	Line 3 + Line 4	4.298			2.917
6						
7	***Rate Schedule 2 - January 1, 2023***					
8	Commodity Related Charges					
9	Cost of Gas ($/GJ)	FEI: 2021 Q2 Gas Cost Report; FEFN: Equals to FEI	2.844			2.844
10	Midstream Rate ($/GJ)	FEI: Appendix A-2, Line 45 + 50, Col 3; FEFN: Line 10 x Multipler	1.477	x	0.050	0.074
11	Total Commodity Related Charges ($/GJ)	Line 9 + Line 10	4.321			2.918
12						
13	***Rate Schedule 3 - January 1, 2023***					
14	Commodity Related Charges					
15	Cost of Gas ($/GJ)	FEI: 2021 Q2 Gas Cost Report; FEFN: Equals to FEI	2.844			2.844
16	Midstream Rate ($/GJ)	FEI: Appendix A-2, Line 45 + 50, Col 4; FEFN: Line 16 x Multipler	1.234	x	0.050	0.062
17	Total Commodity Related Charges ($/GJ)	Line 15 + Line 16	4.078			2.906

Currently, variations in FEFN's cost of gas are captured in the GCRA and are recovered from FEFN customers through amortization of the GCRA balance. Under the proposed common rate Option 4, variances in FEFN's cost of gas, which can be in either a surplus or deficiency position in any given year, will be recorded in FEI's MCRA and recovered from all customers (i.e., both FEI and FEFN customers) through the midstream rates. However, as previously explained, FEFN customers will only be allocated five percent of the midstream costs, including amortization of MCRA balances, as their midstream rates. FEI expects this variance to be small and have a negligible impact (positive or negative) on FEI's customers due to FEFN's small customer base and quantity of gas consumed.

Table 5-12 below illustrates this variance in FEFN's cost of gas using historical gas costs from 2011 to 2020, assuming FEFN had been on a common cost of gas rate with FEI and its midstream rates had been set at 5 percent of FEI's midstream rates since 2011. The results show that if this accounting treatment and rate-setting mechanism had been implemented in 2011, the total variance over the last 10 years would be approximately $97 thousand (or 0.64 percent), which is equivalent to a total average midstream rate impact of $0.002 per GJ over the 10-year period. For the average FEI residential customer consuming 90 GJs per year, the cumulative impact due to this variance is approximately $0.15 over a 10-year period.

Table 5-12: Illustration of FEFN Gas Cost Variance due to Common Cost of Gas Rate and 5% Storage & Transport Rate Setting Mechanism

Year	FEFN Gas Cost Recovery Variance (FEFN Gas Cost - FEFN Common Commodity & 5% Midstream) ($000s)	FEI Total MCRA Costs (incl. MCRA Amortization) ($000s)	FEI Midstream Demand (TJ)	% FEFN Gas Cost Recovery Variance to FEI Total MCRA Costs	Average Midstream Rate Impact to FEI's Customer ($/GJ)	$ Impact to Avg. FEI Residential Customer (90 GJ/yr)
2011	$ 207	$ 159,800	114,533	0.13%	$ 0.002	$ 0.16
2012	246	146,276	112,961	0.17%	0.002	0.20
2013	200	127,569	112,820	0.16%	0.002	0.16
2014	(28)	147,127	114,139	-0.02%	(0.000)	(0.02)
2015	109	155,855	121,383	0.07%	0.001	0.08
2016	(263)	108,253	121,180	-0.24%	(0.002)	(0.20)
2017	(5)	98,665	123,733	0.00%	(0.000)	(0.00)
2018	(11)	99,687	134,485	-0.01%	(0.000)	(0.01)
2019	(123)	193,000	135,901	-0.06%	(0.001)	(0.08)
2020	(236)	140,614	149,451	-0.17%	(0.002)	(0.14)
Total	**$ 97**			**0.02%**	**$ 0.002**	**$ 0.15**

FEI also notes that, consistent with Revelstoke, the proposed change involves only the accounting treatment of FEFN's natural gas supply portfolio costs. It does not change how the physical natural gas supply for FEFN is planned and managed. FEI will continue to manage FEFN's natural gas supply separately for the purposes of contracting balance and mitigation as described in Section 4.3.1.2. However, consistent with Revelstoke, FEFN's natural gas cost portfolio will be combined into a single quarterly gas cost report for all of FEI following the amalgamation of the natural gas cost portfolios between FEI and FEFN, as the costs will be managed as one total portfolio.

5.3.5.2 FEFN Customer Bill Impact under Option 4

Table 5-13 below compares the estimated rates in 2023 for FEFN between Option 4 (common delivery and cost of gas rates with the midstream rates set at five percent of FEI's midstream rates) and the status quo (rates highlighted in green represent the components that would be impacted by moving to common rates with FEI).

Table 5-13: Estimated 2023 Fort Nelson Rates under Option 4 Compared to Status Quo

Rate Schedule		FEFN Option 1 - Status Quo (2023 Estimated)	FEFN Option 4 - Common Delivery and Cost of Gas Rate with Midstream @ 5% of FEI (2023 Estimated)
Residential			
Rate Schedule 1 Residential Service	**Basic Charge ($/Day)**	**0.3701**	**0.4216**
	Delivery Charge ($/GJ)	**4.798**	**6.038**
	Commodity Cost Recovery ($/GJ)	**2.999**	**2.844**
	Midstream Charge ($/GJ)	0.051	0.073
Commerical			
Rate Schedule 2 Small Commercial Service (Less than 2,000 GJ)	**Basic Charge ($/Day)**	**1.2151**	**0.9616**
	Delivery Charge ($/GJ)	**5.223**	**4.588**
	Commodity Cost Recovery ($/GJ)	**2.999**	**2.844**
	Midstream Charge ($/GJ)	0.052	0.074
Rate Schedule 3 Large Commercial Service (Over 2,000 GJ)	**Basic Charge ($/Day)**	**3.6845**	**4.8026**
	Delivery Charge ($/GJ)	**4.360**	**3.910**
	Commodity Cost Recovery ($/GJ)	**2.999**	**2.844**
	Midstream Charge ($/GJ)	0.043	0.062

Table 5-14 below compares the estimated bill impact in 2023 for the average FEFN customer under Option 4 against the status quo.

Table 5-14: Estimated Average 2023 Bill Impact under Option 4 Compared to Status Quo

	Avg. UPC (GJ)	FEFN Option 1 - Status Quo Bill Impact in 2023 ($)	FEFN Option 4 - Common Delivery and Cost of Gas Rate with Midstream @ 5% of FEI Bill Impact in 2023 ($)	Incremental Bill Impact in 2023 due to Common Rates Only ($)
Residential RS 1	125	63	220	157
Small Commerical RS 2	335	191	(159)	(350)
Large Commerical RS 3	6,375	2,486	(841)	(3,327)

As shown in the table above, under Option 4, the average residential customer in FEFN will have an incremental bill impact estimated to be $157 that year due to common rates ($174 for the delivery portion, offset by savings of $17 from the commodity and midstream portion). For small and large commercial customers, the transition will result in estimated savings of $350 and $3,327, respectively, in that year. FEI notes that although there is a small increase in FEFN's midstream rate, it represents an approximate annual increase of only $2.71 for the average residential customers in FEFN.

Table 5-15 below summarizes Option 4 in accordance with the Objectives of this Application:

Table 5-15: Assessment of Option 4 Based on Common Rates Objectives

Objectives	Option 4 – Common Delivery Rates and Cost of Gas Rates with Midstream Rates set at 5 percent of FEI
1) Eliminate regulatory filings and costs	• Eliminates all separate regulatory filings for FEFN including RRAs, annual reports, and quarterly gas cost reports
2) Provide long-term rate stability for FEFN customers	• Common delivery rates with FEI will provide long-term rate stability for FEFN customers
3) Achieve fairness across all FEI service areas, including FEFN	• Eliminates disparity in delivery and cost of gas rates between FEI and FEFN customers • Disparity in storage and transport rates remains between FEI and FEFN customers
4) Mitigating rate impact to FEFN customers	• Incremental bill increase for residential customers if transition in 2023 but savings for commercial customers • Incremental bill impact of ***$157*** for average residential (RS 1) customers in 2023 • Incremental bill impact of ***($350)*** for average small commercial (RS 2) customers in 2023 • Incremental bill impact of ***($3,327)*** for average large commercial (RS 3) customers in 2023

5.4 OPTION 4 BEST ACHIEVES THE OBJECTIVES

Table 5-16 below summarizes the four options and weighs each option against the Objectives. Each option is scored against each objective, with each objective weighted equally. The score for objectives 1 to 3 is based on a score of 2 for Green, 1 for Yellow, and 0 for Red. For objective 4 – mitigating the rate impact to FEFN customers of adopting common rates, the scoring is based on the following: a score of 2 (Green) indicates that savings are achieved for some/all customers classes; a score of 1 (Yellow) indicates a small impact (relative to the worst case) for all customer classes; and a score of 0 (Red) represents the option with the largest negative impact to all customer classes.

Table 5-16: Evaluation of All 4 Options of Common Rates for FEFN

Objectives	Option 1 – Status Quo	Option 2 – Common Delivery Only	Option 3 – Full Common Rates	Option 4 – Common Delivery and Cost of Gas with Midstream @ 5% of FEI
1) Eliminate regulatory filings and costs	• No. There is no reduction in regulatory filings per year – stays at: 5.5 • FEFN will continue to bear the full cost of regulatory proceedings.	• Partial. Number of regulatory filings per year reduced to: 4 • Elimination of regulatory costs for RRA and CPCN proceedings.	• Yes. Number of Regulatory filings per year: 0	• Yes. Number of regulatory filings per year: 0

Objectives	Option 1 – Status Quo	Option 2 – Common Delivery Only	Option 3 – Full Common Rates	Option 4 – Common Delivery and Cost of Gas with Midstream @ 5% of FEI
2) Provide long-term rate stability for FEFN customers	• No	• Yes	• Yes	• Yes
3) Achieve fairness across all FEI service areas, including FEFN	• No	• Partial. Fairness achieved for delivery rates only.	• Yes	• Most components. Fairness achieved for delivery and cost of gas, and accounting of midstream costs is now aligned with FEI (though FEFN is only paying 5% of the midstream costs).
4) Mitigating rate impact to FEFN customers	• Bill Impact in 2023: RS 1 = $63 RS 2 = $191 RS 3 = $2,486	• Bill Impact in 2023: RS 1 = $237 RS 2 = ($115) RS 3 = $26 • Incremental to Status Quo: RS 1 = $174 RS 2 = ($305) RS 3 = ($2,460)	• Bill Impact in 2023: RS 1 = $392 RS 2 = $309 RS 3 = $6,618 • Incremental to Status Quo: RS 1 = $329 RS 2 = $118 RS 3 = $4,131	• Bill Impact in 2023: RS 1 = $220 RS 2 = ($159) RS 3 = ($841) • Incremental to Status Quo: RS 1 = $157 RS 2 = ($350) RS 3 = ($3,327)
Total Score (2 for Green, 1 for Yellow, 0 for Red)	**1**	**6**	**6**	**8**

Based on the assessment in the above table, Option 4 – Common Delivery and Cost of Gas Rates with the Midstream Rates set at 5 percent of FEI's MCRA is the recommended option, as it best meets the Objectives.

Accordingly, FEI is requesting approval to implement this common rate option effective January 1, 2023 (Proposed Common Rate Option). Under this option, small and large commercial customers will benefit immediately with savings in their bills while residential customers will see a bill increase. FEI proposes to mitigate the bill increase to residential customers through a phase-in approach, as described in the following section.

5.5 PHASE-IN OF COMMON DELIVERY RATES FOR FEFN RESIDENTIAL CUSTOMERS

Under the Proposed Common Rate Option, FEFN residential customers will see an increase in their bills in 2023 while commercial customers will see a savings, primarily due to the impact of the transition to common delivery rates. FEI seeks to mitigate this bill impact to FEFN's residential customers and, therefore, proposes to phase in the transition of common delivery rates for FEFN's residential customers over a 10-year period through a phase-in delivery rate rider. FEI notes the phase-in rider will apply to residential customers only while FEFN's commercial customers will fully transition to common delivery rates in 2023. FEI also notes that the phase-in is only applicable to delivery rates and not the cost of gas rates since FEI expects there will be a minimal bill impact (positive or negative) associated with the move to common cost of gas rates.

Table 5-17 below provides a forecast schedule of the phase-in credit rate rider proposed for FEFN residential customers over a 10-year period, which is calculated based on the initial difference of delivery margin in 2023 for FEFN residential customers, estimated to be $319 thousand[33], and decreases each year until it reaches zero (Line 5). FEI also proposes to include the approved 2021 FEFN surplus, which is forecast to be $94 thousand at December 31, 2022[34], to further reduce the annual bill impact to FEFN residential customers by increasing the phase-in credit rate rider over the same 10-year period (Line 6). The total FEFN residential phase-in rider for common rates is shown on Line 7 of Table 5-17 below. The table below also provides the continuity of the FEFN Residential Common Rate Phase-in deferral account (Line 12 to 19) used to administer the proposed credit rate rider, with the amortization of this deferral account to FEI's non-bypass customers through delivery rates over the 10-year period (Line 18). FEI notes the forecast phase-in credit rate riders over the 10-year period shown in the table below are calculated based on the 2023 residential demand forecast as shown in Section 4.3.2.1. FEI proposes to update the actual phase-in rate rider each year in FEI's annual review with updated forecasts of FEFN residential customer demand and the actual-to-date balance of the deferral account each year. Please refer to Section 7.1.4.4 for more detail about this proposed FEFN Residential Common Rate Phase-in deferral account.

As shown in Table 5-17, the cumulative amortization to FEI's delivery rates over the 10-year period is approximately $1,282 thousand, which is equivalent to a one-time delivery rate impact of approximately 0.15 percent (Line 19) when compared to FEI's approved 2021 delivery rates.

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[33] Calculated based on the forecast difference of basic charge and delivery rates in 2023 between FEFN and FEI for residential customers as shown in Table 5-13, and the forecast FEFN residential demand of 229.7 TJs in 2023 shown in Figure 4-2 in Section 4.3.2.1 as well as the forecast FEFN residential customer count of 1,841 in 2023 shown in Figure 4-5 of Section 4.3.2.2. E.g. ($0.4216/day - $0.3701/day) x 365.25 days x 1,841 / 1000 + ($6.038/GJ - $4.798/GJ) x 229.7 TJ = $319 thousand.

[34] The forecast 2022 ending after-tax balance in the deferral account for the 2021 revenue surplus is $94 thousand. This balance is comprised of the approved 2021 revenue surplus of $132 thousand, less FEI's external legal costs and BCUC direct costs related to the review of the application which total $14 thousand, less income taxes of $32 thousand, plus carrying charges accrued on the deferral account balance of $3 thousand in 2021 and $5 thousand in 2022.

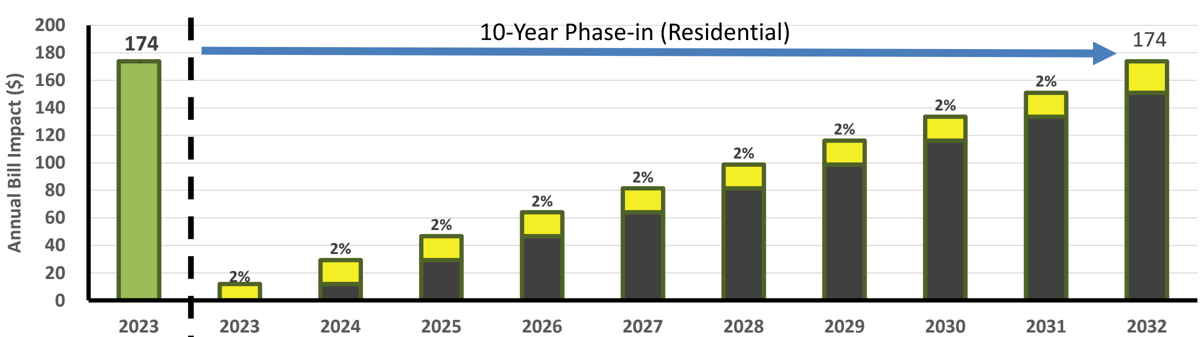
This is equivalent to $0.007 per GJ for FEI's customers, or $0.59 to FEI's residential customers with an average consumption of 90 GJs.

Table 5-17: Forecast Residential 10-year Phase-in Rider and FEI Deficiency

Line	Particular	Reference	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	Incremental Delivery Margin for FEFN RS 1 ($000s)	Section 5.5	319									
2	Effective Incremental Delivery Rate ($/GJ)	Line 1 / Line 9 (2023)	1.391									
3	Annual Incremental of Phase-In ($/GJ)	Line 2 / 10 Years	0.139									
4												
5	Residential Phase-in Common Rates Rider ($/GJ)	Yr 1 = -(Line 2 - Line 3); Yr 2 to 10 = Prev Yr + Line 3	(1.252)	(1.113)	(0.974)	(0.834)	(0.695)	(0.556)	(0.417)	(0.278)	(0.139)	-
6	2021 FEFN Surplus Revenue Rider ($/GJ)	-$94 thousand / (10 yrs - 1) / Line 9	(0.045)	(0.045)	(0.045)	(0.045)	(0.045)	(0.045)	(0.045)	(0.045)	(0.045)	-
7	Total FEFN Residential Phase-in Rider ($/GJ)	Line 5 + Line 6	(1.297)	(1.158)	(1.019)	(0.880)	(0.741)	(0.602)	(0.463)	(0.324)	(0.185)	-
8												
9	FEFN Residential Demand Forecast (TJ)	Section 4.3.2.1	230	230	230	230	230	230	230	230	230	230
10	Total FEFN Phase-in Rider Costs ($000s)	- Line 7 x Line 9	298	266	234	202	170	138	106	74	42	-
11												
12	FEFN Phase-in Rider Deferral ($000s)											
13	Opening Balance	Preceeding Year, Line 19	94	323	208	181	157	132	107	83	58	33
14	Additions	Line 10	298	266	234	202	170	138	106	74	42	-
15	Less Tax	- Line 14 x 27%	(80)	(72)	(63)	(55)	(46)	(37)	(29)	(20)	(11)	-
16	AFUDC	(Line 13 + (Line 14 + 15 + 18)/2) x 5.47%	11	14	10	9	8	6	5	4	2	-
17	Net Additions	Sum of Line 14 to 16	229	208	181	157	132	107	83	58	33	-
18	Amortization to FEI's Delivery Rates	- Line 13	-	(323)	(208)	(181)	(157)	(132)	(107)	(83)	(58)	(33)
19	Closing Balance	Line 13 + Line 17 + Line 18	323	208	181	157	132	107	83	58	33	-
20												
21	2021 FEI Approved Delivery Margin ($000s)	G-319-20	879,479									
22	Cumulative Amortization to FEI ($000s)	- Sum of Line 18	1,282									
23	% Cumulative Delivery Rate Impact to 2021	Line 22 / Line 21	0.15%									

Figure 5-3 below shows the annual bill impact to the average FEFN residential customer over the 10-year period after incorporating FEI's proposed phase-in approach, which is a gradual increase to the residential customer bill each year until reaching the total bill impact of $174 related to the delivery portion of the common rates in the tenth year (See Section 5.3.5.2). The annual bill increase for an average FEFN residential customer is approximately $17 per year (i.e., the yellow portion of the bar graph each year).

Figure 5-3: Illustration of 10-year Phase-in Rider for an Average FEFN Residential Customers



5.6 *PROPOSED COMMON RATE OPTION IS SUPPORTED BY CONSIDERATION OF BONBRIGHT'S RATE DESIGN PRINCIPLES*

In this section, FEI assesses the Proposed Common Rate Option against the rate design principles identified by Dr. Bonbright. These principles, as articulated by the BCUC in a previous BC Hydro Decision[35], in no particular order, are:

- Principle 1: Recovering the Cost of Service; the aggregate of all customer rates and revenues must be sufficient to recover the utility's total cost of service.
- 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.
- 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.
- Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

FEI does not apply the eight principles above in any priority or with any particular weighting; however, FEI notes that different rate design principles may have varying levels of importance in different contexts. FEI therefore applies its experience and judgment to consider and balance the most relevant principles in a given context.

The principles FEI considers most relevant to this Application are:

- Principle 2: Fair apportionment of costs among customers;
- Principle 4: Customer understanding and acceptance;
- Principle 5: Practical and cost-effective to implement;
- Principle 6: Rate stability; and
- Principle 8: Avoidance of undue discrimination.

Table 5-18 below discusses how the Proposed Common Rate Option addresses each of the relevant rate design principles.

[35] Appendix A to Order G-45-11 in the matter of the BC Hydro Residential Inclining Block Rate Re-Pricing Application.

Table 5-18: Summary of Rate Design Principles for the Proposed Common Rate Option (Option 4)

Relevant Rate Design Principle	Description	Option 4 – Common Delivery and Cost of Gas with Midstream set at 5% of FEI's Midstream Rates
Principle 2 – Fair apportionment of costs among customers	Appropriate cost recovery should be reflected in rates and should be based on cost causation	Fair apportionment implies the recovery of costs based on cost causation. Under common rates, all customers within the same rate class receive the same level of service regardless of their location within the service area, which includes FEFN. Therefore, it would be fair apportionment for all customers receiving the same service, which includes FEFN, to pay the same rates. FEFN is the only remaining service area within FEI that is not included in FEI's common rates, despite the fact that FEFN represents only 0.24 percent of FEI in terms of customer count or 0.21 percent in terms of demand. As discussed in Section 4.3.1.1, FEFN currently has only two direct employees serving Fort Nelson while the majority of FEFN's operations are performed by FEI resources. As a result, the majority of FEFN's annual O&M expenses are comprised of a shared services fee allocated from FEI. The shared services fee is a calculation based on an allocation of customer counts rather than the true cost. If FEFN were required to operate as a standalone utility, significantly more direct employees for FEFN would be needed and it is reasonable to assume that the resulting O&M costs would be higher. Similarly, as discussed in Section 4.3.1.2, FEFN's natural gas cost portfolio is managed by FEI which is optimized for FEFN due to the fact that FEI is a large regional buyer of natural gas. In short, FEFN is already integrated with FEI and has been benefiting from this integration by receiving the full support of FEI's resources at a relatively low cost and through an optimized gas supply portfolio due to negotiations with suppliers being undertaken by a utility as large as FEI. Thus, it would be fair and appropriate for FEFN to move to common rates with the rest of FEI.

Relevant Rate Design Principle	Description	Option 4 – Common Delivery and Cost of Gas with Midstream set at 5% of FEI's Midstream Rates
Principle 4 – Customer understanding and acceptance	"The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application. Freedom from controversies as to proper interpretation"[36]	The Proposed Common Rate Option involves no changes to the existing rate structure for FEFN customers, which was approved as part of the FEI RDA Decision and Orders G-4-18 and G-135-18. This approved rate structure was implemented as of January 1, 2019. The fact that there is no change to the rate structure on customers' natural gas bills will assist with customers' understanding of the proposed common rates. Having a single common rate for both delivery and cost of gas across all service areas will improve the ease of understanding for all FEI customers through more consistent rate treatment. With regard to ease of acceptance, FEI acknowledges that due to the manner in which FEFN physically receives gas and its proximity to the Fort Nelson plant, FEFN's midstream rates have historically been lower than FEI, and that this has been a key point of FEFN customers' opposition to moving to common rates (see Section 6 for details of FEI's consultation and engagement). As such, while FEI proposes to amalgamate FEFN's gas cost portfolio into FEI's MCRA, FEI does not propose to move FEFN customers to common midstream rates. Instead, FEI proposes to set FEFN's midstream rates at 5 percent of FEI's midstream rates, which is a reasonable historical approximation of FEFN's midstream rate. This results in a negligible rate impact to FEFN customers from moving to common commodity rates. Additionally, the proposed phase-in rate rider for FEFN's residential customers ensures that the changes will be gradual and small over a 10-year period, which aligns with the principle of ease of acceptance.
Principle 5 – Practical and cost-effective to implement	Sustainable and easy to administer by the Company as well as meeting long-term objectives	The Proposed Common Rate Option is practical and efficient for FEI and results in reduced regulatory burden. It is also easy to administer and there will be no incremental costs required to implement. For comparison, the average regulatory proceeding costs for FEFN's RRA are $45.5 thousand under the status quo option.

[36] Bonbright, James C., Danielsen, Albert L., and Kamerschen, David R., Principles of Public Utility Rates, 2nd ed.

Relevant Rate Design Principle	Description	Option 4 – Common Delivery and Cost of Gas with Midstream set at 5% of FEI's Midstream Rates
Principle 6 – Rate Stability	Customer rate impact should be predictable and managed, with minimum unexpected rate increases that are seriously adverse to existing customers	For FEFN customers, the Proposed Common Rate Option will provide increased delivery rate stability over time. As described in Section 4.3.4, FEFN customers have experienced high delivery rate volatility historically, which is primarily due to the decline in FEFN's overall demand since 2015 and the various sustainment capital projects that entered rate base over the years. Common delivery rates will help address this rate volatility issue given FEI's much broader customer base to absorb pressures on the revenue requirement due to increased costs or decreased demand. The proposed phase-in rate rider also ensures there is no sudden and adverse impact to FEFN residential customers due to the transition to common rates.
Principle 8 – Avoidance of undue discrimination	Interclass equity must be enhanced and maintained	FEI considers that the Proposed Common Rate Option is not unduly discriminatory or unduly preferential to any customer classes but will significantly enhance rate stability for customers in Fort Nelson without material impact or changes to FEI's customers. The Proposed Common Rate Option will result in savings for FEFN's commercial customers but will cause a rate increase for FEFN's residential customers. However, the proposed phase-in rate rider for FEFN's residential customers helps to limit this short term impact for the overall benefit of increased future rate stability. As discussed in Section 5.5, the proposed phase-in rate rider for FEFN's residential customers has a minimal impact to FEI's customers. With regard to the proposal to set FEFN's midstream rates at 5 percent of FEI, this approach helps to maintain FEFN's midstream rates at similar levels to what FEFN customers are paying now while having no material impact to FEI's existing non-bypass customers. As demonstrated in Section 5.3.5, setting FEFN's midstream rates at 5 percent of FEI has a cumulative impact of only 15 cents to FEI's average residential customers over a 10-year period if the proposed rate-setting mechanism was implemented in 2011.

5.7 *BENEFITS OF THE PROPOSED COMMON RATE OPTION*

Table 5-19 below describes the pros and cons of the Proposed Common Rate Option.

Table 5-19: Pros and Cons of the Proposed Common Rate Option

Attribute	Pros	Cons
Rate Stability	Provides long-term delivery rate stability for FEFN customers as the impacts of localized reductions in demand and increases in costs will no longer be absorbed by only FEFN's small customer base.	FEFN customers may experience greater midstream rate volatility as the balance in FEI's MCRA will fluctuate; however, the impact of such fluctuations on FEFN will be mitigated due to FEFN only being allocated 5 percent of the MCRA balance.
Bill Impact	For 2023, FEFN's small and large commercial customers will experience a savings of $159 and $841, respectively, in their bills due to the adoption of common rates. Incrementally when compare to status quo (i.e., bill impact due to common rates only), the small and large commercial customers will see savings of $350 and $3,327, respectively.	The total estimated impact for FEFN's residential customers will be an incremental bill increase of $157 due to adoption of common rates. However, with the proposed 10-year phase-in rate rider for FEFN's residential customers, the average bill impact is reduced to approximately $17 per year over a 10-year period.
Fair apportionment of Costs	As discussed in Section 5.3.5.1, the proposed common delivery and cost of gas rates reflect the shared cost of providing energy service to FEI and FEFN.	While the proposal to set FEFN's midstream rates at 5 percent of FEI's midstream rates better reflects FEFN's current physical supply arrangement and its proximity to the gas plant, this treatment results in FEI customers bearing some of FEFN's gas supply costs (however, as noted in Section 5.3.5.1, the impact to FEI customers is negligible).
Regulatory Burden and Costs	Significantly reduces the regulatory process and costs of separate filings for FEFN, including revenue requirement applications, annual reports, quarterly gas costs reports, and any CPCN applications.	None.

5.8 Conclusion

FEI recommends transitioning FEFN customers to common delivery and cost of gas rates, and to amalgamate FEFN and FEI's gas cost portfolios such that FEFN will be charged 5 percent of FEI's midstream rates.

This Proposed Common Rate Option will align FEFN with the rest of FEI's service areas and achieves the four key Objectives described previously in Section 5, which are:

- Eliminate regulatory filings and costs;
- Provide long-term rate stability for FEFN customers;
- Achieve fairness across all FEI service areas, including FEFN; and
- Mitigate rate impacts to FEFN customers resulting from the adoption of common rates.

The issue of common rates has been raised many times over the years in various revenue requirement and rate design applications, and it has historically not been supported due to the rate impact to Fort Nelson customers of moving to common rates, despite the fact that from a rate design principles and a government policy standpoint, common rates are well supported.

As discussed above, FEFN currently has only two direct employees, and an average of 54 percent of FEFN's O&M expenses and 24 percent of FEFN's revenue requirement are made up of allocated costs from FEI. As such, the current rates for FEFN are not representative of the true regional differences in the costs to serve between FEFN and FEI. Furthermore, the gap between FEFN and FEI rates has been closing in recent years due to the declining trend in FEFN customer demand and increased cost pressures resulting from the need for capital sustainment activities. At this time, as has been the case for the past few years, commercial customers in Fort Nelson are now paying higher delivery rates than FEI commercial customers.

It is, therefore, beneficial to FEFN commercial customers to move to common rates, as shown in the above analysis, as the Proposed Common Rate Option will result in savings to commercial customers. FEI acknowledges that under any of the common rates options, there will be a negative rate impact to FEFN residential customers; however, under the Proposed Common Rate Option this impact is reduced, and the proposed 10-year phase-in rate rider provides an appropriate time frame over which to achieve common residential delivery rates.

FEI notes FEFN is already integrated with the larger FEI utility, and a move to common rates reflects the operational and financial reality of the current situation. Furthermore, in recognition of FEFN's proximity to the Fort Nelson gas plant and the manner in which gas is currently physically contracted and delivered to FEFN customers, FEI is proposing to calculate the FEFN midstream rates in a manner that results in FEFN customers paying approximately the same midstream rates going forward as they are currently paying, which is an amount that is significantly lower than FEI's other customers.

In the following sections of the Application, FEI describes the consultation it has undertaken and plans to undertake (Section 6), how the Proposed Common Rate Option will be implemented (Section 7), and the forecast 2022 revenue requirement and proposed delivery rate increase for FEFN (Section 8).

6. CONSULTATION AND ENGAGEMENT

6.1 *INTRODUCTION*

Consultation and engagement with Indigenous groups, FEI customers, the public and stakeholders are integral components of FEI's project and application development process. As part of the engagement planning process for this Application, FEI has and continues to work to ensure that Indigenous groups and stakeholders are informed about the Application[37], and that their feedback and concerns are received and appropriately addressed where possible.

In this section, FEI will:

- Provide an overview of the Indigenous and stakeholder engagement approach (Section 6.2);
- Demonstrate how FEI is undertaking, and will continue to undertake, appropriate stakeholder engagement regarding the Application (Section 6.3); and
- Demonstrate how FEI is undertaking, and will continue to undertake, appropriate engagement with Indigenous groups regarding the Application (Section 6.4).

6.2 *FEI'S ENGAGEMENT APPROACH AND OBJECTIVE*

FEI's approach to engagement on the Application is to strive to ensure Indigenous groups and stakeholders are informed about the purpose and content of the Application and have an opportunity and are encouraged to provide feedback and raise concerns that may be considered as part of the decision-making process.

Consistent with other applications, FEI identified a number of objectives that drive engagement for the Application, including:

- Informing stakeholders using plain language to clearly communicate the potential impacts, opportunities and potential solutions associated with the Application;
- Providing timely and relevant updates about the Application to enable Indigenous groups, customers, the public, government, and other stakeholders to provide input during the regulatory process;
- Gathering feedback from Indigenous groups, customers, the public, government, and other stakeholders on the impact of the Application and on their interests related to the Application; and
- Where possible, addressing concerns and incorporating feedback related to the Application.

[37] FEI notes that its engagement activities to date have focused on the common rate components of the Application, not the 2022 revenue requirement and delivery rate change component.

Consistent with these objectives, FEI's engagement has focused on creating dialogue centered around educating groups on the pricing mechanism of gas rates, the components of customers' natural gas bills, and the impact of changes in costs and consumption on Fort Nelson customers, while also providing an opportunity for FEI to listen to concerns and issues raised. FEI has addressed these concerns and issues wherever possible. FEI's engagement will continue to focus on information sharing, encouraging feedback, and responding to questions and concerns raised.

6.3 *FEI IS UNDERTAKING APPROPRIATE STAKEHOLDER ENGAGEMENT*

FEI describes below how it is undertaking, and will continue to undertake, appropriate stakeholder engagement to support the Application development and approval process.

6.3.1 Stakeholders Impacted by the Application

As part of its engagement planning process, FEI has identified several groups potentially impacted by and/or who may have an interest in the Application. Information has and will continue to be shared with each of the following groups as appropriate (Indigenous groups are discussed in Section 6.4):

- Fort Nelson customers;
- Municipal and regional government including: the Mayor, Council, City Manager and/or staff from the municipality of Fort Nelson; and
- Industry and industrial associations such as the Fort Nelson & District Chamber of Commerce and local community groups that may have an interest in the Application.

6.3.2 Public Consultation and Communication Materials and Methods

Information about the Application was shared with Fort Nelson customers and other stakeholders throughout the Application development process using a number of communication materials and methods which are described in more detail below. These materials and methods were designed to inform and gather feedback from stakeholders regarding the Application, and specifically serve to:

- Provide information and rationale about the move to common rates for Fort Nelson customers;
- Solicit feedback to understand concerns and issues;
- Answer any questions in relation to the Application; and
- Maintain transparency throughout the process with the public.

Webpage

A new webpage fortisbc.com/fortnelsonrates went live on February 26, 2021, and provided:

- Details of the Application and the BCUC process;
- Benefits of common rates to Fort Nelson customers;
- Information on how to participate in the virtual town hall session;
- A link to provide feedback through an online survey (see Appendix C3 for the survey and survey results); and
- A dedicated email - fortnelson.customers@fortisbc.com.

Virtual Town Hall

Public open houses provide an opportunity to engage with stakeholders face-to-face, answer questions and address concerns. Due to the COVID-19 pandemic and restrictions on safe gatherings, FEI held a virtual town hall on April 27, 2021 that was advertised over print media, radio and social media.

While 75 people registered for the event, 17 attended the session, including individuals from School District 81 and members of the Fort Nelson & District Chamber of Commerce (FNDCC).

At the event, a presentation (Appendix C1) was given by FEI subject matter experts, providing information about the Application and the process. Attendees were encouraged and provided with an opportunity to ask questions. Following the virtual town hall, the Power Point presentation was made available on FEI's dedicated Application webpage, and included a link to the online survey to gather additional feedback.

Additionally, at the request of the FNDCC, FEI representatives met virtually on May 4, 2021 with the FNDCC after the virtual town hall to further discuss the Application proposals and gather feedback on the materials presented at the town hall.

Paid and Social Media

FEI ran an advertising campaign using radio, newspaper, and social media during the months of March and April to reach customers and the broader community of Fort Nelson. The following advertising channels were used during the campaign:

- A 30 second radio spot ran on CKRX-FM 102.3 (Appendix C2), the sole radio station in the area, which advertised the virtual town hall and invited feedback from Fort Nelson customers. 204 spots were broadcast during traffic reports, weather and breakfast news during the campaign period;
- Four half-page, black and white newspaper ads and two half-page, full colour ads were released in two newspapers – *Fort Nelson News* and *Alaska Highway News*. Copies of

the newspaper carrying the advertisement were also dropped at Prophet River First Nation by special request (Appendix C2);

- Facebook, geo targeted to adults 35+ in the location of Fort Nelson and spread over a 30 km radius, was used to promote the virtual town hall session, resulting in 75 registrations for the event; and
- FEI's Twitter platform was also used to promote the virtual town hall session to broaden the reach and increase participation. This was re-shared by the FNDCC, Fort Nelson Municipality and Fort Nelson First Nation among their account followers to help maximize participation.

Media Outreach

FEI also engaged with media outlets in the weeks leading up to the virtual town hall. Reporters and members of the Fort Nelson media were informed through direct media outreach about the Application, the process followed by FEI, the public engagement and online surveys. This resulted in stories being published in the *Alaska Highway News* on April 22, 2021 and *Energeticcity.ca* on March 30 and April 22, 2021, as well as an events listing on *allevents.in* (Appendix C2).

Regional Council Presentation

FEI presented to the Fort Nelson Regional Council on June 14, 2021. This presentation was broadcast on YouTube (June 14, 2021 Special Regional Council Meeting - YouTube). Three FEI subject matter experts presented at the council meeting and answered questions on the common rate proposals. Questions received during the presentation are detailed in Section 6.3.3 below. The Power Point presentation provided at this meeting is attached as Appendix C5.

6.3.3 Summary of Stakeholder Feedback Received

6.3.3.1 Summary of Feedback from Virtual Town hall

FEI received a variety of questions during the virtual town hall regarding the Application. A total of 33 questions were asked by attendees using the virtual chat function, and were answered by FEI representatives present during the meeting. Some questions that required additional information such as technical inputs, were not answered at the town hall session. Along with other questions, these questions and answers were included in a Frequently Asked Questions (FAQ) document (Appendix C4) developed based on the questions received. The FAQ document was added to the webpage fortisbc.com/fortnelsonrates on June 10, 2021.

The questions raised by members of the public at the virtual town hall are detailed in Table 6-1 below, organized by theme. The table also indicates whether a question was asked more than once by the number at the end of the question. All questions that were asked at the virtual town hall were answered at the event or through a FAQ section on FEI's website.

Table 6-1: Summary of Audience Questions at Virtual Town Hall

Topic	Question
Rates	Will storage and transport rates, and delivery rates, be the same for Fort Nelson customers? (3)
	Why would Fort Nelson customers pay the same rates as everyone else, when the natural gas comes from Fort Nelson? (2)
	Will Fort Nelson customers be paying more overall? (3)
	Why is the delivery charge for business higher here than FEI - we are a lateral from the plant here. It should not be higher.
	So to go to common rates we are looking at ~30% increase for residential? (2)
	With our bills reaching upward of $400 a month in cold months how much will this raise our bill?
	We burn more gas than the rest of the province and the billing is based on gas used so there will be no decrease.
	While rate changes may be smoother - currently if we look at 2021 rates Fort Nelson is about 25% less than the mainland based on the same usage - what is planned that would bring that gap closer (3)
Infrastructure	Is FortisBC planning more system improvements in the area? (2)
Bills	If the application is approved, do customers need to do anything or will the change be reflected on their bills? Will bills look any different? (2)
	Is there a program to help with high bills such as a payment plan? (2)
	I feel that my bill has been much larger than the forecasted $280/year increase - just for this past year - I am very concerned about the current costs this winter already. Can you elaborate more on why our Fortis costs were so high already this winter and can you confirm, that these costs are going to increase regardless of the option that is selected? It seems that no matter what, we are going to continue paying more and more for our gas? Perhaps a spreadsheet showing your different options with their associated costs one just one slide alone would help us compare.
	After receiving my bill this winter and having $283 storage and transport I was shocked. I was told to call the BCUC to complain about our rates, but I don't see from your presentation how common rates are going to help residential customers here, just that it's going to get more expensive.
General	We are hearing about the possible advantages - what are the possible disadvantages? Will there be further public information sessions?
	What are the benefits to Fort Nelson customers for having the same rates as all other FortisBC natural gas customers? (2)
	Does this add any benefits for any rebates or green house building upgrade? (2)
	With this proposed rate change, will FortisBC make more money? (2)
	Where does Fortis store the natural gas that Fort Nelson customers consume? How much does that cost Fortis?
	How does this work if the customer uses a different gas suppler?

6.3.3.2 Summary of Online Survey Report

Leading up to the virtual town hall in April, FEI conducted an online survey (Appendix C3) on the dedicated FortisBC Application webpage. The survey was live from March 15, 2021 until June

10, 2021. The online survey attracted 18 responses. While the results of the survey are informative, they does not represent a statistically valid survey as only 18 people responded, therefore making it difficult for FEI to draw any concrete conclusions from the survey.

More than half of the respondents (66 percent) were not supportive of moving to common rates. If approved by the BCUC, about half of the respondents would like common rates phased in over five years (46 percent) while a third (31 percent) would like rates to be phased in over 15 years. Only a fifth of the respondents (21 percent) were interested in a phase-in option tailored to residential, small commercial and large commercial customers. 36 percent were not interested in this option.

A majority (83 percent) of respondents indicated that they were interested to learn about the proposed rate changes, while 33 percent also wanted to learn about billing and rates. Survey participants indicated a preference for receiving project-related communication via emails and virtual town hall sessions.

Additional questions raised by members of the public through the online survey are detailed in Table 6-2 below, organized by theme.

Table 6-2: Additional Information Requested by Survey Participants

Topic	Question/Comment
Rates	I attended the virtual presentation. Fortis described the rate increase that Fort Nelson customers have had due to the Muskwa River project. What are the near term maintenance and upgrade projects planned for Fort Nelson and what are the implications to natural gas costs for Fort Nelson customers due to the planned work (exclusive of any other commodity or shipping increases, or reduction in Customer numbers or usage)?
	I would like to see reduced rates for residential customers!
	Is there an example of other communities or districts in BC where Fortis Gas has put common rates in place, where and when was this done, which communities did it impact, did those communities see decreases rate?
	What will the change cost the average residential customer?
	We need transparent, understandable (to the lay person) rate comparisons and transparent, understandable future considerations.
	If it is approved, what is the forecast proposed increase for Fort Nelson Residential Customers, in dollar terms and percentage?
	Why Fortis thinks this change is acceptable, you already gouge us on the transportation of the gas that only travels 25km now you need to explain why you think we should pay the same transportation rates as Vancouver 1600 km of pipeline south.
	With a natural gas plant in Fort Nelson, should our rates not be lower than far distant communities?

6.3.3.3 Summary of Feedback from Regional Council

Questions raised by the Regional Council are detailed by theme in Table 6-3 below. FEI subject matter experts present responded to these questions at the event.

Table 6-3: Summary of Questions Asked at Fort Nelson Regional Council Presentation

Topic	Question
Rates	Question from Mayor - Would a large commercial customer located in Fort Nelson reduce the delivery costs?
	Question from Mayor - Can it be taken as a long term promise that over the next 25 years there will not be an increase in the transportation and cost of gas component rate?
	Both the effects of all vs delivery only were shown, and it was said that all components is unlikely, so how unlikely?
	What did the rates look like if Fort Nelson does not go with common rates?
	Is there any other motive beside the BCUC asking FEI to propose common rates?
	What is the percentage gap currently between the Fort Nelson and the FEI rates?
Infrastructure	Question from Mayor - The delivery rates are a function of the capital costs, is there any plans for future capital investments in Fort Nelson and what would the costs be?
	Question from Mayor - Throughout the rest of the province there are capital upgrades, what do the costs look like throughout the province? So what is the difference between Fort Nelson local improvements and the burden of the rest of the province?
Application	Will further details be released about what the actual plan will be until the application is supplied to the BCUC?

6.3.4 Public Consultation and Engagement Plans Going Forward

During the upcoming regulatory process, FEI is committed to continued engagement with Fort Nelson customers, the public and other identified stakeholders.

To overcome logistical challenges and facilitate greater engagement, FEI will continue to have email-based conversations and will offer additional opportunities for providing greater understanding of the Application and its implications through virtual meetings. If approached, FEI will offer to host specific sessions for smaller groups such as the Municipality of Fort Nelson leadership and staff and at different times of the day to enable greater participation from the public.

FEI will also continue to work with organizations such as the FNDCC to promote the virtual sessions among their members, and on request, provide virtual sessions to communities such as local business owners and low income societies. FEI will continue to engage with all identified stakeholders to address outstanding concerns throughout the lifecycle of the Application.

6.3.5 FEI's Public Consultation Process to Date has been Appropriate

FEI believes that the communication and consultation activities to the time of filing the Application have been sufficient, appropriate and reasonable given the nature of this Application. FEI is dedicated to maintaining and strengthening positive relationships through an open and transparent consultation process with government, natural gas customers and the public, and will continue to engage with stakeholders and the public regarding throughout the process, and leading up to decision.

6.4 *FEI's ENGAGEMENT WITH INDIGENOUS COMMUNITIES*

FEI is committed to building strong working relationships with Indigenous groups guided by FEI's Statement of Indigenous Principles (see Appendix C6) which states the importance of clear and open communication with Indigenous groups. FEI believes that its engagement process for the Application reflects these principles. Through early engagement activities, FEI has established key points of contact, preferred methods of communication, and an early understanding of potential interests from Indigenous groups. As the Application progresses, FEI will continue to work through these channels to resolve outstanding questions and address comments and concerns.

In this section, FEI outlines the Company's approach to the identification of and early engagement with potentially impacted Indigenous groups, and details the Company's Indigenous engagement plans going forward.

6.4.1 Potentially Impacted Indigenous Groups Identified

There are two Indigenous groups in the Fort Nelson service area – the Fort Nelson First Nation (FNFN) and the Prophet River First Nation (PRFN). FEI serves and provides gas to both communities. FNFN has residential customers on Reserve lands who are directly billed by FEI, while Prophet River First Nation is currently an FEI commercial customer, with one meter located off-Reserve that provides service to the community on Reserve land[38].

6.4.2 Description of Consultation with Indigenous Groups to Date

FEI has been engaging with both Indigenous groups from early on in the Application development process. The Chief and Council were first informed of the Application by email, and were sent follow up emails during the months of February and March 2021.

The advertisements previously described in Section 6.3.2 inviting the public to the virtual town hall were also widely distributed in the Fort Nelson First Nation community through the sharing and reposting of social media posts on their social media channels.

[38] As part of the FEFN 2019-2020 RRA, FEI was granted a CPCN for the purchase of the PRFN distribution assets, which would result in FEFN acquiring PRFN's distribution system assets and the PRFN customers being converted from one commercial customer to individual residential customers. However, FEI is currently waiting for federal approval of the Section 28(2) permit, and until such time as the permit is approved, the PRFN continue to receive service as one commercial customer.

FEI also offered to give both the Fort Nelson First Nation and the Prophet River First Nation a separate presentation on the Application, the regulatory process and its potential impacts on each Indigenous community. The FNFN invited FEI to provide a virtual presentation to the Chief and Council on May 18, 2021 (please see Section 6.4.3 below for further details). FEI has not received a response from the PRFN as at the time of filing the Application.

6.4.3 Summary of FEI's Indigenous Engagement

FEI had a virtual meeting with the Chief and Council of the Fort Nelson First Nation on May 18, 2021, where FEI made a presentation about the Application and responded to a variety of questions.

A summary of the questions raised during the presentation to Chief and Council are summarized by theme in Table 6-4 below. These questions were answered by FEI subject matter experts present at the meeting.

Table 6-4: Summary of Questions from Fort Nelson First Nation Chief and Council

Topic	Question
Rates	What are common rates as opposed to special rates?
	Can costs be reduced if gas were coming from a local LNG facility that has been / is being built in the First Nation?
	What is the average increase in rates?
	What would the average cost of gas to each unit/dwelling in the FNFN area be?
Infrastructure	Where is the gas currently coming from?
	Are there any capital projects planned?
General	Is this proposal of common rates just to increase FortisBC profits?
	With the pandemic and all that is trying for those of us living in the North, now may not necessarily be the best time to join the Fort Nelson service area with FEI; however, as the commercial rates could potentially decrease significantly, this is also kind of a “catch-22” for whether the change in rates will benefit Fort Nelson customers.

6.4.4 FEI Will Continue to Engage with Indigenous Groups

Through the regulatory process, FEI will continue to engage with Indigenous groups by maintaining contact with the Indigenous groups impacted by the Application, and will provide them with a notification of the filing, the regulatory review process and timetable established by the BCUC, and when a decision has been reached. While the COVID-19 pandemic has posed challenges for in-person engagement with Indigenous groups, FEI has made efforts to engage through other means, and will continue to keep both Indigenous groups informed and offer meetings as appropriate throughout the Application process.

6.5 *FEI HAS TAKEN FEEDBACK INTO CONSIDERATION IN THE APPLICATION*

As discussed above, FEI has sought and received a variety of feedback through the virtual town hall, online survey, direct emails from customers, and meetings with the Fort Nelson Regional Council, the Fort Nelson & District Chamber of Commerce, and the Fort Nelson First Nation Chief and Council.

Based on the feedback and dialogue undertaken, FEI developed the Proposed Common Rate Option, which takes into consideration Indigenous groups' and stakeholders' concerns about residential customer rate increases and increased midstream charges given Fort Nelson's proximity to the Fort Nelson gas plant. In the virtual town hall presentation, attached as Appendix C1 to this Application, FEI presented two options for common rates – moving to common delivery rates and cost of gas and moving to full common rates (i.e., common delivery, cost of gas, and midstream rates). Based on the feedback received, it became clear that moving to full common rates, similar to what FEI had proposed in past common rates applications, is not supported by Fort Nelson customers. FEI therefore developed and has proposed an alternative common rate proposal that maintains FEFN's midstream rates at a level consistent with existing rates and provides rate mitigation measures specifically targeted to residential customers. Please refer to Section 5 for a detailed explanation of the Proposed Common Rate Option and Section 7 for a detailed explanation of how the Proposed Common Rate Option will be implemented.

In summary, FEI has recorded and addressed questions, issues, and concerns from Indigenous groups and stakeholders. FEI will continue to engage with Indigenous groups and stakeholders as the regulatory proceeding advances.

7. IMPLEMENTATION AND ACCOUNTING MATTERS

As discussed in Section 5, given the timing of the filing of this Application and the anticipated regulatory process, a BCUC decision on the Application is not expected to be reached prior to the end of 2021. In consideration of this, FEI proposes to implement the Proposed Common Rate Option for FEFN on January 1, 2023 to enable a more coherent transition, as it coincides with FEI's rate change dates for delivery, cost of gas, and midstream charges, and also allows FEI to incorporate the forecast 2023 revenue requirement impacts of FEFN in FEI's Annual Review for 2023 Delivery Rates (2023 Annual Review), which will be filed mid-2022. In this section, FEI describes the implementation of the Proposed Common Rate Option for FEFN, effective January 1, 2023, which is to move FEFN to common delivery and cost of gas rates and to set FEFN's midstream rates at five percent of FEI's midstream rates through amalgamation of FEI and FEFN's gas cost portfolios. FEI also proposes to utilize a phase-in rate rider for FEFN's residential customers to mitigate the rate impact due to the transition to common rates.

As outlined in Section 2 and described in detail in Section 8, as part of this Application FEI is also applying for approval of 2022 delivery rates for FEFN based on the forecast revenue requirement for FEFN as a standalone service area. If the Proposed Common Rate Option is approved, 2022 will be the last year that a separate revenue requirement and delivery rates will be developed for FEFN.

7.1 *IMPLEMENTATION OF COMMON RATES*

Implementation of common rates for FEFN will result in a number of changes, including to FEI's gas costs portfolio, rate base, O&M expenses, deferral accounts, and its rate schedules and tariff.

7.1.1 Changes to FEI's Gas Cost Portfolio

If the Application is approved, FEFN will move to a common cost of gas rate with FEI, and FEFN's midstream rates will be set based on 5 percent of FEI's midstream rates. In order to implement these changes, FEFN's gas cost portfolio, which includes commodity and midstream amounts, will be amalgamated into FEI's existing MCRA, as discussed in Section 5.3.5.1 Further, FEFN's GCRA balance will be transferred to FEI's MCRA as an opening balance adjustment on January 1, 2023, and FEFN's GCRA will then be eliminated.

FEI notes that the proposed changes only impact the regulatory accounting treatment of FEFN's natural gas costs. There is no change to how the physical natural gas supply for FEFN is planned and managed. Commencing in 2023, FEI will report on FEFN's natural gas supply costs as part of FEI's quarterly gas cost reports and will no longer file separate quarterly FEFN gas cost reports. The BCUC will still be able to review FEFN's gas supply portfolio costs, as these costs will continue to be tracked separately and presented in the FEI gas cost reports.

7.1.2 Changes to FEI's Rate Base

With common delivery rates between FEFN and FEI, FEFN will no longer have a separate rate base. Assuming common delivery rates are effective on January 1, 2023, FEI will transfer the closing December 31, 2022 balances of FEFN's gross plant in service, accumulated depreciation, Contributions in Aid of Construction (CIAC), and the accumulated amortization of CIAC, to FEI's rate base as January 1, 2023 opening balance adjustments. The FEFN ending balances will be recorded in the equivalent FEI asset and CIAC accounts.

FEI will also transfer FEFN's capital work in progress (no AFUDC), working capital, and unamortized deferred charges to FEI's rate base under the same categories. FEI's working capital calculation will implicitly be updated to include the impact of the underlying FEFN components of working capital that would now exist in the consolidated entity. For changes specifically related to deferral accounts, please refer to Section 7.1.4 below.

As described in Section 8, FEI is seeking approval to adopt updated common accounting policies for FEFN which were approved for FEI as part of the 2020-2024 Multi-year Rate Plan (MRP) Decision and Order G-165-20. If adoption of these common accounting policies are approved, FEFN's capitalized overhead rate, depreciation and net salvage rates, and the lead/lag days used to calculate cash working capital will be consistent with FEI. Therefore, no changes would be required upon moving to common delivery rates in 2023.

The amalgamation of the FEI and FEFN rate bases would result in only a minor increase to FEI's rate base. For instance, FEFN's approved 2021 rate base is approximately $12.503 million, which represents approximately 0.2 percent of FEI's approved 2021 rate base of $5.212 billion.

7.1.3 Changes to FEI's Formula O&M and Growth Capital, and Forecast Regular Capital

As explained in Section 4, FEI has been filing annual or bi-annual revenue requirements for FEFN. Since FEFN has maintained separate delivery rates and separate revenue requirements from FEI, FEFN is not currently operating under FEI's 2020-2024 MRP. Adjustments to FEI's formula O&M and forecast regular capital expenditures will therefore be required to incorporate FEFN. If common delivery rates are approved, these adjustments will be included as part of FEI's 2023 Annual Review so that common delivery rates can take effect January 1, 2023.

7.1.3.1 Formula O&M Expense

Under the MRP, FEI's annual O&M expense is primarily determined by formula. FEI was approved for a Base O&M per Customer (UCOM) amount as part of the MRP Decision, and this UCOM is escalated annually by an inflation factor less a productivity improvement factor, or a net inflation factor. In order to account for FEFN's O&M as part of FEI's formula O&M, FEI will add FEFN's forecast 2023 customer count to FEI's forecast 2023 customer count, thus incorporating FEFN into the 2023 formula O&M calculation. To illustrate the impact of this on FEI's formula O&M, had FEFN's customer count been added to the calculation of FEI's 2021 formula O&M, FEI's O&M would have increased by $932 thousand, which is comparable to FEFN's approved 2021 gross O&M expense of $935 thousand. This increase to FEI's formula O&M equates to an increase of 0.34 percent (FEI's approved 2021 formula O&M is $272.5 million).

7.1.3.2 Growth Capital Expenditures

Under the MRP, FEI's growth capital is determined annually by formula. This formula calculation is the prior year's approved unit cost for growth capital (UCGC) escalated by a net inflation factor, which includes a forecast of FEI's gross customer additions. Gross customer additions are new customers attaching to the gas distribution system and comprise both new construction activity and conversions from other fuels to natural gas.

As FEFN's existing customers do not represent new customer additions to FEI, they would not be added to the gross customer additions forecast for 2023 and therefore no adjustment is required to the growth capital formula. Any new customer additions forecast for FEFN for 2023 and beyond will be included as part of FEI's forecast 2023 new customer additions (just as FEVI and FEW have been included in the FEI forecast since the move to common rates approved in 2015).

7.1.3.3 Sustainment and Other Capital Expenditures

As discussed in Section 4, sustainment and other capital expenditures are required annually to maintain the natural gas system in FEFN. Assuming that common delivery rates are effective January 1, 2023, FEI will incorporate FEFN's forecast sustainment and other capital expenditures for 2023 and 2024 as part of FEI's updated forecasts for 2023 and 2024 sustainment and other capital, which FEI will be providing as part of its 2023 Annual Review. FEI notes that the proposed effective date of January 1, 2023 to move FEFN to common rates aligns well with FEI's annual review applications, as FEI was directed as part of the MRP Decision[39] to file updated regular capital forecasts for 2023 and 2024 as part of the 2023 Annual Review. FEI will therefore include forecasts for FEFN's sustainment and other capital as part of the updated forecasts to be filed in the 2023 Annual Review.

7.1.4 Changes to FEI's Deferral Accounts

FEFN currently has 12 rate base deferral accounts[40] and three non-rate base deferral accounts. FEI will consolidate the FEI and FEFN deferral accounts as part of the implementation of common rates. The following subsections describe the consolidation of deferral accounts as well as FEI's proposed treatment of FEFN's existing 2021 Revenue Surplus deferral account.

[39] MRP Decision, p. 131.

[40] The 2019-2020 Revenue Requirement Application deferral account will be fully amortized at the end of 2021, as such, Table 7-1 describes the treatment for 11 rate base and 3 non-rate base deferral accounts.

7.1.4.1 Consolidation & Transfer of FEFN's Existing Deferral Accounts to FEI

Table 7-1 below summarizes the changes to FEFN's existing deferral accounts:

Table 7-1: Consolidation/Transfer of FEFN's Existing Deferral Accounts to FEI

	FEFN's Existing Deferral Accounts	Notes
Consolidation with FEI's existing deferral accounts	**Rate Base Deferrals:** • Revenue Stabilization Adjustment Mechanism (RSAM) • Interest on RSAM • Gas Cost Reconciliation Account (GCRA) • Demand-Side Management (DSM) • 2017 Rate Design Application • Gains and Losses on Asset Disposition • Net Salvage Provision/Cost • COVID-19 Customer Recovery Fund **Non-Rate Base Deferral:** • Demand-Side Management (DSM)	• These deferral accounts will be consolidated with FEI's existing deferral accounts with the same name, except for the GCRA. • FEFN's GCRA will be consolidated with FEI's existing MCRA deferral account as discussed in Section 5.3.5.1. • Assuming common rates are implemented for January 1, 2023, consolidation will result in the closing balance of FEFN's deferral accounts on December 31, 2022 being transferred to FEI's existing deferral account with the same name as an opening balance adjustment on January 1, 2023.

FEFN's Existing Deferral Accounts		Notes
Consolidate into a single deferral account and transfer to FEI	**Rate Base Deferrals:** • Property Tax Variance • Interest Variance • Billing System Costs for FEFN Rate Changes (per FEI's 2016 Rate Design Application)	• These deferral accounts are specific to FEFN. FEI does not have similar accounts for the same purpose or with the same name. • The forecast balance of these three accounts at December 31, 2022 is $9 thousand. Given the relatively small balance, FEI proposes to consolidate these three deferral accounts into one, named "FEFN Transitional Balance" deferral account, and transfer to FEI with an amortization period of one year. Please refer to Section 7.1.4.2 for more details.
Transfer to FEI as separate deferral accounts	**Non-Rate Base Deferral:** • FN Right-of-Way Agreement • FEFN 2021 Revenue Surplus	• These deferral accounts are specific to FEFN. FEI does not have similar accounts for the same purpose or with the same name. • These FEFN deferral accounts will be transferred to FEI as new deferral accounts (renamed with "FEFN" added to the existing name). • For the FN Right-of-Way Agreement deferral account, FEI will request disposition in a future proceeding (please refer to Section 8.6.4.2 for more details on the status of the agreement). • As discussed in Section 5.5, FEI proposes to use the remaining credit balance at the end of 2022 of the non-rate base FEFN 2021 Revenue Surplus deferral account towards the FEFN Residential Common Rate Phase-in Rate Rider. Please refer to Section 7.1.4.4 below for further details.

7.1.4.2 New FEFN Transitional Balance Deferral Account

If the Proposed Common Rate Option is approved, FEI proposes to consolidate three of FEFN's existing deferral accounts – Property Tax Variance deferral account, Interest Variance deferral account, and the Billing System Costs for FEFN Rate Changes deferral account – into a single rate base deferral account, titled "FEFN Transitional Balance" deferral account, and transfer this consolidated deferral account to FEI on January 1, 2023. The total forecast balance of these three deferral accounts on December 31, 2022 is $9 thousand (see Section 8 and Appendix E1, Schedule 8, Lines 5, 6 and 15 for the forecast ending 2022 balances of these three FEFN deferral accounts). Once transferred, FEI proposes to amortize this remaining balance into FEI's delivery rates over one year in 2023.

7.1.4.3 New FEFN Common Rates and 2022 Revenue Requirement Application Costs Deferral Account

FEI requests approval of a new rate base deferral account – the FEFN Common Rates and 2022 Revenue Requirement Application Costs deferral account. This deferral account will capture the regulatory costs associated with this Application and regulatory review process. In Section 8.6.4.1, FEI provides a detailed description of this new deferral account and addresses the considerations identified in the BCUC's Regulatory Account Filing Checklist.[41]

If the Proposed Common Rate Option is approved, the FEFN Common Rates Application Costs deferral account will be transferred to FEI as of January 1, 2023. FEI would propose an amortization period for this deferral account as part of the 2023 Annual Review. If the Proposed Common Rate Option is not approved, the deferral account would remain with FEFN, and FEI would apply for disposition of the deferral account in the next FEFN revenue requirement, which would be filed in 2022.

7.1.4.4 Treatment of the Existing FEFN 2021 Revenue Surplus Deferral Account

As part of the Proposed Common Rate Option, FEI proposes to phase in the move to common delivery rates for residential Fort Nelson customers over 10 years, through the establishment of the FEFN Residential Common Rate Phase-in Rate Rider. In order to implement the rate rider, FEI also requires establishment of a deferral account; however, instead of creating a new deferral account, FEI proposes to add the revenue deficiency created by phasing in residential delivery rates over 10 years to the existing FEFN 2021 Revenue Surplus deferral account. This deferral account, which was approved as part of the 2021 Deferral Account Decision[42], has a forecast ending 2022 after-tax balance of $94 thousand (credit). This balance is comprised of the approved 2021 revenue surplus of $132 thousand, less FEI's external legal costs and BCUC direct costs related to the review of the 2021 Deferral Account Application which total $14 thousand, less income taxes of $32 thousand, plus carrying charges accrued on the deferral account balance of $3 thousand in 2021 and $5 thousand in 2022.

By combining the revenue deficiency created by phasing in residential delivery rates with the revenue surplus in the already approved FEFN 2021 Revenue Surplus deferral account, the annual credit amount of the FEFN Residential Common Rate Phase-in Rate Rider will be higher, and will thus serve to further reduce the annual bill impact that will be experienced by FEFN's residential customers resulting from the transition to common rates.

This treatment is appropriate since only FEFN's residential customers will experience a bill increase as a result of the transition to common rates, while FEFN's commercial customers will experience savings on their bills. Furthermore, this treatment will ensure FEFN's customers, and not FEI's customers, will benefit from this surplus accumulated within FEFN.

FEI therefore requests approval to rename the existing FEFN 2021 Revenue Surplus deferral account to the FEFN Residential Common Rate Phase-in deferral account, and to amortize the deferral account balance over the same 10-year period as the proposed FEFN residential phase-in rate rider. Please refer to Table 5-17 in Section 5.5 for an illustration of the FEFN residential phase-in rate rider over a 10-year period, which includes the 10-year continuity of

[41] Log No. 53608, Appendix B.
[42] Order G-78-21.

this deferral account. FEI notes the FEFN residential phase-in rate rider shown in Table 5-17 is for illustrative purposes only and is calculated based on FEFN's 2022 residential demand forecast shown in Section 4.3.2.1. FEI proposes to set the actual phase-in rate rider each year in FEI's annual review based on an updated forecast of FEFN's residential customer demand and the remaining balance of the deferral account each year for the 10-year period.

7.1.5 Proposed Amendments to the FEI Tariffs

As discussed in further detail in the subsections below, the Proposed Common Rate Option will require certain amendments to the FEI Tariff Rate Schedules 1 (Residential), 2 (Small Commercial) and 3 (Large Commercial), effective January 1, 2023.

Please refer to Appendix D, which contains blacklined versions of the FEI Tariffs, with the required revisions to reflect the Proposed Common Rate Option.

7.1.5.1 Cancellation of the FEFN Gas Tariff and Proposed Customer Mapping

The FEFN Gas Tariff (FEFN Tariff) sets out the BCUC approved rate schedules, rates, and terms and conditions (if applicable), for each of FEFN's different service offerings.

Please refer to the table below which provides a summary of the proposed FEFN rate schedule mapping, and cancellations resulting from the proposed cancellation of the FEFN Tariff effective January 1, 2023:

Table 7-2: Summary of FEFN Tariff Rate Schedule Mapping and Cancellations

FEFN Gas Tariff Rate Schedule	Proposed Mapping or Cancellation
RS 1: (Residential Service)	Move existing FEFN RS 1 (Residential Service) customers to FEI RS 1 (Residential Service).
RS 2: (Small Commercial Service)	Move existing FEFN RS 2 (Small Commercial Service) customers to FEI RS 2 (Small Commercial Service).
RS 3: (Large Commercial Service)	Move existing FEFN RS 3 (Large Commercial Service) customers to FEI RS 3 (Large Commercial Service).
RS 5: (General Firm Service)	Cancel rates and service offering effective January 1, 2023 (there are currently zero customers enrolled).
RS 6: (Natural Gas Vehicle Service)	Cancel rates and service offering effective January 1, 2023 (there are currently zero customers enrolled).
RS 25: (General Firm Transportation Service)	Cancel rates and service offering effective January 1, 2023 (there are currently zero customers enrolled).

As described in the above table, FEI proposes to move existing FEFN customers to the equivalent applicable FEI rate schedule, and cancel FEFN RS 5, 6 and 25. Currently, there are no customers enrolled in RS 5, 6 and 25, and historically only one customer has been enrolled in RS 5 since January 1, 2019.[43] Therefore, FEI believes there is no demand for these service offerings for FEFN customers at this time. If the Proposed Common Rate Option is approved, and should FEFN customers request service under other FEI rate schedules not proposed in this Application to be made available to FEFN customers, FEI would file a separate application in the future for any additional tariff changes as may be required.

In summary, if the Proposed Common Rate Option is approved, FEI proposes to cancel FEFN RS 5, 6 and 25 and move existing FEFN RS 1, 2 and 3 customers to the equivalent FEI RS 1, 2 and 3, effective January 1, 2023.

7.1.5.2 Proposed Amendments to FEI Rate Schedules

As outlined in Table 7-2 above, FEI is proposing to move existing FEFN RS 1, 2 and 3 customers to FEI RS 1, 2 and 3 by adding the Fort Nelson service area to these rate schedules as well as including the revised common delivery rate and cost of gas treatment as proposed in the Application.

Please refer to the table below which provides a summary of the proposed FEI RS 1, 2 and 3 amendments effective January 1, 2023.

Table 7-3: Summary of Proposed Amendments to FEI RS 1, 2 and 3

FEI Rate Schedule	Service Area	Delivery Margin Related Rate Riders Applicable to Fort Nelson Customers

RS 1 (Residential Service)	Add New Fort Nelson Service Area column	• Existing:
		  ○ Rider 2 – Clean Growth Innovation Fund Account
		  ○ Rider 5 – Revenue Stabilization Adjustment Charge (RSAM)
		• New Proposed Rider Applicable ONLY to Fort Nelson customers:
		  ○ Rider 4 – FEFN Residential Common Rate Phase-in

RS 2 (Small Commercial Service)		• Existing:
		  ○ Rider 2 – Clean Growth Innovation Fund Account
		  ○ Rider 5 – Revenue Stabilization Adjustment Charge (RSAM)

RS 3 (Large Commercial Service)		• Existing:
		  ○ Rider 2 – Clean Growth Innovation Fund Account
		  ○ Rider 5 – Revenue Stabilization Adjustment Charge (RSAM)

As discussed in Section 7.1.4.1 above, if the Application is approved, FEI proposes to consolidate FEFN's RSAM deferral account with FEI's RSAM deferral account. The relatively

[43] FEI 2016 RDA Decision and Order G-135-18.

small balance of FEFN's RSAM will have no change to the calculation of FEI's RSAM rate rider (after rounding to three decimal places).

7.1.5.3 Service Offerings

The FEI General Terms and Conditions (GT&Cs) set out the BCUC approved terms and conditions of service provided by FEI to all service territories, including FEFN. FEI is not proposing any amendments to the FEI GT&Cs at this time.

FEI is also not proposing in this Application to make other service offerings such as Customer Choice or FEI's Renewable Natural Gas (RNG or Biomethane) Program[44] available to FEFN customers at this time. If the Proposed Common Rate Option is approved, FEI will consult with FEFN customers to determine whether there is interest in other service offerings and, if so, file future applicable application(s).

In summary, FEI seeks approval of the cancellation of the FEFN Tariff and amendments to the FEI rate schedules, effective January 1, 2023.

7.2 CONCLUSION

The Proposed Common Rate Option, if approved, will require a number of changes to FEI's financial schedules and tariff; however, the effort and cost of this implementation is relatively minor. The required implementation measures includes the following:

- Amalgamation of FEFN and FEI's gas cost portfolios;
- Consolidation of FEFN's rate base and deferral accounts with FEI;
- Changes to FEI's capital and O&M under the current MRP to include FEFN's capital and O&M expenses;
- Approval of the FEFN Residential Common Rate Phase-in Rate Rider, and to set the actual phase-in rate rider each year in FEI's Annual Reviews;
- Changes to the existing FEFN 2021 Revenue Surplus deferral account to facilitate the implementation of the proposed FEFN Residential Common Rate Phase-in Rate Rider; and
- Minor amendments to the FEI Tariff and specific rate schedules.

[44] Any potential future application to make FEI's RNG Program available to FEFN customers would not occur before a decision in FEI's upcoming comprehensive RNG Program review expected to commence sometime in 2021.

8. 2022 DELIVERY RATES

8.1 *INTRODUCTION*

As part of the Application, FEI requests approval of an effective delivery rate increase of 3.41 percent effective January 1, 2022, as well as approval to set the RSAM rate rider at a credit of $0.416 per GJ effective January 1, 2022. Given that FEI expects that permanent delivery rates will not be able to be approved prior to the beginning of 2022, FEFN is seeking approval of these rates on an interim and refundable basis. If the Proposed Common Rate Option is approved, this will be the final year that delivery rates will be set separately for FEFN, as customers will be transitioned to common rates effective January 1, 2023.

Based on the forecast energy demand for FEFN, the forecast revenue at the approved 2021 delivery rates is not sufficient to recover FEFN's required revenue requirement over the 2022 test period. Specifically, FEI forecasts a revenue deficiency of $83 thousand.

The largest driver of the revenue deficiency is the decrease in energy demand. As discussed in Section 8.3, FEFN is forecasting a declining customer count and use per customer for both the residential and commercial customer classes. As a result, total energy demand is forecast to decline in 2022 and the decrease in demand compared to 2021 Approved[45] energy demand contributes $99 thousand to the forecast revenue deficiency in 2022.

Other contributing factors to the net revenue deficiency are:

- Rate base growth due to capital additions required for system maintenance, which contributes $65 thousand to the revenue deficiency. Details of FEFN's required capital additions are provided in Section 8.6.2;
- An increase of $70 thousand in depreciation and amortization expense for the test period, which is primarily due to the increase in amortization of deferral accounts and net salvage provision (see Section 8.6.4 for details on FEFN's deferral accounts); and
- An increase of $23 thousand in taxes, mostly attributable to an increase in income taxes resulting from increases in earned return and taxable income (see Section 8.5 for details on taxes).

Partially offsetting the above-described contributors to the 2022 revenue deficiency are the following:

- A reduction in net O&M of $3 thousand;
- A reduction in financing costs of $34 thousand;
- An increase in Other Revenue of $5 thousand; and

[45] "2021 Approved" is the 2021 forecast revenue requirements and the individual components of the 2021 forecast revenue requirements provided in the FEFN 2021 Deferral Account Application, approved by Order G-78-21.

- The elimination of the 2021 deferred revenue surplus of $132 thousand from the 2022 revenue requirement.

The approvals sought in this section appropriately recover the costs of serving FEFN customers and the required capital improvements to continue service to FEFN customers.

FEI notes a certain percentage of FEFN's revenue requirement is impacted by the accounting policies approved for FEI. Consistent with the treatment approved in previous revenue requirements for FEFN, FEI is seeking approval to adopt updated common accounting policies that were recently approved for FEI. Specifically, FEI seeks approval of the following for FEFN which were approved for FEI as part of the MRP Decision and Order G-165-20:

- Capitalized overhead rate of 16 percent (previously 12 percent);
- Depreciation and net salvage rates as determined in FEI's most recent depreciation study approved through Order G-165-20; and
- Modification to the lead/lag days, as set out in FEI's most recent lead/lag study approved through Order G-165-20, for calculation of FEFN's cash working capital.

The impacts due to these updated accounting policies are reflected in the net revenue deficiency summarized above.

8.2 *2022 REVENUE REQUIREMENT, RATES AND RSAM RATE RIDER*

The forecast 2022 revenue requirement for FEFN is $3,949 thousand (Appendix E1, Schedule 12, Line 9, Column 5). FEI is forecasting a total revenue deficiency of $83 thousand for FEFN in 2022 (Appendix E-1, Schedule 1, Line 32, Column 3). This results in an effective delivery rate increase of 3.41 percent in 2022 when compared to the approved 2021 delivery rates. For a typical FEFN residential customer consuming an average of 125 GJs per year, this equates to an increase in the annual bill of approximately $22 (or 2.3 percent)[46].

Table 8-1 below summarizes the annual bill impact in dollars and in percentage for the average customer by each rate schedule due to the 2022 forecast revenue deficiency. For the FEFN 2022 tariff continuity and a detailed calculation of the annual bill impacts, please refer to Appendix E2.

[46] Does not include the impact of the RSAM rate rider, which increases from a credit of $0.333 per GJ in 2021 to a credit of $0.416 per GJ in 2022. If the changes to the RSAM rate rider are included, the increase to the annual bill is approximately $12 (or 1.2 percent) in 2022 for the average residential customer consuming approximately 125 GJs per year.

Table 8-1: Annual Bill Impact for Average Customer due to 2022 Revenue Deficiency

			2022	
Rate Schedule		GJ	Annual $ Increase	% of Previous Annual Bill
Rate Schedule 1	Residential Service	125	$ 22	2.3%
Rate Schedule 2	Small Commercial Service	335	$ 65	2.3%
Rate Schedule 3	Large Commercial Service	6,375	$ 835	1.9%

FEI notes that FEFN does not have any customers served under Rate Schedules 5, 6 or 25.

Order G-17-04 granted approval for the implementation of the RSAM account for FEFN to capture variations in the delivery margin (Revenue less Cost of Gas) for residential, commercial and industrial rate classes[47]. Order G-17-14 subsequently approved a change in the amortization period for the RSAM account from three years to two years. The RSAM account accumulates the annual RSAM debits and credits with one half of the net balance being recovered or refunded in the following year via a rate rider.

The RSAM rate rider has been calculated in a manner consistent with past practice. For 2022, the RSAM rate rider is a credit of $0.416 per GJ to be refunded back to FEFN's customers effective January 1, 2022, as shown in Table 8-2 below.

Table 8-2: 2022 RSAM Rate Rider

RSAM + RSAM Interest, Projected December 31, 2021 Balance	(285.0)
Amortization Period (years)	2
2022 Amortization post-tax ($000)	(142.5)
Tax Rate	27%
2022 Amortization pre-tax ($000)	(196.0)

RSAM (Rider 5) Calculation			
Rate Class	RSAM Amortization ($000)	2022 Volume (TJ)	Rider ($/GJ)
Rate Schedule 1		233.8	(0.416)
Rate Schedule 2		150.2	(0.416)
Rate Schedule 3		87.2	(0.416)
	(196)	471.2	(0.416)

47 As part of the FEI 2016 RDA Decision, the RSAM was approved to be phased-out for FEFN's Rate Schedule 5 and Rate Schedule 25 (Industrial Class) class. As of November 2020, FEFN no longer has any industrial class customers.

8.3 GAS SALES AND DEMAND, AND OTHER REVENUE

8.3.1 Introduction

This section responds to previous BCUC directions to provide information on FEI's demand forecast for FEFN, describes the forecast demand for FEFN residential and commercial customers for 2022, calculates FEFN's forecast revenue based on the forecast total energy demand, and sets out the forecast of Other Revenue.

FEI's natural gas demand forecast for FEFN is based upon methods that are consistent with those used in prior years, and provide a reasonable estimate of natural gas demand for 2022 and for the future years discussed in Section 4.3.2. In compliance with the directive issued by the BCUC in Order G-162-16[48], FEI includes detailed information on its forecast method in Appendix A3 (Demand Forecast Method) of this Application.

For 2022, FEI is forecasting a total normalized demand of 471.2 TJs, which is a decrease of 21.1 TJs compared to the forecast filed in the FEFN 2021 Deferral Account Application. Based on the 2021 approved rates for each customer class, FEFN's 2022 revenue and gross delivery margin forecast are $3.866 million and $2.434 million, respectively.

8.3.2 Overview of Forecast Methods

The forecast demand for FEFN is comprised of two main components: (1) Customer additions (account) forecast; and (2) Average use per customer (UPC) forecast.

The residential and commercial energy forecast, consisting of customers served under Rate Schedules (RS) 1, 2, and 3, is driven by the respective account and use per customer forecasts. The average use per customer is estimated for customers served under RS 1, 2, and 3 and is then multiplied by the corresponding forecast of customers in each rate class to derive energy consumption.

Current approved 2021 rates are applied against the energy forecast to calculate the forecast revenue. The cost of gas is subtracted from this forecast revenue to calculate the delivery margin (also referred to as gross margin), which is used as part of the calculation of the 2022 revenue deficiency.

In the figures provided in the following subsections, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. The 2022 revenue requirement is based on actual data up to and including 2020;
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the

[48] Directive 7 of Order G-162-16 directed FEI to "file the supporting calculations for the residential and small commercial use per customer and customer additions forecasts in its future requirement applications for the Fort Nelson service area."

original forecast for that year in the previous filing. For this Application, the Seed Year is 2021 and the Seed Year forecast is based on the latest actual years, including 2020. As such, the 2021 Seed Year forecast in this Application will differ from the 2021 Forecast presented in the 2021 Deferral Account Application, which was based on 2020 preliminary actual data; and

- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (as is presented in this section of the Application), or a range of two or more years (as presented in Section 4.3.2).

8.3.3 Customer Additions

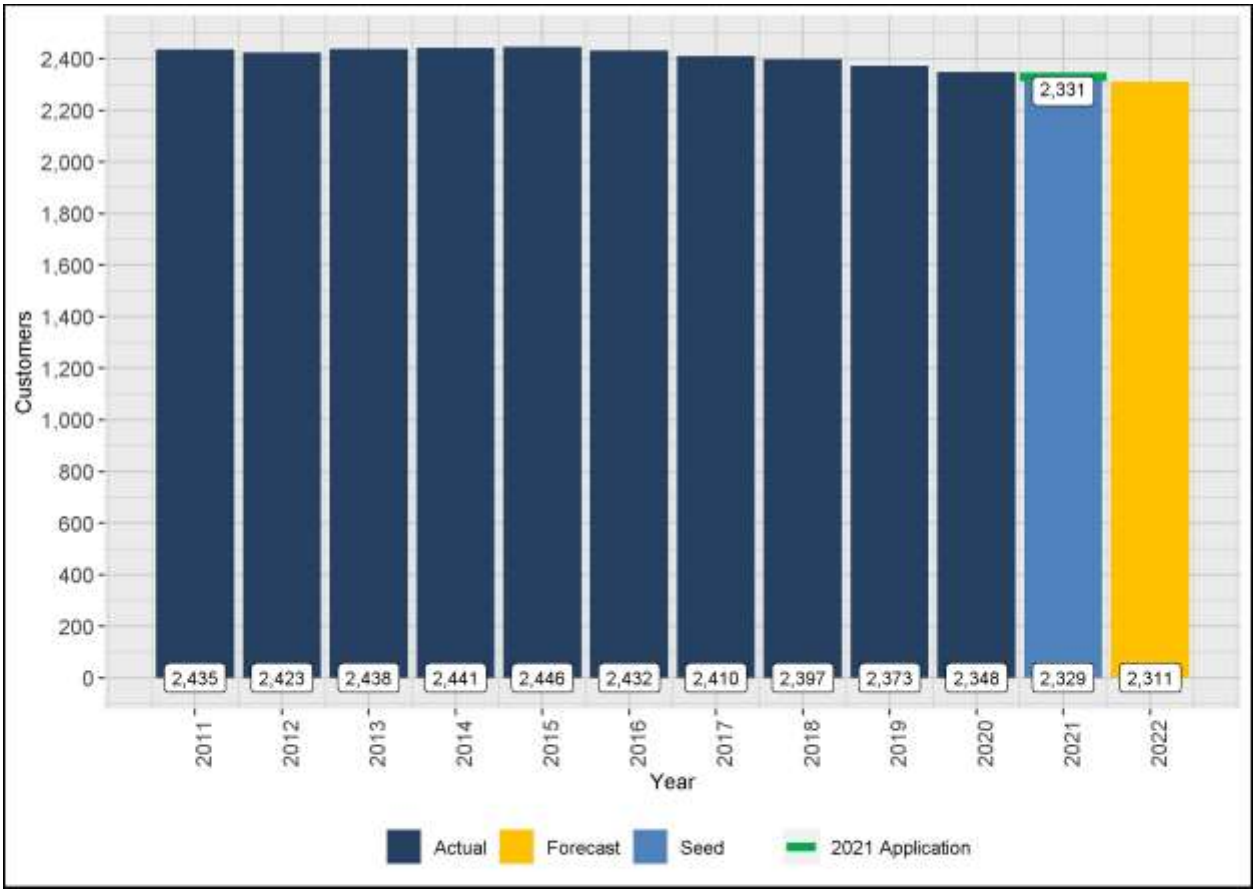
The forecast of customer accounts is the first component of determining the total energy demand. The Conference Board of Canada (CBOC) housing starts forecast provides a proxy for Fort Nelson's residential customer additions. The year-over-year growth rate is calculated for 2022 based on the CBOC Provincial Outlook Long-Term Economic Forecast, April 29, 2021 (see Appendix A1).

The commercial additions forecast is based on the three-year average of the actual additions recorded between 2017 and 2020.

See Appendix A3 for a more detailed description of FEFN's customer additions forecast method.

Figure 8-1 below shows the total number of customers at year-end (i.e., December 31) in the residential and commercial segments.

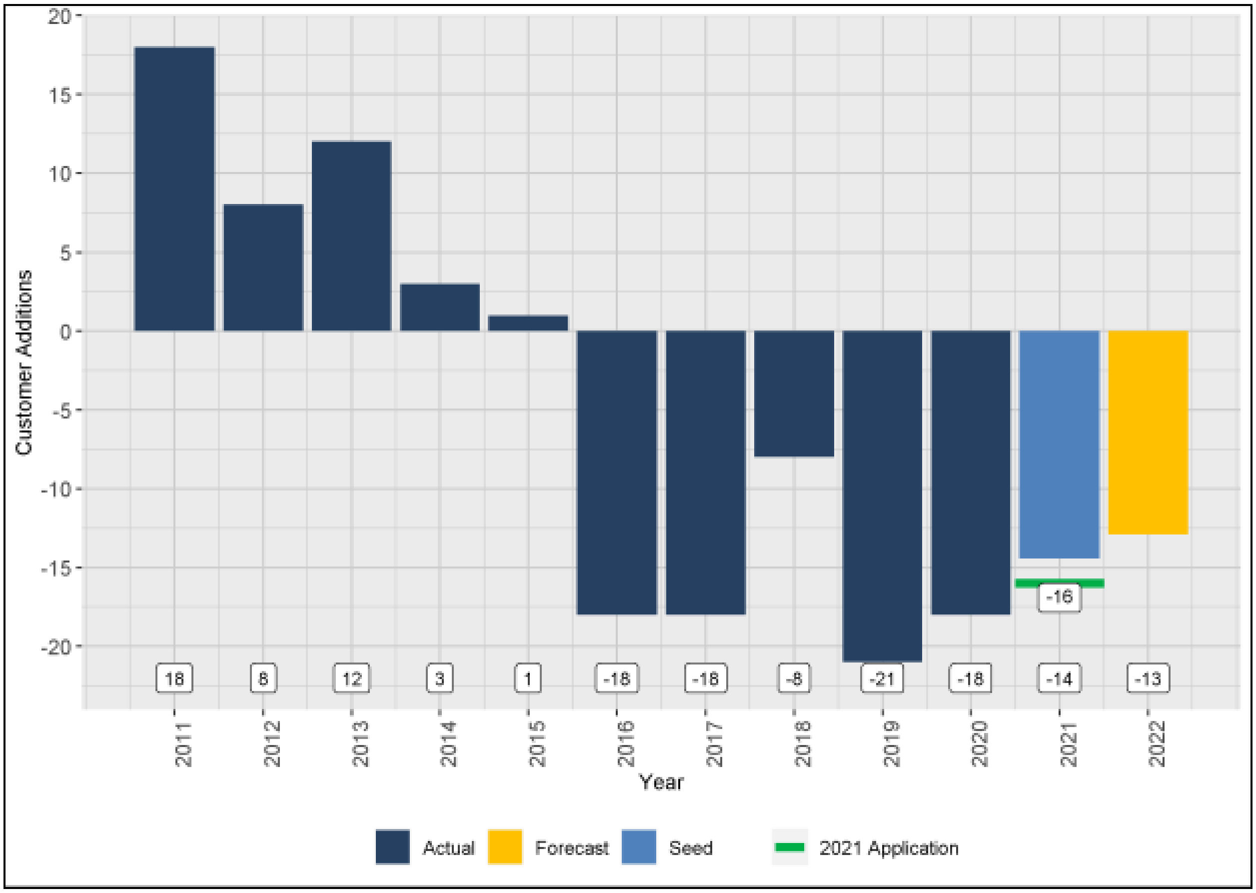
Figure 8-1: Total Customers at Year End



8.3.3.1 Residential Customer Additions

As shown in Figure 8-2 below, net residential customer (RS 1) additions have been negative since 2016. Customer losses in 2020 were slightly less than in 2019. FEI is forecasting a decline of 13 customers in 2022.

Figure 8-2: Residential Customer Additions

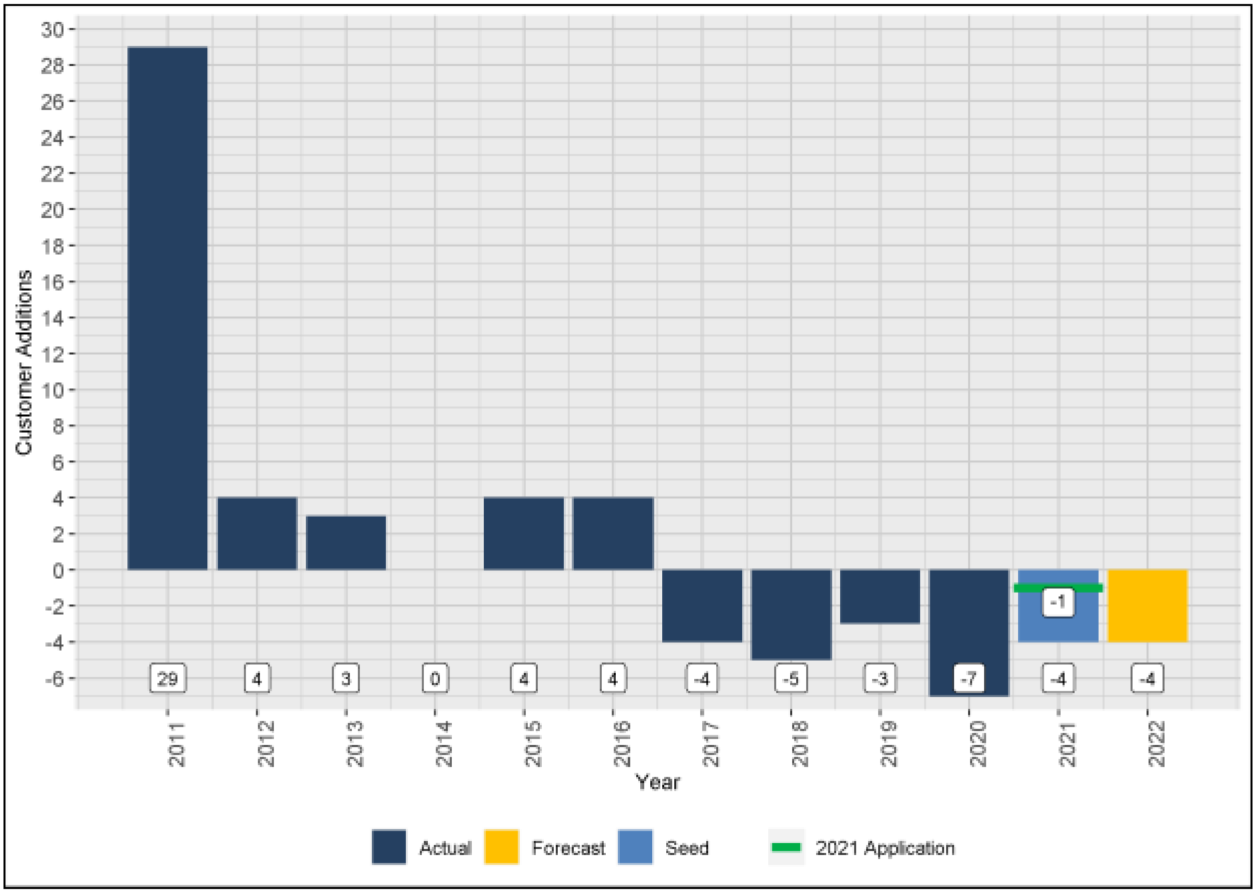


8.3.3.2 Commercial Customer Additions

As shown in Figure 8-3 below, commercial customer (RS 2 and 3) additions have also been negative since 2017. FEI develops the commercial customer forecast with a three-year average of customer additions and therefore is forecasting a decline of four[49] customers in 2022.

49 FEI notes that Figure 8-3 is the aggregate of RS 2 and RS 3. RS 2 customer additions are forecast to be declining by 3 while RS 3 customer additions are forecast to be declining by 1.

Figure 8-3: Commercial Customer Additions

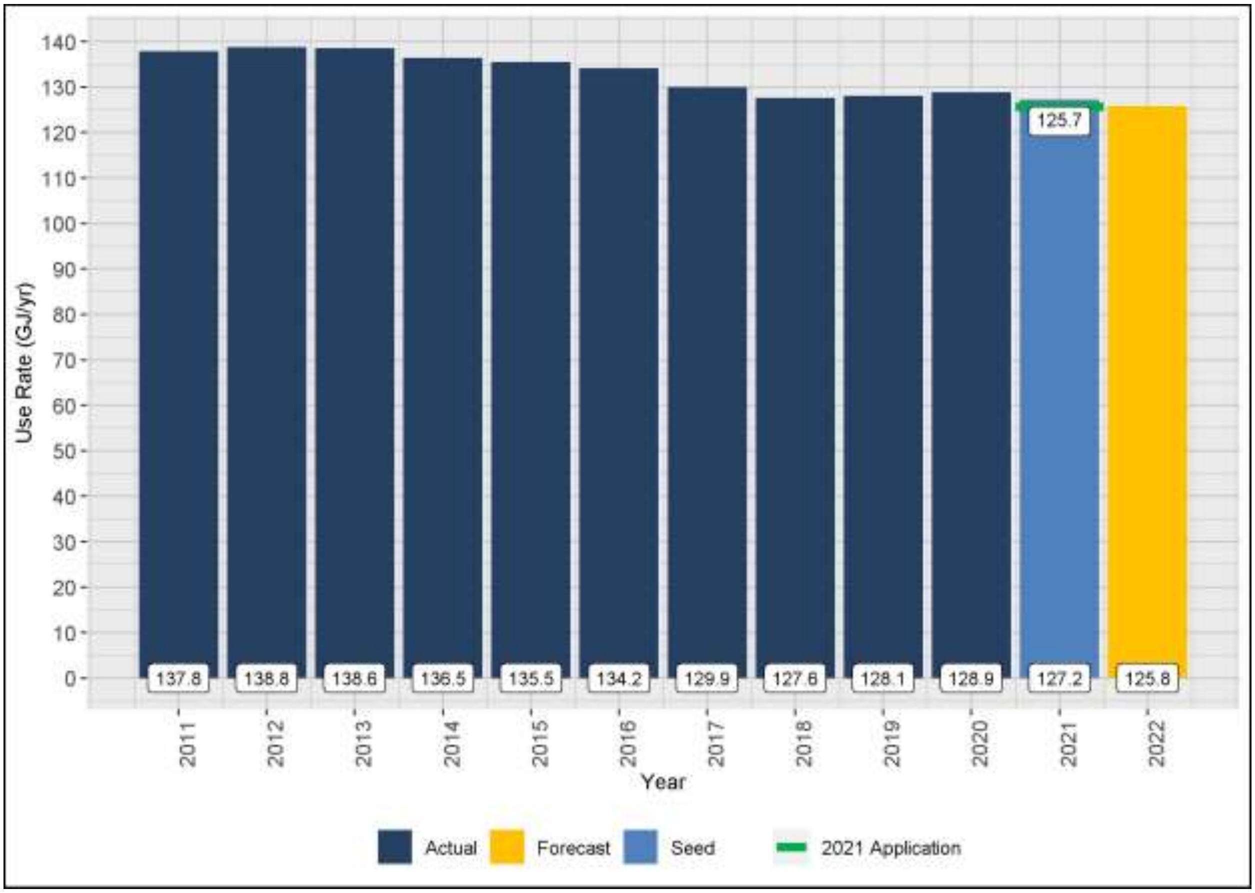


8.3.4 Use Rates

FEI developed individual use per customer (UPC) forecasts for each rate schedule by considering the most recent 10 years of historical weather-normalized UPC data. See Appendix A3 for a detailed description of FEI's UPC forecast method.

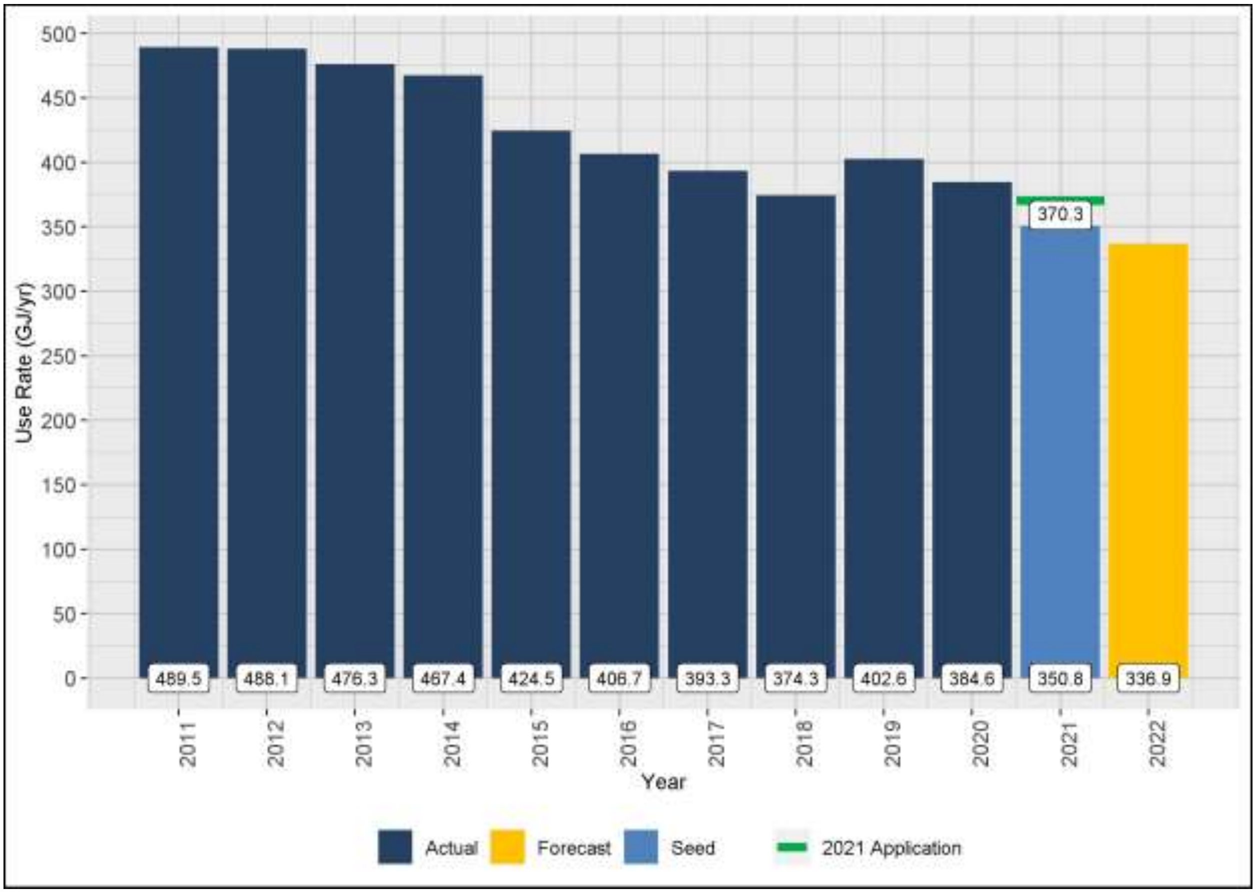
The RS 1 UPC is forecast to continue to decline through 2022 as seen in Figure 8-4 below.

Figure 8-4: Rate Schedule 1 UPC



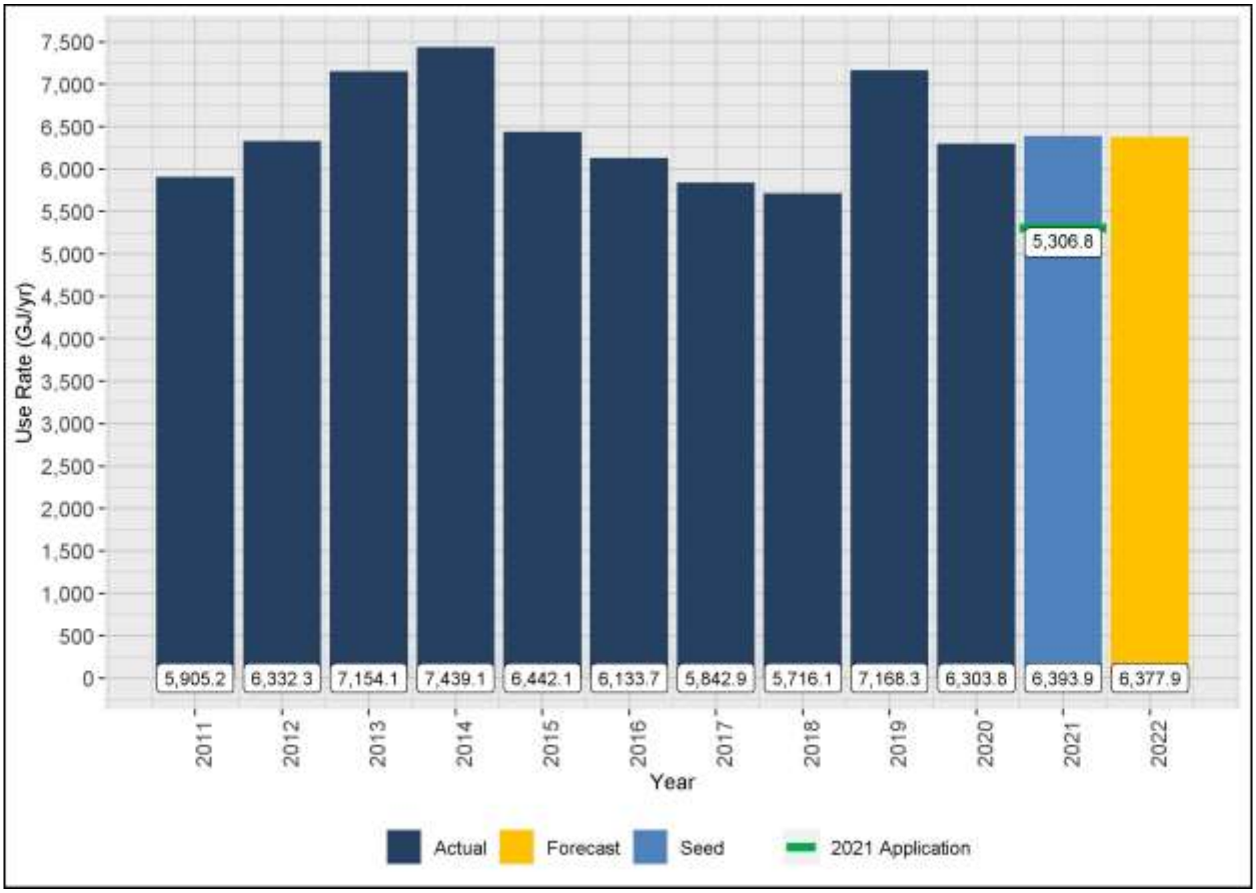
The UPC of RS 2 is forecast to continue a steady decline as shown in Figure 8-5 below.

Figure 8-5: UPC for Rate Schedule 2



For large commercial customers, the RS 3 UPC is forecast to increase relative to 2020 as shown in Figure 8-6 below. This is primarily due to the addition of the former RS 25 customer to this class. Please see Section 4.3.2.1 for more details related to this customer.

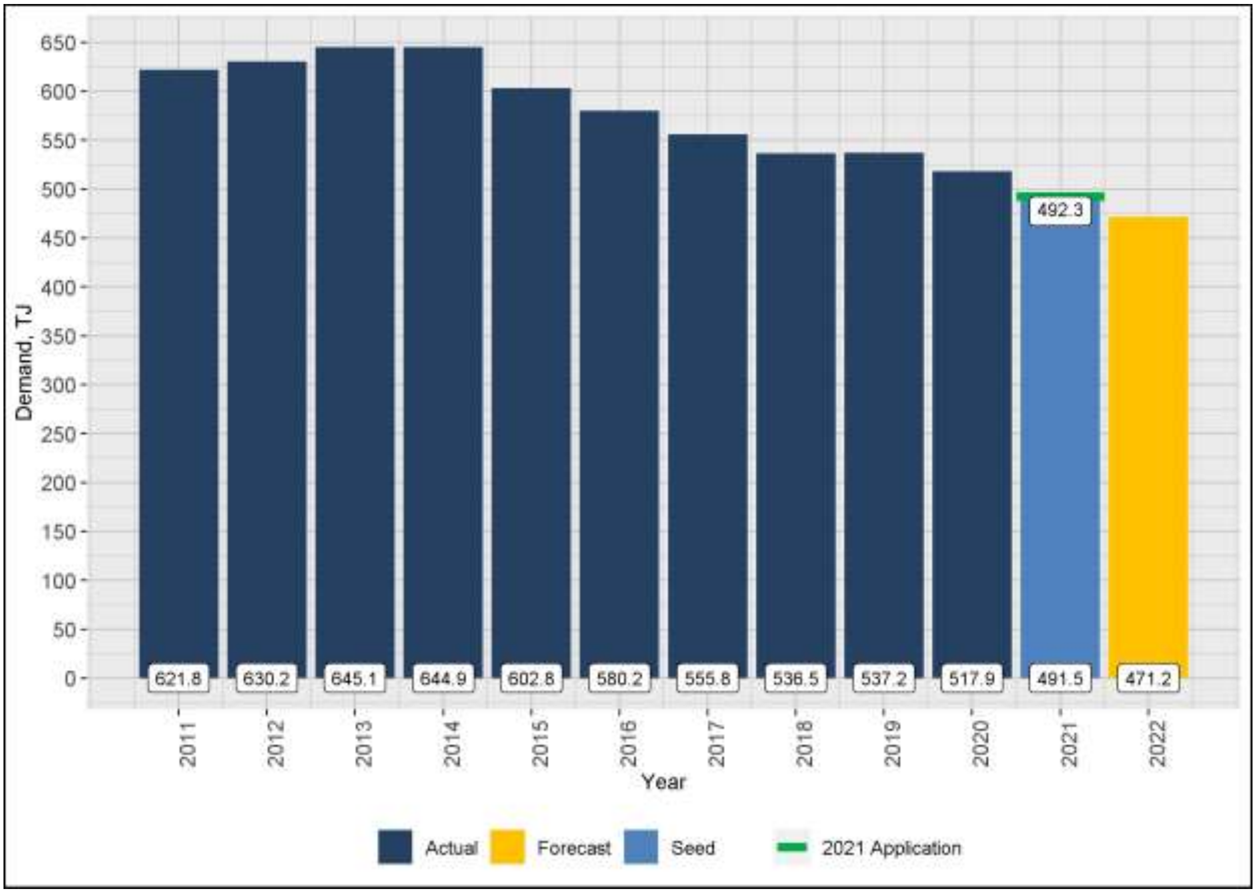
Figure 8-6: Rate Schedule 3 UPC



8.3.5 Demand Forecast

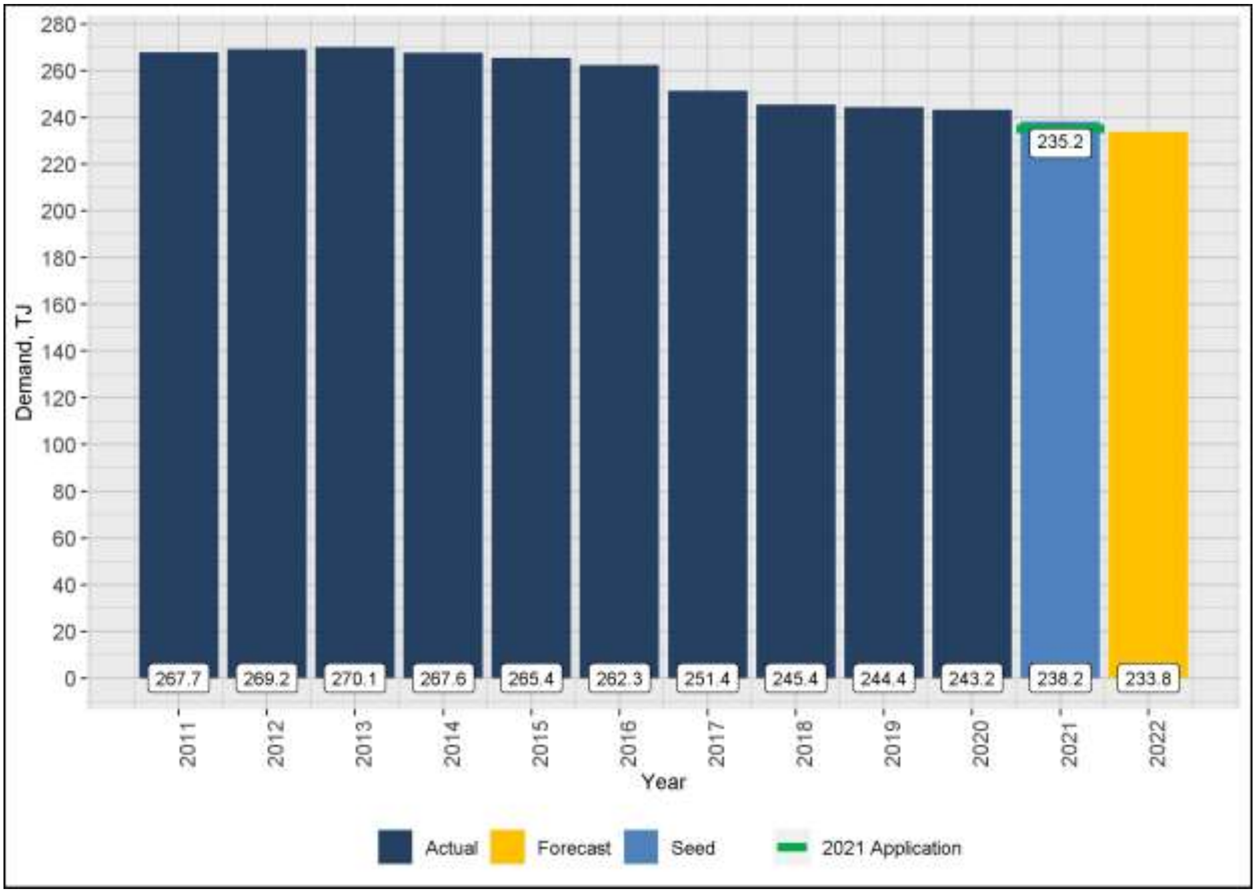
The energy demand forecast for each residential and commercial rate schedule is derived by multiplying the total forecast customers, including customer additions, by the average UPC forecast for each rate schedule. The total forecast energy demand is the sum of the energy demand for the individual rate schedules. The following Figure 8-7 illustrates the total historical and forecast normalized energy demand over the period 2011 to 2022. FEI is forecasting a decrease of approximately 20.3 TJs in FEFN's total energy demand for 2022 as compared to the 2021 Seed Year forecast.

Figure 8-7: Total Energy Demand



As seen in Figure 8-8 below, FEI is forecasting a decrease in residential energy demand in FEFN from 2021 to 2022. The decrease in demand is the result of decreasing use rates and decreasing customer counts.

Figure 8-8: Residential Energy Demand



As seen in Figure 8-9 below, the forecast demand for RS 2 is decreasing. This decrease in demand is the result of both declining customer counts and declining use rates.

Figure 8-9: Rate Schedule 2 Energy Demand

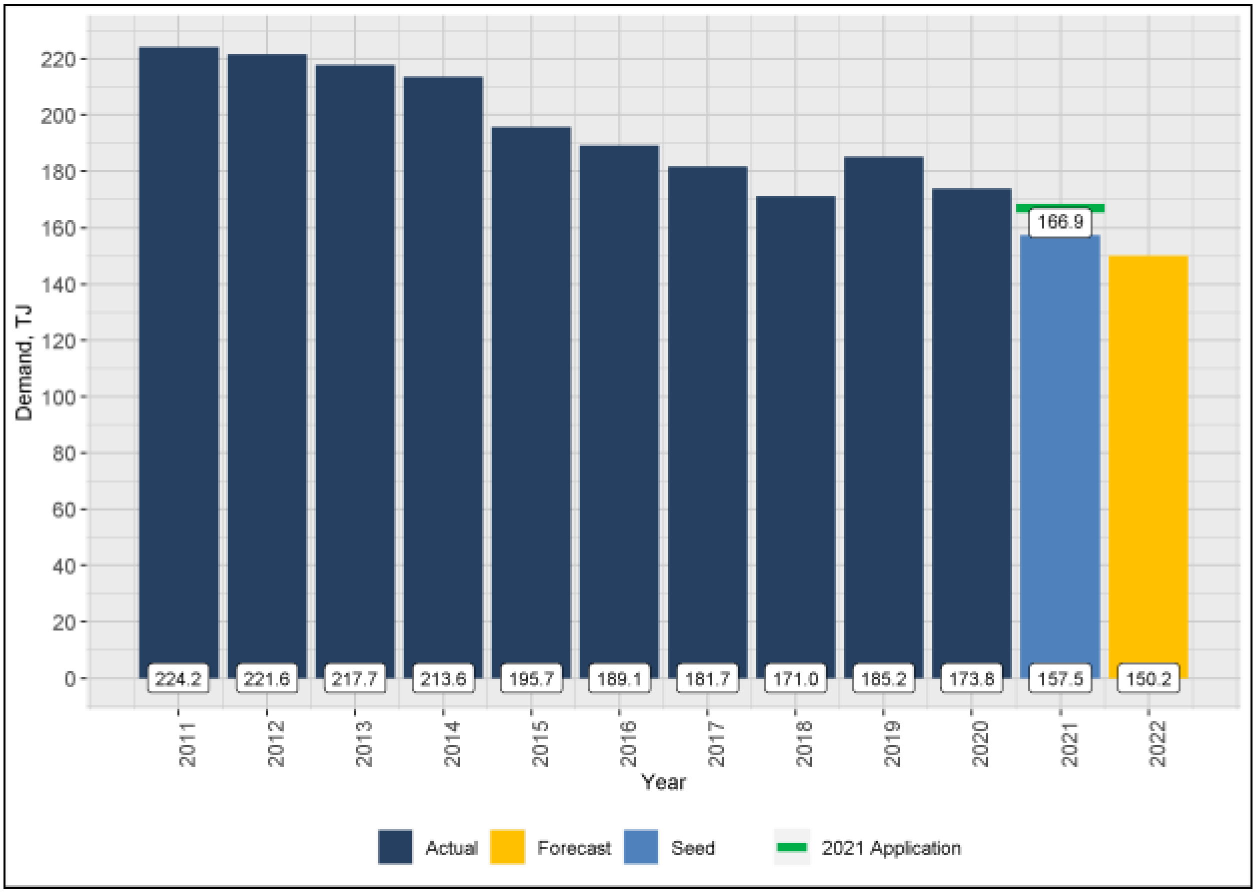
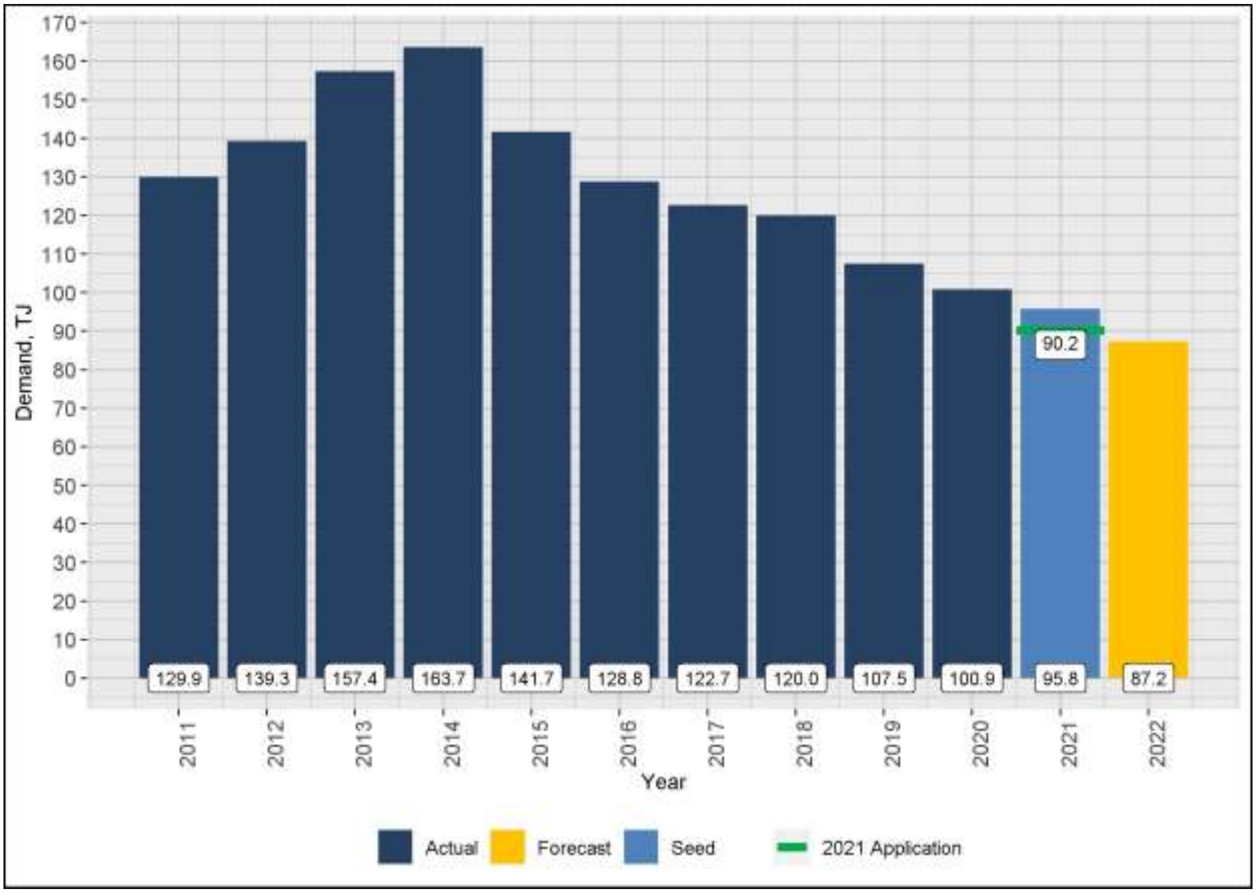


Figure 8-10 below shows the forecast demand for RS 3, which is decreasing. Despite a slight increase in the UPC forecast compared to 2020 as shown in Figure 8-6 above, RS 3 demand is forecast to decline due to a decline in the customer count.

Figure 8-10: Rate Schedule 3 Energy Demand



8.3.6 Revenue and Delivery Margin Forecast

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. FEFN has developed its forecast of revenues by applying the total energy forecast to the approved 2021 rates for each rate schedule.

Table 8-3 below summarizes the revenues for 2020 Actual, 2021 Projected and 2022 Forecast based on the approved 2021 rates, by customer rate classes.

Table 8-3: Forecast Sales Revenue ($000s)

Revenue ($000s)	2020 Actual	2021 Projected	2022 Forecast
Rate Schedule 1 - Residential	1,743	1,958	1,925
Rate Schedule 2 - Small Commercial	1,317	1,381	1,324
Rate Schedule 3 - Large Commercial	403	679	617
Rate Schedule 25 - Transportation	144	-	-
Total	**3,607**	**4,017**	**3,866**

The 2022 Forecast delivery margin is the forecast of 2022 revenues at the approved 2021 rates, minus the cost of gas. Table 8-4 below summarizes the delivery margins for 2020 Actual, 2021 Projected and 2022 Forecast by customer rate classes.

Table 8-4: Forecast Delivery Margin ($000s)

Delivery Margin ($000s)	2020 Actual	2021 Projected	2022 Forecast
Rate Schedule 1 - Residential	1,322	1,233	1,214
Rate Schedule 2 - Small Commercial	1,021	902	867
Rate Schedule 3 - Large Commercial	286	388	353
Rate Schedule 25 - Transportation	143	-	-
Total	**2,772**	**2,523**	**2,434**

8.3.7 Other Revenue

FEFN's Other Revenue includes two components – Late Payment Charges and Application Charges – as shown in Table 8-5 below and in Appendix E1, Schedule 19.

FEI implemented a number of customer relief measures in 2020 during the COVID-19 pandemic, including the suspension of Late Payment Charges. As a result, the 2020 Actual revenue from Late Payment Charges was lower than 2020 Approved. For 2021 Projected and 2022 Forecast, FEI expects the revenue from Late Payment Charges will return to a more normal level as FEI has reinstated the Late Payment Charges as of March 1, 2021. As such, FEI has forecast the revenue for Late Payment Charges based on the three-year average actuals from 2017 to 2019 (instead of the most recent three years of actuals from 2018 to 2020), adjusted proportionally with the forecast total revenues in 2022.

Table 8-5: 2020-2022 Other Revenue Components ($000s)

	Approved 2020	Actual 2020	Approved 2021	Projected 2021	Forecast 2022
Late Payment Charge	12	4	14	17	15
Application Charge	5	4	-	4	4
Total	**17**	**8**	**14**	**22**	**19**

8.4 OPERATING AND MAINTENANCE EXPENSES

8.4.1 Introduction and Determination of O&M

In 2022, O&M expenses are forecast to decrease slightly by approximately 0.4 percent from 2021 Approved primarily due to a reduction in the shared services fee and an increase in capitalized overhead, which is mostly offset by increases in vehicle costs, materials and supplies expenses, and contractor costs.

As explained in Section 4.3.1, the majority of FEFN's O&M expenses are comprised of the shared services fee allocated to FEFN from FEI.

To determine the FEFN-related O&M costs, both actual and forecast, the following process is used:

1. Determine the FEFN direct O&M costs. These costs consist of labour for the two employees noted below, vehicle usage, and materials and services used in direct system operations.

2. Allocate O&M costs from those FEI departments that provide functional support to FEFN. These shared services costs include charges related to Information Systems, Energy Supply and Resource Development, Transmission, Customer Service, Energy Solutions and External Relations, Engineering Services, Finance and Regulatory, Operations Support, Governance, Human Resources, Environment, Health and Safety, and Corporate (shown as "Fees and Administration Costs" in Table 8-6 below).

   Starting with 2008, the BCUC approved the use of customers as the allocation factor to determine the Shared Services for FEFN, stating:[50]

   > Shared Services received by TG Fort Nelson from TGI for 2008 are to be allocated to the Company on the basis of customers…

   Since that time, the Shared Services allocation has been based on FEFN's customers as a percentage of FEI's customers.

   For 2022, the combined customer total[51] for FEI and FEFN is forecast to be 1,070,804, while the FEFN portion is 2,314 (as shown in the financial schedules in Appendix E1, Schedule 15, Line 13, Column 9). Therefore, the allocation factor which has been used for 2022 rates is 0.216 percent.

   The 2022 O&M costs used in the allocation are consistent with the basis used in calculating the approved 2021 shared services fee. The calculation uses the gross O&M FEI is forecasting for 2022, taking into consideration the formula drivers approved under the MRP as well as the forecast of O&M items that are excluded from the formula calculation.

3. Apply an overhead capitalization rate to the sum of the direct and allocated O&M costs to calculate the net O&M costs. As discussed previously, FEI's capitalized overhead rate was approved to change from 12 percent to 16 percent as part of the MRP Decision and Order G-165-20, and FEI is requesting to adopt this change in capitalized overhead for FEFN as part of this Application. Therefore, for the purposes of calculating FEFN's O&M costs for 2022, the overhead capitalization rate has been increased from 12 percent to 16 percent.

[50] Order G-27-08.
[51] 12-months average.

8.4.2 Forecast O&M

Table 8-6 below provides a resource view of the direct and allocated O&M costs for the years 2020 through 2022. The O&M forecast for 2022 was determined in accordance with the methodology described above.

Table 8-6: FEFN O&M ($000s)

Particulars	2020 Approved	2020 Actual	2021 Approved	2021 Projected	2022 Forecast
M&E Costs	$ 19	$ 7	$ 18	$ 18	$ 18
IBEW Costs	331	242	242	250	255
Labour Costs	**350**	**249**	**260**	**268**	**273**
Vehicle Costs	45	32	26	45	46
Employee Expenses	20	9	12	6	6
Materials and Supplies	8	6	2	18	19
Fees and Administration Costs	535	562	587	586	576
Contractor Costs	22	10	15	35	36
Facilities	37	39	34	25	26
Recoveries & Revenue	(2)	(1)	(1)	(6)	(6)
Non-Labour Costs	**665**	**657**	**675**	**709**	**703**
Total Gross O&M Expenses	**1,015**	**906**	**935**	**977**	**976**
Less: Capitalized Overhead	(122)	(122)	(112)	(112)	(156)
Total O&M Expenses	**$ 893**	**$ 784**	**$ 823**	**$ 865**	**$ 820**

As shown in Table 8-6 above, the 2022 Forecast Total O&M expense is approximately $3 thousand less than 2021 Approved and approximately $45 thousand less than 2021 Projected. Major changes in O&M are discussed below.

Labour Costs

As explained in Section 4.3.1, the Operations staffing at FEFN includes two full-time IBEW employees supported periodically by specialized pressure control technicians and management staff in Prince George.

The IBEW labour costs forecast for 2022 are expected to be consistent with the Projected 2021 amounts plus inflation, which is based on FEI's 2022 net inflation factor of 3.324 percent.[52]

Vehicle Costs

The 2021 Projected vehicle costs are estimated to be higher than 2021 Approved primarily due to an increase in repair costs for the vehicles used by the FEFN staff. FEI expects this level of repair costs will continue in 2022, which is reflected in the 2022 Forecast, plus an inflationary increase assumed at FEI's 2022 net inflation factor of 3.324 percent.

Materials and Supplies, and Contractor Costs

The 2021 Projected costs of $18 thousand for material and supplies and $35 thousand for contractor costs are estimated to be higher than 2021 Approved by approximately $16 thousand and $20 thousand, respectively. The increase for 2021 Projected is primarily due to the increased service required for the distribution system which is reflected in the increased contractor costs and materials needed for the servicing. FEI expects the level of servicing required will continue in 2022, which is reflected in the 2022 Forecast, plus an inflationary increase assumed at FEI's 2022 net inflation factor of 3.324 percent.

Fees and Administration Costs

Fees and Administration costs consist of the shared services fee from FEI. The 2022 Forecast shared services fee is $576 thousand, which is a decrease from the 2021 Approved level of $587 thousand. The decrease is primarily due to the lower allocation factor based on the average customer count between FEFN and FEI. Table 8-7 below provides a breakdown of the 2020, 2021 and 2022 shared service fee calculations.

[52] FEI's net inflation factor is based on a 49 percent / 51 percent split between CPI and AWE, and a productivity factor of 0.5 percent, as presented in FEI's Annual Review for 2022 Delivery Rates Application.

Table 8-7: FEFN Shared Service Fee ($000s)

	2020 Approved	2020 Actuals	2021 Approved	2021 Projected	2022 Forecast
FEI Gross O&M	287,858	312,407	327,543	327,543	329,948
Less: O&M not subject to allocation [1]	(57,255)	(62,463)	(62,847)	(60,969)	(62,996)
O&M Allocation Base	230,603	249,943	264,696	266,574	266,952
Multiplied by Allocation Factor	0.00232	0.00225	0.00222	0.00220	0.00216
Shared Services Fee	535	562	587	586	576
Average Number of Customers					
FEFN	2,409	2,354	2,343	2,331	2,314
FEI	1,036,685	1,043,610	1,053,292	1,057,078	1,068,490
Total	1,039,094	1,045,964	1,055,635	1,059,409	1,070,804
Allocation Factor (FEFN/Total)	0.00232	0.00225	0.00222	0.00220	0.00216

Notes to table:

1 Distribution common costs that do not provide functional support to Fort Nelson accounted for as direct costs.

Capitalized Overhead

Pursuant to the MRP Decision and Order G-165-20, FEI's capitalized overhead rate has been approved to change from 12 percent to 16 percent. Consistent with past FEFN revenue requirements, FEFN requests approval to adopt the changes approved for FEI. As such, for the purposes of calculating the 2022 revenue requirement for FEFN, FEI has used the more recent capitalized overhead rate of 16 percent. The change in capitalized overhead rate from 12 percent to 16 percent results in an increase to capitalized overhead from $112 thousand (2021 Approved) to $156 thousand (2022 Forecast).

8.5 *TAXES*

8.5.1 Introduction

This section discusses FEFN's forecast property taxes and income taxes, which have been forecast on a basis consistent with prior years. In 2022, property taxes and income taxes are forecast to increase by 5.3 percent and 21.4 percent, respectively, from 2021 Approved. Any variances from the forecast of property taxes included in rates will be recorded in the Property Tax Variance deferral account.

8.5.2 Property Tax

Details of 2020, 2021 and 2022 property tax expense are provided in the following table.

Table 8-8: Property Tax Expense ($000s)

Asset Type	2020 Approved	2020 Actuals	2021 Approved	2021 Projected	2022 Forecast
Transmission Assets	$ 0.5	$ 28	$ 30	$ 28	$ 29
Distribution Assets	77	79	79	82	84
General Assets	13	11	11	10	11
In-Lieu	36	33	30	30	34
OGC Fees	1	1	1	2	2
Total Property Taxes	$ 128	$ 152	$ 151	$ 152	$ 159
Forecast Change from 2021 Approved					5.3%

The 2021 Projected property taxes are consistent with 2021 Approved.

The 2022 Forecast is estimated to be approximately 5.3 percent higher than 2021 Approved, primarily due to an increase in pipeline additions along with a 3 percent increase in pipeline assessment rates, and also the forecast increase in revenues resulting in higher in-lieu taxes. As grants in-lieu of taxes are based on a fixed percentage of revenues, the overall increase in revenues reported to municipalities increases the grants in-lieu of taxes due.

8.5.3 Income Tax

FEI is subject to corporate income taxes imposed by the Federal and BC governments, and as such appropriately includes these costs in calculating FEFN's revenue requirements. Income taxes have been calculated using the flow-through (taxes payable) method, consistent with BCUC approved past practice, at the corporate tax rate of 27 percent. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax enacted legislation.

As approved by Order G-53-94, deferred charges, to the extent they are tax deductible, and deferred credits, to the extent they are taxable, are treated on a net-of-tax basis. Under the net-of-tax method, the gross addition to a deferral account is offset by the tax savings or tax cost (as the case may be) calculated at the prevailing income tax rate for the current year.

Income tax for 2022 is forecast to be $85 thousand (Appendix E1, Schedule 20), an increase of $15 thousand (or 21.4 percent) when compared to 2021 Approved. The increase is primarily due to an increase in FEFN's taxable income as a result of the growth in rate base, the forecast increase of amortization expense, and the forecast decease in removal costs.

8.6 RATE BASE AND CAPITAL ADDITIONS

8.6.1 Introduction

The 2022 mid-year average rate base amount is forecast to be $13,186 thousand, as shown in Table 8-9 below and Appendix E1, Schedule 2, Line 24, Column 3. This amount reflects the investment by the Company in utility assets necessary to provide service to FEFN customers.

The table below sets out FEFN's 2020 through 2022 rate base.

Table 8-9: Rate Base ($000s)

	Approved 2020	Actual 2020	Approved 2021	Projected 2021	Forecast 2022
Net Plant in Service, Mid-Year	12,105	11,795	12,365	12,118	12,827
Adjustment to 13 - Month Average	-	(38)	-	-	-
Work in Progress, No AFUDC	121	181	77	181	181
Unamortized Deferred Charges	66	(17)	(20)	(27)	94
Cash Working Capital	45	42	55	49	49
Other Working Capital	27	35	26	35	35
Utility Rate Base	**$ 12,364**	**$ 11,998**	**$ 12,503**	**$ 12,356**	**$ 13,186**

The growth in rate base for the forecast period is largely attributable to capital additions. Each of the main components of rate base (plant balances, deferral accounts, and working capital) is discussed separately below.

8.6.2 Net Plant In-Service (NPIS)

The mid-year NPIS balance of $12,827 thousand in 2022 shown in Table 8-9 above is the sum of the mid-year average of the gross plant in-service, contributions in aid of construction (CIAC), and accumulated depreciation and amortization related to these two items.

8.6.2.1 Gross Plant In-Service (GPIS)

The opening GPIS balance of $18,369 thousand in 2022 (Appendix E1, Schedule 2, Line 1, Column 3) is made up of the actual 2020 ending GPIS balance of $17,295 thousand[53] plus 2021 Projected plant additions, less retirements. Plant additions are comprised of capital expenditures adjusted for opening and closing work in progress (WIP), plus allowance for funds used during construction (AFUDC) and overheads capitalized, where applicable. Table 8-10 below summarizes the FEFN plant additions for 2020 through 2022.

[53] FEFN 2020 BCUC Annual Report, page 2, Line 7, Column 4.

Table 8-10: Summary of Gross Plant Additions ($000s)[54]

	Approved 2020	Actual 2020	Approved 2021	Projected 2021	Forecast 2022
Intangibles	46	45	44	45	42
Transmission	5	-	229	371	12
Distribution	463	161	473	573	898
General	49	27	59	50	53
Total	**563**	**233**	**805**	**1,039**	**1,005**

The 2021 Projected capital additions are approximately $234 thousand higher than the 2021 Approved additions. This is a result of some distribution projects that were not completed in 2020 and therefore were delayed to 2021 (as evidenced by the lower 2020 Actual distribution plant additions compared to 2020 Approved). FEI did not anticipate these delays when forecasting FEFN's 2021 capital additions as part of the 2021 Deferral Account Application; therefore, the 2021 Projected capital additions presented in this Application are higher than the 2021 Approved capital additions. However, FEI notes that for 2020 and 2021 combined, capital additions are generally in line with approved amounts (the total 2020 and 2021 Approved amount was $1,368 thousand compared to the total 2020 and 2021 Actual/Projected amount of $1,272 thousand), with a variance of approximately $96 thousand.

A description of the major changes in plant additions for 2022 follows.

Intangible Plant

Since 2017, FEI has been allocating intangible capital costs to FEFN. The amount of the allocation to FEFN's intangible plant in 2022 is $42 thousand, related to the purchase and sustainment of system computer software.

Transmission Plant

The 2022 Forecast additions to transmission plant are less than 2021 Projected.

As explained in Section 4.3.3, for 2021, FEI plans to install new telemetry at the Fort Nelson Control Station for monitoring the operations of the station and compliance with industry standards. The Fort Nelson Control Station controls the pressure of gas flowing from Enbridge into FEI's transmission system. FEI also plans to install a gradient control mat at the Fort Nelson Control Station to protect workers from induced voltages on the above ground piping from the nearby power facility. Table 8-11 below provides the breakdown of the two projects based on the current projected capital additions. FEI notes the 2021 Projected capital additions have increased from 2021 Approved by approximately $142 thousand. The increase is primarily due to additional consulting costs for engineering and design as well as a change in scope of work to include additional hydrovax services for safe excavation and additional fencing for the site work. The additional consulting costs and scope of work were not anticipated when the

[54] Table excludes AFUDC and capitalized overhead. The forecast capital additions with AFUDC and capitalized overhead for 2022 are $1,161 thousand (Appendix E1, Schedule 4, Line 38, Column 6).

2021 Approved amount was developed. FEI is currently projecting the majority of the capital additions to occur in 2021 ($371 thousand for 2021 Projected) with the remaining capital additions related to the site clean-up work to occur in 2022 ($12 thousand for 2022 Forecast). These site clean-up costs are the only capital additions forecast for transmission plant in 2022.

Table 8-11: Summary of Transmission Projects with Capital Additions in 2021 and 2022 ($000s)

Transmission Projects	2021 Approved	2021 Projected	2022 Forecast
Fort Nelson Control Station - Install Telemetry	185	278	10
Fort Nelson Control Station - Install Gradient Control Mat	44	93	2
TOTAL ($000s)	**229**	**371**	**12**

Distribution Plant

Table 8-12 below summarizes the projects for distribution plant with capital additions in 2021 and 2022.

Table 8-12: Summary of Distribution Projects with Capital Additions in 2021 and 2022 ($000s)

Distribution Projects	2021 Approved	2021 Projected	2022 Forecast
Growth Related Distribution Capital	-	14	14
Main Replacements/Renewal Program	329	355	167
Recreation Centre District Station - Upgrade	103	-	623
Main Alteration - Tamarack Crescent	-	150	-
Cathodic Protection	-	5	55
Other Misc Sustainment Capital & Service Alteration	41	49	39
TOTAL ($000s)	**473**	**573**	**898**

FEI provides a description of each distribution project with forecast capital additions in 2022 as well as an explanation for the major variances between 2021 Approved and Projected capital additions as follows:

- The 2022 Forecast Growth-related distribution capital additions are $14 thousand, which is consistent with 2021 Projected, and include expenditures related to new mains, services and meters.
- FEI continues to incur capital additions for the continuation of the distribution main renewal program. This program, which is to address older steel pipe for which FEI has concerns regarding its condition, is ongoing and has been discussed in previous FEFN RRAs. The 2022 Forecast capital additions are $167 thousand. FEI expects the mains renewal/replacement program will be completed in 2023.
- As first discussed in FEFN's 2019-2020 RRA, FEI is undertaking a project to upgrade FEFN's Recreation Centre District Station to address deficiencies with respect to pipe, valve, filter, and meter rating and/or capacity. These upgrades will ensure compliance

with Company and industry standards for safety and reliability. As the City of Fort Nelson has advised that it is willing to create a formal land agreement for the existing site, this will allow FEFN to upgrade the existing station rather than installing a new station elsewhere. As directed in Order G-78-21, FEI provides the current scope, timing and capital additions for this project in Table 8-13 below. Due to the original uncertainty regarding the location of the station, FEI was delayed in commencing the project; thus, the $103 thousand forecast to be spent in 2021 as part of the FEFN 2021 Deferral Account Application is now forecast to be spent in 2022. FEI expects the construction of the project to be completed in 2022, with some minor expenditures related to site clean-up occurring in 2023.

Table 8-13: Scope of Work and Timing of Capital Additions for the Recreation Centre District Station Project ($000s)

Recreation Centre Station Capital Additions	2022 Forecast	2023 Forecast
Project Management	$ 58	$ 20
Design	108	-
Procurement	214	-
Prefabrication	31	-
Construction/Commission	212	-
Site Cleanup	-	12
Total ($000s)	**$ 623**	**$ 32**

- FEFN is undertaking a main alteration project near Tamarack Crescent in 2021 with capital additions projected to be approximately $150 thousand. This involves replacing 425 m of NPS2 main that is currently located in the backyards of many residential lots. Over the years, vegetation and other structures and encumbrances have been located over top of the main and it is now very difficult to access and to perform leak surveys. Replacing this main with one on the front side of the residences and running new services will eliminate the hazards associated with having the main in the backyards. This project was not originally planned to be undertaken in 2021; therefore, FEI did not include these capital additions as part of the 2021 Deferral Account Application.
- FEI is projecting capital additions of approximately $5 thousand in 2021 and forecasting approximately $55 thousand in 2022 for replacement of cathodic protection rectifiers. Cathodic protection rectifiers are used to control corrosion of the steel surface of the pipeline.
- Other miscellaneous sustainment projects related to distribution plant (distribution system integrity) and various service line alteration requests are projected to be $49 thousand in 2021 and forecast to be $39 thousand in 2022, which is similar to the 2021 Approved amount of $41 thousand.

General Plant

The 2021 Projected and 2022 Forecast of capital additions for General Plant are $50 thousand and $53 thousand, respectively, which are consistent with 2021 Approved. The 2022 Forecast General Plant additions are primarily related to an allocation from FEI for hardware and software costs of approximately $18 thousand, as well as approximately $10 thousand for small tools and equipment for Fort Nelson operations, and approximately $25 thousand for facility upgrades related to safety system, lighting, and finishing.

8.6.2.2 Contributions in Aid of Construction (CIAC)

Gross CIAC is composed of opening contributions plus additions and less retirements throughout the year. There are no CIAC additions forecast for 2022, and as such the year-end CIAC amount of $1,340 thousand in 2022 (Appendix E1, Schedule 6, Line 4, Column 7) is unchanged from the 2020 actual ending balance[55].

8.6.2.3 Accumulated Depreciation

FEFN's rate base includes both the accumulated depreciation of plant in service, and accumulated amortization of CIAC. Both are increased through depreciation and amortization expense, and decreased through retirements. Depreciation for 2022 has been calculated starting January 1 of the year after the assets are placed in service, which is the currently accepted treatment for FEFN.

Consistent with past FEFN RRAs, FEFN adopts FEI's changes to depreciation and net salvage rates. FEI's most recent deprecation study was completed in 2017 and was approved as part of the MRP Decision and Order G-165-20. FEI is seeking approval in this Application to adopt the depreciation and net salvage rates from FEI's most recent depreciation study. FEFN's assets were included with FEI's assets in the data used to prepare the depreciation study, as such, the recommended depreciation and net salvage rates are applicable to FEFN. The change in depreciation rates and net salvage rates result in a decrease of $30 thousand (Appendix E1, Schedule 1, Line 11, Column 2) and an increase of $27 thousand (Appendix E1, Schedule 1, Line 17, Column 2), respectively, which results in a net reduction to FEFN's 2022 revenue deficiency.

8.6.3 Work in Progress

Consistent with past practice, Work in Progress included in Rate Base represents construction work in progress for projects that are shorter than three months in duration and less than $100 thousand. Projects over this threshold attract AFUDC, and are not included in rate base until they are available for use, at which time AFUDC is no longer charged to the capital project. The 2021 Projected and 2022 Forecast of Work in Progress with no AFUDC are based on the 2020 Actual amount of $181 thousand.

[55] Historically, FEFN CIAC additions have been minimal in dollar value and are difficult to predict.

8.6.4 Deferral Accounts

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[56] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Appendix E1, Schedules 8 and 9, FEI has classified its existing rate base deferral accounts and non-rate base deferral accounts, respectively, for FEFN in accordance with this classification.

The mid-year balances of the deferral accounts included in rate base are provided in the table below.

Table 8-14: Deferral Balances included in Rate Base ($000s)

	2020 Approved	2020 Actual	2021 Approved	2021 Projected	2022 Forecast
Forecasting Variance Account					
Revenue Stabilization Adjustment Mechanism (RSAM)	36	(30)	(179)	(225)	(212)
Interest on RSAM	1	2	-	(1)	(1)
Gas Cost Reconciliation Account (GCRA)	-	(35)	52	70	31
Property Tax Deferral	(24)	4	24	24	20
Interest Variance	-	(11)	(6)	(14)	(9)
Benefits Matching Accounts					
Demand-Side Management (DSM)	228	143	246	206	319
2019-2020 Revenue Requirement Application	15	(1)	(8)	(8)	-
2017 Rate Design Application	14	28	22	22	13
Gains and Losses on Asset Disposition	52	52	40	40	29
Net Salvage Provision/Cost	(292)	(186)	(215)	(173)	(164)
FEFN Common Rates and 2022 Revenue Requirement Application Costs	-	-	-	19	64
Billing System Costs for FEFN Rate Changes	36	9	4	4	2
Other Deferral Accounts					
COVID-19 Customer Recovery Fund	-	8	-	9	2
Total Mid-Year Deferred Charges in Rate Base	66	(17)	(20)	(27)	94

In the following section, FEI requests approval of one new deferral account for FEFN to capture the costs of this Application and associated regulatory process. FEI also provides updates on three existing FEFN deferral accounts.

8.6.4.1 New Deferral Account

FEI requests approval of a new rate base deferral account – the FEFN Common Rates and 2022 Revenue Requirement Application Costs deferral account. Table 8-15 below addresses the considerations identified in the Regulatory Account Filing Checklist.

[56] Log No. 53608, Appendix B.

Table 8-15: Deferral Account Filing Considerations

Item	Consideration	Determination FEFN Common Rates Application Costs
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	FEI requests the establishment of a new deferral account, the FEFN Common Rates and 2022 Revenue Requirement Application Costs deferral account, to capture the costs related to this Application and the related regulatory proceeding.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The requested account is a regulatory proceeding cost account, which is routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term is for approximately one year which encompasses the preparation and filing of the Application, the review of the Application by the BCUC, and the time required to update the billing system.
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of deferral accounts for regulatory proceedings, the costs of regulatory proceedings would have to be forecast as an O&M expense. FEI considers this to be a more cumbersome, less efficient and less accurate means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself.

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

Item	Consideration	Determination FEFN Common Rates Application Costs
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	Generally FEI amortizes the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits, while also factoring in the rate impacts to customers.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	The FEFN Common Rates and 2022 Revenue Requirement Application Costs deferral account is proposed to be a rate base deferral account. Rate base deferral accounts are included in rate base and are therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of the present proceeding.

FEI expects to incur costs related to this Application estimated at approximately $50 thousand in 2021 and $75 thousand in 2022 (on a pre-tax basis). Costs incurred will consist of external legal fees, intervener and participant funding costs, BCUC costs, stakeholder consultation costs (e.g. virtual town hall), required public notifications, and miscellaneous facilities, stationery and supplies costs.

As explained in Section 7.1.4.3, FEI is not proposing an amortization period for the FEFN Common Rates and 2022 Revenue Requirement Application Costs deferral account at this time. FEI proposes to address amortization of this deferral account when filing for 2023 delivery rates, either as part of the FEI 2023 Annual Review or as part of a standalone FEFN 2023 revenue requirement application.

8.6.4.2 Existing Deferral Accounts

FEI provides an update on three existing FEFN deferral accounts.

FEFN 2021 Revenue Surplus Deferral Account

As part of the FEFN 2021 Deferral Account Decision[57], FEI was approved to establish the FEFN 2021 Revenue Surplus deferral account to capture the forecast 2021 revenue surplus of $132 thousand and any BCUC direct costs related to the review of the application. The account was approved as non-rate base attracting interest based on a WACC return. The 2022 ending after-tax balance in the deferral account is a credit of $94 thousand. This balance is comprised of the

[57] Order G-78-21.

approved 2021 revenue surplus of $132 thousand, less FEI's external legal costs and public notification costs related to the review of the application which total $14 thousand, less income taxes of $32 thousand, plus carrying charges accrued on the deferral account balance of $3 thousand in 2021 and $5 thousand in 2022.

As explained in Section 7.1.4.4, FEI proposes to utilize the FEFN 2021 Revenue Surplus deferral account in the implementation of the Proposed Common Rate Option in 2023 to mitigate the rate impact for residential FEFN customers of moving to common rates. If common rates are not approved, FEI would apply for disposition of the FEFN 2021 Revenue Surplus deferral account as part of FEFN's next revenue requirement application.

COVID-19 Customer Recovery Fund Deferral Account

In June 2020, FEI received approval through Order G-132-20 to establish the COVID-19 Customer Recovery Fund Deferral Account in rate base to record three items:

1. any bill payment deferrals provided to customers due the COVID-19 pandemic and subsequent payments of those deferred amounts;
2. any bill credits provided to customers due to the COVID-19 pandemic; and
3. any unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic, which will be tracked separately by rate schedule.

FEI accordingly established a separate COVID-19 Customer Recovery Fund Deferral Account for Fort Nelson to separately record the customer enrollments from Fort Nelson in the COVID-19 relief program related to the three items above.

As Table 8-14 above shows, the Forecast 2022 mid-year balance in the COVID-19 Customer Recovery Fund Deferral Account is $2 thousand. This balance is related to bill credits, as the forecast assumes all bill deferrals are repaid by the end of 2021.

If common delivery rates are approved, FEFN's COVID-19 Customer Recovery Fund Deferral Account will be consolidated with FEI's deferral account, as explained in Section 7.1.4.1. If common delivery rates are not approved and FEFN continues to have separate delivery rates from FEI, FEI will propose an amortization period as part of FEFN's next revenue requirement application.

Fort Nelson First Nation Right-of-Way Agreement

As approved through Order G-97-15, a non-rate base deferral account was created to capture the actual costs incurred to complete the Fort Nelson First Nation Right-of-Way Agreement. Further, the Order stated that disposition of this deferral account should be requested in FEFN's next revenue requirement proceeding.

As part of the 2017-2018 RRA, 2019-2020 RRA, and the 2021 Deferral Account Application, and approved through Orders G-162-16, G-48-19 and G-78-21, respectively, FEI proposed to continue to record actual costs in this deferral account and apply for disposition of this account in an upcoming revenue requirement proceeding due to ongoing negotiations in finalizing the agreement.

Negotiations with Fort Nelson First Nation continue to stall due to personnel priority changes within the band and the impacts of the COVID-19 pandemic. FEI continues to reach out to the nation to restart the negotiations. No costs have accrued to the deferral account since 2018 other than approved financing.

As the negotiations in finalizing this agreement are still continuing and there remains uncertainty about the ultimate dollar value to be spent, FEI proposes to continue to record the actual costs in the existing deferral account and apply for disposition of this account in a future proceeding once the final costs are known.

8.6.5 Cash and Other Working Capital

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

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days, and are supported by a Lead/Lag Study. In the MRP Decision and Order G-165-20, FEI was approved to modify the lead/lag days as set out in the Lead/Lag Study filed as part of the MRP application.

Consistent with the treatment in past FEFN revenue requirements, FEI requests approval to adopt the modified lead/lag days approved by Order G-165-20 for FEFN. FEI has utilized the modified lead/lag days in the calculation of FEFN's cash working capital for 2022, resulting in $60 thousand (Appendix E1, Schedule 10, Line 2, Column 3) of cash working capital being added to FEFN's rate base for 2022.

Other working capital includes inventory of materials and supplies, and employee loans and withholdings, which are calculated based on historical levels.

8.7 *FINANCING AND CAPITAL STRUCTURE*

8.7.1 Introduction

FEI has forecast FEFN's share of FEI's debt financing costs for 2022 using the same method as has been accepted in the past. The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the BCUC from time to time. FEFN shares the same capital structure and return on equity (ROE) as FEI. FEI's currently approved ROE is 8.75 percent and currently approved common equity percentage is 38.5 percent.

8.7.2 Financing Costs

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

Long-Term Debt

FEFN receives an allocation of FEI's total long-term debt based on rate base. As set out in FEI's Annual Review for 2022 Delivery Rates application, FEI plans to issue long-term debt of approximately $200 million in 2022 to repay existing indebtedness and to finance the Company's capital expenditure program. The FEFN long-term debt allocation is $7.844 million (Appendix E1, Schedule 23, Line 28, Column 5) in 2022.

Short-Term Debt

The short-term debt for FEFN represents the difference between its long-term debt allocation from FEI and 61.5 percent of rate base. Interest rate forecasts reflect FEI's methodology as discussed below.

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

The 3-month T-Bill rate is projected to increase from 0.13 percent in 2021 to approximately 0.47 percent in 2022. The short-term borrowing rate forecast is shown in Table 8-16 below.

Table 8-16: Short Term Interest Rate Forecasts

FEI Short Term Interest Rate	2021	2022
3-Month T-Bill Rate1	0.13%	0.47%
Spread to CDOR	0.39%	0.39%
CDOR Rate	0.52%	0.86%
Spread to CP	-0.32%	-0.32%
CP Dealer Commission	0.10%	0.10%
ST Interest Rate on Credit Facilities	0.30%	0.64%
Fixed Financing Fees2		
Standby Fee on Undrawn Credit	0.90%	1.12%
Renewal Fee on Undrawn Credit	0.32%	0.40%
Other Financing Fees	0.12%	0.15%
ST Interest Rate on Fixed Financing Fee	1.34%	1.67%
FEI Short Term Rate (Rounded)	**1.64%**	**2.31%**

Notes to table:

[1] 3-Month T-Bill Rate for 2022 is a weighted average rate based on forecasts provided by Canadian Chartered banks in June 2021.

[2] Fixed financing fees represent the costs of maintaining the $700 million credit facility and letter of credit facility, which are fixed fees regardless if FEI draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

[3] A standby fee of 16 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FEI will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

Due to the uncontrollable nature and forecasting uncertainty associated with interest rates, FEFN has an Interest Rate Variance deferral account that captures the impact on interest expense of interest rate variances and variances in the amount of debt as compared to forecast.

8.8 *CONCLUSION ON 2022 DELIVERY RATES*

FEI requests approval of an effective delivery rate increase for FEFN of 3.41 percent, effective January 1, 2022. FEI has included a detailed analysis of the 2022 revenue requirement components supporting the FEFN delivery rate increase. The forecast delivery rate increase for 2022 is primarily driven by a decrease in energy demand and increased costs related to necessary capital improvement and sustainment spending to continue to provide safe, reliable and continuous service to FEFN customers. These drivers of the delivery rate increase, and the continued pressure on FEFN customer delivery rates created by these drivers, are a key consideration supporting FEI's Proposed Common Rate Option. If the Proposed Common Rate Option is approved, this will be the final year that delivery rates will be set separately for FEFN, as customers will be transitioned to common rates effective January 1, 2023.

9. CONCLUSION

Implementing common rates for FEFN as proposed in this Application will benefit customers over the long term and will eliminate the disproportionate regulatory cost and effort associated with preparing and reviewing the separate regulatory filings required for FEFN, including the costs and time related to the public hearing processes.

Over the past decades, FEI has sought to consolidate its various divisions and service areas under one legal entity and to unify these service areas through common delivery and commodity rates. With the BCUC's approval in 2020 to implement common commodity rates for Revelstoke customers, the establishment of common rates throughout all service areas is almost complete. The remaining outlier is Fort Nelson, a region which currently serves approximately 2,400 customers who consume approximately 0.5 PJs of natural gas annually.

FEI considered a number of key factors in its determination that now is the appropriate time to apply to move FEFN to common rates. It has become increasingly less beneficial to Fort Nelson customers to maintain a separate rate base and rates, and, as was outlined in the FEFN 2019-2020 RRA, it is now negatively impacting commercial customers as that class of customers has higher rates than FEI's other service areas. FEFN's demand has been declining in recent years and is expected to continue to decline. This decline, coupled with ongoing capital expenditure requirements to maintain FEFN's system, has resulted in significant delivery rate volatility over the past 10 years and on average greater delivery rate increases for FEFN than for FEI.

FEFN is already integrated with the larger FEI utility and, given the large portion of shared services making up FEFN's revenue requirement, current delivery rate differences are not reflective of true regional differences in the cost to serve. A move to common rates will, therefore, more appropriately reflect the operational and financial reality of the Fort Nelson service area.

FEI developed four key Objectives for assessing the various common rate options, and based on these Objectives, determined that transitioning FEFN customers to common delivery and cost of gas rates, and amalgamating FEFN and FEI's gas cost portfolios such that FEFN will be charged 5 percent of FEI's midstream rate, best meets the Objectives and provides benefits to customers. FEI proposes to implement the Proposed Common Rate Option as of January 1, 2023, with a 10-year phase-in of common delivery rates for FEFN's residential customers.

As FEI proposes to implement common rates effective January 1, 2023, FEI is also applying for approval of 2022 delivery rates for FEFN on a standalone basis. Based on the forecasts provided in Section 8 of the Application, FEI requests approval of an effective delivery rate increase of 3.41 percent for FEFN effective January 1, 2022.

Appendix A

FORECASTING

Appendix A1

CBOC REPORT

Table A1-1: Conference Board of Canada Report

BRITISH COLUMBIA	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Housing Starts, Singles, British Columbia (Thousands ('000s))	11,163	8,792	8,519	6,823	6,099	5,704
Forecast Percent Change		**-21.2%**	**-3.1%**	**-19.9%**	**-10.6%**	**-6.5%**
Housing Starts, Multiples, British Columbia (Thousands ('000s))	29,694	36,140	29,215	25,565	25,466	24,959
Forecast Percent Change		**21.7%**	**-19.2%**	**-12.5%**	**-0.4%**	**-2.0%**
Total	40,857	44,932	37,734	32,388	31,566	30,663

The Conference Board of Canada
Provincial Outlook Long-Term Economic Forecast 2021
April 29th, 2021

Appendix A2

HISTORICAL FORECAST AND CONSOLIDATED TABLES

ALSO REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Appendix A-2

Historical Forecast and Consolidated Tables

August 12, 2021

1. INTRODUCTION

This appendix presents two data sets as follows:

1. Historical and Forecast Data
    a. 2011-2020 actual data
    b. 2021 seed year data
    c. 2022 and 2023 forecast data
2. Percent Error
    a. 2011-2020 forecast, actual and percent error

2. HISTORICAL AND FORECAST DATA TABLES

Table A2-1: FEFN Historic Customer Counts, Customer Additions, Use per Customer and Energy

FORT NELSON	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Customers										
Rate Schedule 1	1,955	1,947	1,959	1,962	1,963	1,945	1,927	1,919	1,898	1,880
Rate Schedule 2.1	447	443	446	446	474	478	476	473		
Rate Schedule 2									460	452
Rate Schedule 2.2	31	31	31	31	7	7	6	4		
Rate Schedule 3									14	17
Rate Schedule 25	2	2	2	2	2	2	1	1	1	-
Total Customer	2,435	2,423	2,438	2,441	2,446	2,432	2,410	2,397	2,373	2,349
Customer Additions										
Rate Schedule 1	18	8	12	3	1	(18)	(18)	(8)	(21)	(18)
Rate Schedule 2.1	26	4	3	-	28	4	(2)	(3)		
Rate Schedule 2									3	(8)
Rate Schedule 2.2	3	-	-	-	(24)	-	(1)	(2)		
Rate Schedule 3									(6)	2
Rate Schedule 25			-	-	-	-	(1)	-	-	(1)
Total Customer Additions	47	12	15	3	5	(14)	(22)	(13)	(24)	(25)
UPC										
Rate Schedule 1	137.8	138.8	138.6	136.5	135.5	134.2	129.9	127.6	128.1	128.9
Rate Schedule 2.1	475.6	465.0	460.2	455.5	482.0	465.8	447.8	434.8		
Rate Schedule 2									402.2	382.6
Rate Schedule 2.2	3,325.7	3,227.9	3,555.2	3,425.0	6,616.0	7,868.6	8,085.8	9,169.2		
Rate Schedule 3									4,910.0	4,643.2
Demand Tjs										
Rate Schedule 1	268	269	270	268	265	262	251	245	244	243
Rate Schedule 2.1	206	205	204	204	223	222	214	206		
Rate Schedule 2									185	174
Rate Schedule 2.2	97	100	110	106	65	55	48	42	-	-
Rate Schedule 3									70	71
Rate Schedule 25	51	56	61	68	50	41	42	43	37	30
Total Demand	622	630	645	645	603	580	556	537	537	518

With the approval of FEI's 2016 RDA for FEFN, commencing in 2019, FEFN's commercial customers are taking service under Rate Schedules 2 and 3 (previously named Rates 2.1 and 2.2) with a separation point of 2,000 GJ per year (rather than the previous 6,000 GJ per year). FEI's forecast methods require historical demand, including the 2018 seed year, to be based on the same rate schedules as the forecast years. Therefore, in order to develop the commercial forecast for 2019 and 2020, FEI mapped the commercial customers to the new Rate Schedules 2 and 3 for the period from 2014 to 2017 using their average annual weather normalized consumption of those years. Customers with an average annual consumption of 2,000 GJs or less were mapped to Rate Schedule 2 while customers with an average annual consumption greater than 2,000 GJs were mapped to Rate Schedule 3. Table A2-2 below shows the Customer Count, Customer Additions, Use per Customer and Total Energy Demand in the previous Rate 2.1 and 2.2 commercial classes from 2011 to 2018 and the respective mapped numbers in the new Rate Schedules 2 and 3 commercial classes over the same period.

Additionally, and as discussed in Section 4.3.2.1, the final remaining RS 25 industrial customer switched to a bundled natural gas service under RS 3. In order to properly forecast RS 3 demand, FEI has mapped this customer to RS 3.

Table A2-2: FEFN Forecast Customer Counts, Customer Additions, Use per Customer and Energy

FORT NELSON	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021S	2022F	2023F
Customers													
Rate Schedule 1	1,955	1,947	1,959	1,962	1,963	1,945	1,927	1,919	1,898	1,880	1,866	1,853	1,841
Rate Schedule 2*	458	454	457	457	461	465	462	457	460	452	449	445	442
Rate Schedule 3*	22	22	22	22	22	22	21	21	15	16	15	13	12
Total Customer	2,435	2,423	2,438	2,441	2,446	2,432	2,410	2,397	2,373	2,348	2,329	2,311	2,295
Customer Additions													
Rate Schedule 1	18	8	12	3	1	(18)	(18)	(8)	(21)	(18)	(14)	(13)	(12)
Rate Schedule 2*	28	4	3	-	4	4	(3)	(5)	3	(8)	(3)	(3)	(3)
Rate Schedule 3*	1	-	-	-	-	-	(1)	-	(6)	1	(1)	(1)	(1)
Total Customer Additions	47	12	15	3	5	(14)	(22)	(13)	(24)	(25)	(19)	(18)	(16)
UPC													
Rate Schedule 1	137.8	138.8	138.6	136.5	135.5	134.2	129.9	127.6	128.1	128.9	127.2	125.8	124.4
Rate Schedule 2*	489.5	488.1	476.3	467.4	424.5	406.7	393.3	374.3	402.6	384.6	350.8	336.9	323.1
Rate Schedule 3*	5,905.2	6,332.3	7,154.1	7,439.1	6,442.1	6,133.7	5,842.9	5,716.1	7,168.3	6,303.8	6,393.9	6,377.9	6,361.9
Demand Tjs													
Rate Schedule 1	268	269	270	268	265	262	251	245	244	243	238	234	230
Rate Schedule 2*	224	222	218	214	196	189	182	171	185	174	157	150	143
Rate Schedule 3*	130	139	157	164	142	129	123	120	108	101	96	87	78
Total Demand	622	630	645	645	603	580	556	537	537	518	491	471	451

*2011-2018 Data mapped for forecasting purposes only

3. PERCENT ERROR DATA TABLES

In the data tables presented below, FEFN provides 10 years of historical demand, forecast demand and percent error for each customer class for total demand, customers, customer additions and use per customer (UPC). Percent error is the difference between the actual demand and the forecast demand, divided by the actual demand in a given year, or stated as a formula:

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

Table A2-3: FEFN Demand Variances

Demand

Rate Schedule 1 - Residential	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forecast	258,951	273,297	274,309	270,571	268,635	267,546	261,825	259,874	244,160	236,900
Actual	267,722	269,235	270,062	267,589	265,419	262,275	251,350	245,434	244,434	243,175
Error = (ACT-FCST)	8,771	(4,063)	(4,247)	(2,982)	(3,216)	(5,271)	(10,475)	(14,440)	274	6,275
Percent Error = (Error/ACT)	3.3%	-1.5%	-1.6%	-1.1%	-1.2%	-2.0%	-4.2%	-5.9%	0.1%	2.6%

Rate Schedule 2.1/2- Small Commercial	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forecast Rate Schedule 2.1	182,772	203,246	207,927	208,999	208,315	208,642	211,897	203,742		
Forecast Rate Schedule 2									160,160	150,377
Actual Rate Schedule 2.1	205,891	205,024	204,488	203,517	222,697	221,733	214,211	205,955		
Actual Rate Schedule 2									185,202	173,841
Error = (ACT-FCST)	23,119	1,778	(3,440)	(5,482)	14,382	13,091	2,314	2,213	25,042	23,464
Percent Error = (Error/ACT)	11.2%	0.9%	-1.7%	-2.7%	6.5%	5.9%	1.1%	1.1%	13.5%	13.5%

Rate Schedule 2.2/3 - Small Commercial	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forecast Rate Schedule 2.2	94,774	101,063	104,320	109,660	115,656	120,843	56,570	56,722		
Forecast Rate Schedule 3									61,061	53,232
Actual Rate Schedule 2.2	96,842	100,065	109,821	106,168	64,924	55,081	48,357	41,919		
Actual Rate Schedule 3									70,419	71,320
Error = (ACT-FCST)	2,068	(998)	5,502	(3,492)	(50,732)	(65,762)	(8,213)	(14,804)	9,358	18,088
Percent Error = (Error/ACT)	2.1%	-1.0%	5.0%	-3.3%	-78.1%	-119.4%	-17.0%	-35.3%	13.3%	25.4%

Commercial	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forecast	277,547	304,309	312,247	318,658	323,972	329,485	268,467	260,464		
Forecast									221,221	203,609
Actual	302,734	305,089	314,309	309,685	287,621	276,814	262,568	247,874		
Actual									255,621	245,161
Error = (ACT-FCST)	25,187	780	2,062	(8,973)	(36,351)	(52,672)	(5,899)	(12,591)	34,400	41,552
Percent Error = (Error/ACT)	8.3%	0.3%	0.7%	-2.9%	-12.6%	-19.0%	-2.2%	-5.1%	13.5%	16.9%

Rate Schedule 25* - General Firm Transportation	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forecast	58,492	54,995	54,995	67,084	55,832	55,832	39,685	39,684	41,500	41,500
Actual	51,354	55,832	60,756	67,598	49,790	41,110	41,847	43,197	37,105	29,541
Error = (ACT-FCST)	(7,138)	837	5,761	515	(6,042)	(14,722)	2,162	3,513	(4,395)	(11,959)
Percent Error = (Error/ACT)	-13.9%	1.5%	9.5%	0.8%	-12.1%	-35.8%	5.2%	8.1%	-11.8%	-40.5%

Note: Single remaining customer switched to RS 3 in 2020

Total Demand	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forecast	594,989	632,602	641,551	656,313	648,439	652,863	569,978	560,023	506,881	482,009
Actual	621,809	630,155	645,127	644,872	602,830	580,199	555,765	536,505	537,160	517,877
Error = (ACT-FCST)	26,820	(2,447)	3,576	(11,441)	(45,609)	(72,664)	(14,212)	(23,517)	30,279	35,868
Percent Error = (Error/ACT)	4.3%	-0.4%	0.6%	-1.8%	-7.6%	-12.5%	-2.6%	-4.4%	5.6%	6.9%

Table A2-4: FEFN UPC Variances

Rate Schedule 1 - Residential	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Forecast	133	140	140	138	136	135	133	132	125	123
Actual	138	139	139	137	136	134	130	128	128	129
Error = (ACT-FCST)	5	(1)	(1)	(1)	(1)	(1)	(3)	(5)	3	6
Percent Error = (Error/ACT)	3.5%	-1.1%	-1.0%	-0.8%	-0.5%	-0.4%	-2.6%	-3.7%	2.2%	4.6%

Rate Schedule 2.1/2 - Small Commercial	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Forecast Rate Schedule 2.1	435	466	465	463	453	443	444	425		
Forecast Rate Schedule 2									349	323
Actual Rate Schedule 2.1	476	465	460	456	482	466	448	435		
Actual Rate Schedule 2									402	383
Error = (ACT-FCST)	41	(1)	(5)	(7)	29	23	4	9	53	60
Percent Error = (Error/ACT)	8.6%	-0.3%	-1.1%	-1.6%	6.1%	4.9%	0.8%	2.2%	13.2%	15.7%

Rate Schedule 2.2/3 - Small Commercial	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Forecast Rate Schedule 2.2	3,385	3,609	3,726	3,487	3,535	3,584	8,081	8,103		
Forecast Rate Schedule 3									3,164	2,802
Actual Rate Schedule 2.2	3,326	3,228	3,555	3,425	6,616	7,869	8,086	9,169		
Actual Rate Schedule 3									4,910	4,643
Error = (ACT-FCST)	(59)	(381)	(171)	(62)	3,081	4,285	4	1,066	1,746	1,842
Percent Error = (Error/ACT)	-1.8%	-11.8%	-4.8%	-1.8%	46.6%	54.5%	0.1%	11.6%	35.6%	39.7%

Table A2-5: FEFN Customer Variances

Rate Schedule 1 - Residential	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Forecast	1,955	1,960	1,973	1,971	1,984	1,997	1,965	1,966	1,941	1,918
Actual	1,955	1,947	1,959	1,962	1,963	1,945	1,927	1,919	1,898	1,880
Error = (ACT-FCST)	0	(13)	(14)	(9)	(21)	(52)	(38)	(47)	(43)	(38)
Percent Error = (Error/ACT)	0.0%	-0.7%	-0.7%	-0.5%	-1.1%	-2.7%	-2.0%	-2.4%	-2.3%	-2.0%

Rate Schedule 2 - Small Commercial	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Forecast Rate Schedule 2.1	422	443	454	457	468	479	478	480		
Forecast Rate Schedule 2									465	468
Actual Rate Schedule 2.1	447	443	446	446	474	478	476	473		
Actual Rate Schedule 2									460	452
Error = (ACT-FCST)	25	-	(8)	(11)	6	(1)	(2)	(7)	(5)	(16)
Percent Error = (Error/ACT)	5.6%	0.0%	-1.8%	-2.5%	1.3%	-0.2%	-0.4%	-1.5%	-1.1%	-3.5%

Rate Schedule 3- Small Commercial	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Forecast Rate Schedule 2.2	28	28	28	32	33	34	7	7		
Forecast Rate Schedule 3									19	19
Actual Rate Schedule 2.2	31	31	31	31	7	7	6	4		
Actual Rate Schedule 3									14	17
Error = (ACT-FCST)	-	-	-	-	-	-	-	-	(5)	(2)
Percent Error = (Error/ACT)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-35.7%	-11.8%

Table A2-6: FEFN Customer Additions Variances

Rate Schedule 1 - Residential	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forecast	10	11	13	12	13	13	1	1	32	(23)
Actual	18	8	12	3	1	(18)	(18)	(8)	(21)	(18)
Error = (ACT-FCST)	8	(3)	(1)	(9)	(12)	(31)	(19)	(9)	(53)	5
Percent Error = (Error/ACT)	44.4%	-37.5%	-8.3%	-300.0%	-1200.0%	172.2%	105.6%	112.5%	252.4%	-27.8%

Rate Schedule 2.1/2 - Small Commercial	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forecast Rate Schedule 2.1	2	11	11	11	11	11	2	2		
Forecast Rate Schedule 2									9	3
Actual Rate Schedule 2.1	26	4	3	-	28	4	(2)	(3)		
Actual Rate Schedule 2									3	(8)
Error = (ACT-FCST)	24	(7)	(8)	(11)	17	(7)	(4)	(5)	(6)	(11)
Percent Error = (Error/ACT)	92.3%	-175.0%	-266.7%		60.7%	-175.0%	200.0%	166.7%	-200.0%	137.5%

Rate Schedule 2.2/3 - Large Commercial	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forecast Rate Schedule 2.2	-	-	-	1	1	1	-	-		
Forecast Rate Schedule 3									(1)	-
Actual Rate Schedule 2.2	3	-	-	-	(24)	-	(1)	(2)		
Actual Rate Schedule 3									(6)	3
Error = (ACT-FCST)	3	-	-	(1)	(25)	(1)	(1)	(2)	(5)	3
Percent Error = (Error/ACT)					104.2%		100.0%	100.0%	83.3%	100.0%

Appendix A3

DEMAND FORECAST METHOD

Appendix A3

Demand Forecast Method

August 12, 2021

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List of Tables and Figures

1. INTRODUCTION

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

The following table shows the high level method used for each component of FEI's demand forecast.

Table A3-1: Summary of FEI Forecast Methods

Rate Group	Customer Additions	Customers	Use Rate	Demand
Residential	CBOC forecast by dwelling type	Prior year customers + customer adds	Exponential Smoothing method, using normalized historical UPC	Product of Customers and Use Rates
Commercial	3 Yr. Avg. historical additions	Prior year customers + customer adds	Exponential Smoothing method, using normalized historical UPC	Product of Customers and Use Rates

FEI's demand forecast methods are consistent with the recommendations in the FEI Forecasting Method Study filed as Appendix B2 in FortisBC's 2020-2024 MRP Application. The Forecasting Method Study represented the culmination of a number of years of research and testing of alternative forecasting methods in response to the forecasting directives in Order G-86-15 and accompanying decision related to the FEI Annual Review for 2015 Rates Application. As a result of this study, FEI adopted the Exponential Smoothing method (ETS) for the purpose of forecasting residential and commercial use rates, as ETS proved to be the most accurate method for this purpose.

In the following sections, FEI provides background information, including a description of FEI's regions and rate classes, the time periods used in the forecast, and the weather normalization process, and then describes each of FEI's forecast methods used to derive the 2022 demand forecast, in the following order:

- Residential Customer Additions;
- Commercial Customer Additions;
- Residential and Commercial Use Rates; and
- Residential and Commercial Demand Forecast.

2. BACKGROUND INFORMATION

2.1 ACTUAL, PROJECTED AND FORECAST YEARS

FEI's demand forecasts contain data from three time frames:

- **Actual Years:** Actual years are those for which actual data exists for the full calendar year.
- **Forecast Year(s)**: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or two or more years depending on the filing.
- **Seed Year:** The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2021 and the Seed Year forecast is based on the latest actual years, including 2020.

2.2 RATE CLASSES

The following residential, commercial and industrial rate classes are included in the annual demand forecast:

Table A3-2: Rate Classes

Residential	
Rate Schedule 1 - Residential	This rate schedule is applicable to firm gas supplied at one premise for use in approved appliances for all residential applications in single-family residences, separately metered single family townhouses, row houses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments.
Commercial	
Rate Schedule 2 - Small Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of less than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 3 - Large Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of greater than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.

2.3 WEATHER NORMALIZATION OF RESIDENTIAL AND COMMERCIAL USE RATES

Residential and commercial rate schedules (Rate Schedules (RS) 1, RS 2 and RS 3) are weather sensitive. A weather normalization process is applied to all actual use rates for these rate schedules as described in this section. Separate normalization factors are developed for each rate schedule and month.

Actual UPC is weather normalized on a monthly basis for each rate class by dividing the actual UPC by a normalization factor. The normalization factor is derived from a non-linear regression model that estimates the impact of the monthly weather variation on the load. As the relationship between weather and the usage is not linear, FEI considers three non-linear models that are often used when modeling weather impact. One is based on the Gompertz distribution (the "Gompertz" model). The other two methods are variants based on the logit formulation with one (Logit-4) allowing for an additional parameter for optimal fitting. The models are:

- Gompertz

$$Estimated\ Monthly\ UPC = A \times e^{\left(-e^{-B \times (Avg.Monthly\ Temp. - C)}\right)}$$

- Logit-3

$$Estimated\ Monthly\ UPC = \frac{A}{1 + B \times e^{(-C \times Temp)}}$$

- Logit-4

$$Estimated\ Monthly\ UPC = \frac{(D + (A - D))}{1 + B \times e^{(-C \times Temp)}}$$

The A/B/C/D parameters are estimated through a least squares method to minimize the sum of squared error (SSE). The optimization process to minimize the SSE is done using the Solver tool in Microsoft Excel.

The three non-linear models were tested to see which provided the best fit for each rate class. The heat sensitivity estimated from the model assumes that the sensitivity varies not only depending on the weather but also on the rate class. For example, the residential rate schedule shows higher sensitivity to weather compared to the commercial rate schedules, and FEI's normalization factors account for the difference.

3. RESIDENTIAL CUSTOMER ADDITIONS

The residential net customer additions forecast was developed based on housing starts data from CBOC forecast of April 29, 2021, Provincial Outlook Long-Term Economic Forecast 2021. The housing starts data from that forecast follows:

Table A3-3: BC Housing Starts Data

Housing Type	2019	2020	2021	2022
Housing Starts, Singles, British Columbia	8,792	8,519	6,823	6,099
Housing Starts, Multiples, British Columbia	36,140	29,215	25,565	25,466
Total	44,932	37,734	32,388	31,566

From the above housing starts forecast, the 2022 SFD growth rate is calculated as follows:

$$2022\ SFD\ Growth\ Rate = \left(\frac{6{,}099}{6{,}823}\right) - 1 = -10.6\%$$

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

Table A3-4: Growth Rates

Housing Type	2021	2022
SFD Forecast Percent Change	**-19.9%**	**-10.6%**
MFD Forecast Percent Change	**-12.5%**	**-0.4%**

The following table incorporates the FEFN proportions of the actual account additions by single family dwelling (SFD) and multi-family (MFD) based on historical percentages from internal data in columns A and B. The 2020 actual total additions are shown in column C, followed by the SFD and MFD proportions in columns D and E. Finally the CBOC growth rates for 2021 are applied to the SFD and MFD proportions for 2021 in column F and G and for 2022 in column I and J.

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

	Internal Split		Actual Adds 2020			2021S			2022F		
Sub-Region	SFD	MFD	Total	SFD	MFD	SFD	MFD	Total	SFD	MFD	Total
	A	B	C	D	E	F	G	H	I	J	K
Fort Nelson	100%	0%	(18)	(18)	-	(14)	-	(14)	(13)	-	(13)

For example, the Fort Nelson 2022F SFD value of -13 (column I) is derived as follows:

- Fort Neslon 2020 Internal Split – SFD percentage = 100% (column A);
- Fort Neson 2020 Actual additions = -18 (column C)

$$FTN\ 2020Actual\ SFD = 100\%\ \times -18 = -18\ (column\ D)$$

$$FTN\ 2021\ Seed\ SFD = (1 - 19.9\%) \times -18 = -14\ (column\ F)$$

$$FTN\ 2022\ Forecast\ SFD = (1 - 10.6\%) \times -14 = -13(column\ I)$$

4. COMMERCIAL CUSTOMER ADDITIONS

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

The following table shows the customer additions for Fort Nelson RS 2.

Table A3-6: Customer Additions for Fort Nelson RS 2

Year	Customers Rate Schedule 2	Customer Additions	Average 2018-2020
2017	462.000		
2018	457.000	(5)	
2019	460.000	3	
2020	452.000	(8)	(3.333)
2021S	448.667		
2022F	445.333		

The three-year average additions are -3.333, so net additions forecast for 2021 are 448.667 and 445.333 customers for 2022 .

$$2021S\ Customers = 2020\ Customers\ + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2021S = 449 = 452 + (3)$$

5. RESIDENTIAL AND COMMERCIAL USE RATES

5.1 *THE EXPONENTIAL SMOOTHING METHOD*

FEI develops its use rate forecasts based on ten years of annual use rates by region and rate class. The UPC values are weather-normalized using the process set out in section 2 above.

The ten years of data is used to calculate the UPC forecast using ETS, as implemented in Microsoft Excel.

ETS is implemented as both a formula and "wizard" in Excel 2016. Intermediate calculations and steps are not exposed or reproducible. Microsoft has not published, and is unlikely to publish, the specific algorithms and procedures used in its software.

The UPC method for Lower Mainland Rate Schedule 1 is demonstrated below. All other use rate forecasts are developed using the same method.

5.1.1 Fort Nelson Rate Schedule 1 UPC Example

The forecast UPCs for Fort Nelson Rate Schedule 1 were calculated as follows:

Start with ten years of weather normalized annual UPCs:

Fort Nelson UPC		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1		137.8	138.8	138.6	136.5	135.5	134.2	129.9	127.6	128.1	128.9

In Excel, the new "forecast.ets()" function is used to calculate the 2020 and 2021 forecasts.

Fort Nelson UPC	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021S	2022F
Rate Schedule 1	137.8	138.8	138.6	136.5	135.5	134.2	129.9	127.6	128.1	128.9	=FORECAST.ETS(M2,$C$8:$L$8,$C$2:$L$2,0,0)	
											FORECAST.ETS(target_date, values, timeline, [seasonality], [data_completion], [aggregation])	

The resulting forecasts for 2021 and 2022 are shown:

Fort Nelson UPC	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1	137.8	138.8	138.6	136.5	135.5	134.2	129.9	127.6	128.1	128.9	127.2	125.8

These annual UPCs must be converted to monthly values for input into FIS and this is accomplished by considering actual monthly proportions from the past three years.

Fort Nelson													
UPC Rs1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2018	21.8	17.2	15.3	8.4	5.2	3.1	1.9	2.3	4.1	9.8	17.5	20.9	127.6
2019	21.4	17.5	16.0	8.5	4.8	2.4	1.6	2.2	4.4	10.2	17.5	21.8	128.1
2020	22.1	17.7	13.9	9.4	5.6	2.5	1.9	2.2	4.7	9.6	18.0	21.3	128.9
UPC Rs1													
2018	17%	14%	12%	7%	4%	2%	2%	2%	3%	8%	14%	16%	100%
2019	17%	14%	12%	7%	4%	2%	1%	2%	3%	8%	14%	17%	100%
2020	17%	14%	11%	7%	4%	2%	2%	2%	4%	7%	14%	17%	101%
3 yr avg	17%	14%	12%	7%	4%	2%	1%	2%	3%	8%	14%	17%	100%

In the preceeding table the first three rows show the actual weather normalized monthly UPC values. The second three rows show the proportions for each year along with the average proportion in the final row.

The average monthly proportion is applied to the annual ETS forecast to establish the monthly forecast, as follows:

FTN Rs1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2021S UPC Forecast	21.6	17.3	15.0	8.7	5.1	2.6	1.8	2.2	4.4	9.8	17.5	21.2	127.2
2022F UPC Forecast	21.4	17.2	14.8	8.6	5.1	2.6	1.8	2.2	4.3	9.7	17.3	21.0	125.8

Note that the totals of 127.2 and 125.8 match the 2021S and 2022F ETS forecasts, respectively.

Identical calculations are completed for all rate classes. The resulting monthly values are entered into FIS.

6. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

The residential and commercial demand forecasts are the products of the monthly customer forecast and the corresponding monthly use rates forecast. The forecasts are then summed to arrive at the amalgamated demand forecast.

7. SUMMARY OF DEMAND FORECAST

Once the customer additions and use rate forecasts have been completed, they are entered into FIS. FIS then aggregates the demand by month and rate class to prepare the overall forecast of demand.

Appendix B

CALCULATION OF FEFN'S MIDSTREAM RATES AT 5 PERCENT OF FEI

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND, AND FORT NELSON SERVICE AREAS
STORAGE AND TRANSPORT RELATED CHARGES FLOW-THROUGH BY RATE SCHEDULE FOR THE FORECAST PERIOD JAN TO DEC 2022
FIVE-DAY AVERAGE FORWARD PRICES - MAY 17, 18, 19, 20, AND 21, 2021
FEFN COMMON COMMODITY RATES AND 5% FEI STORAGE AND TRANSPORT RECOVERY CHARGES

Line	Particulars	Unit	Residential RS-1	Commercial RS-2	Commercial RS-3	General Firm RS-5	NGV RS-6	Total MCRA Gas Costs	For Information Only: Fort Nelson (FEFN) RS-1	RS-2	RS-3	RS-5	RS-6	Total	Term & Spot Gas Sales RS-14A	Off-System Interruptible Sales RS-30
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	**MCRA Sales Quantity** (Natural Gas & Propane)	TJ	79,606.2	29,265.2	27,123.2	16,127.9 [g]	23.3	*152,145.8*	223.2	170.3	59.5	-	-	453.1	-	28,629.8
2																
3	**Load Factor Adjusted Quantity**															
4	Load Factor [a]	%	31.0%	30.5%	36.4%	50.4%	100.0%									
5	Load Factor Adjusted Quantity	TJ	257,040.0	96,054.8	74,417.0	31,997.0	23.3	*459,532.1*								
6	Load Factor Adjusted Volumetric Allocation	%	55.9%	20.9%	16.2%	7.0%	0.0%	100.0%								
7																
8	**MCRA Cost of Gas - Load Factor Adjusted Allocation**															
9	Midstream Commodity Related Costs (Net of Mitigation)	$000	**$ 5,551.7**	**$ 2,074.6**	**$ 1,607.3**	**$ 691.1**	**$ 0.5**	**$ 9,925.2**							**$ -**	**$ -**
10	Midstream Commodity (Natural Gas) Related Costs		49,687.1	18,567.9	14,385.2	6,185.2	4.5	88,829.8							-	75,870.5
11	Propane Costs to be Recovered via Midstream rates		1,227.5	458.7	355.4	152.8	0.1	2,194.6							-	-
12	Allocation of FEFN Costs to be Recovered via Midstream rates [b]		19.9	7.4	5.8	2.5	0.0	35.5								
13	Allocation of FEFN Storage and Transport recoveries [c]		(18.5)	(6.9)	(5.4)	(2.3)	(0.0)	(33.0)			Total FEFN Storage and Transport recoveries			$ (33.0)		
14	Midstream Commodity Related Mitigation		(45,364.4)	(16,952.5)	(13,133.7)	(5,647.1)	(4.1)	(81,101.7)			(Line 1 quantities x Line 46 rates)				-	(75,870.5)
15	Storage Related Costs (Net of Mitigation)	$000	**31,904.8**	**11,922.7**	**9,236.9**	**3,971.6**	**2.9**	**57,038.9**							**-**	**-**
16	Storage Related Costs		31,904.8	11,922.7	9,236.9	3,971.6	2.9	57,038.9							-	-
17	Storage Related Mitigation		-	-	-	-	-	-							-	-
18	Transportation Related Costs (Net of Mitigation)	$000	**76,969.3**	**28,763.1**	**22,283.8**	**9,581.3**	**7.0**	**137,604.6**							**-**	**-**
19	Transportation Related Costs		101,300.0	37,855.4	29,327.9	12,610.1	9.2	181,102.6							-	-
20	Transportation Related Mitigation		(24,330.7)	(9,092.3)	(7,044.1)	(3,028.7)	(2.2)	(43,498.0)							-	-
21	GSMIP Incentive Sharing	$000	**559.4**	**209.0**	**161.9**	**69.6**	**0.1**	**1,000.0**							**-**	**-**
22	Core Market Administration Costs - MCRA 70%	$000	**2,162.9**	**808.3**	**626.2**	**269.2**	**0.2**	**3,866.8**							**-**	**-**
23	**Total Midstream Cost of Gas Allocated by Rate Class**	$000	$ 117,148.1	$ 43,777.8	$ 33,916.2	$ 14,582.9	$ 10.6	**$ 209,435.5**							$ -	$ -
24	T-Service UAF to be recovered via delivery revenues [d]							1,048.7								
25	FEFN Midstream recoveries via FEFN Storage and Transport rates [c]							33.0								
26	**Total MCRA Gas Costs**							$ 210,517.2								
27																
28	1/2 of Pre-Tax Amort. MCRA Deficit/(Surplus) as of Jan 1, 2022 [e]	$000	$ (1,455.1)	$ (543.8)	$ (421.3)	$ (181.1)	$ (0.1)	$ (2,601.5)								
29	Allocation of FEFN Rider 6 recoveries [f]		0.3	0.1	0.1	0.0	0.0	0.5			Total FEFN Rider 6 recoveries			$ 0.5		
30	**Total Deferral Amortization to be Recovered via Rider 6**	$000	$ (1,454.9)	$ (543.7)	$ (421.2)	$ (181.1)	$ (0.1)	$ (2,601.0)			(Line 1 quantities x Line 50 rates)					
31																
32								**Average**								
33	**MCRA Cost of Gas Unitized**							**Costs**								
34	Midstream Commodity Related Costs (Net of Mitigation)	$/GJ	$ 0.0697	$ 0.0709	$ 0.0593	$ 0.0429	$ 0.0216	$ 0.0652								
35	Storage Related Costs (Net of Mitigation)	$/GJ	0.4008	0.4074	0.3406	0.2463	0.1241	0.3749								
36	Transportation Related Costs (Net of Mitigation)	$/GJ	0.9669	0.9828	0.8216	0.5941	0.2994	0.9044								
37	GSMIP Incentive Sharing	$/GJ	0.0070	0.0071	0.0060	0.0043	0.0022	0.0066								
38	Core Market Administration Costs - MCRA 70%	$/GJ	0.0272	0.0276	0.0231	0.0167	0.0084	0.0254								
39	**MCRA Flow-Through Costs before MCRA deferral amortization**	$/GJ	$ 1.4716	$ 1.4959	$ 1.2504	$ 0.9042	$ 0.4558	$ 1.3765								
40	**MCRA Deferral Amortization via Rate Rider 6**	$/GJ	$ (0.0183)	$ (0.0186)	$ (0.0155)	$ (0.0112)	$ (0.0057)	$ (0.0171)								
41																
42																
43	**TESTED January 1, 2022 Flow-through Storage and Transport Related Charges**					**RS4, RS7 & RS46**										
44			**RS-1**	**RS-2**	**RS-3**	**RS-5**	**RS-6**		**RS-1**	**RS-2**	**RS-3**	**RS-5**	**RS-6**			
45	**Storage and Transport Flow-Through**		**$ 1.472**	**$ 1.496**	**$ 1.250**	**$ 0.904**	**$ 0.456**		**$ 0.074**	**$ 0.075**	**$ 0.063**	**$ 0.045**	**$ 0.023**			
46	Existing Storage and Transport (effective Jan 1, 2021)		1.350	1.373	1.148	0.830	0.418									
47	Increase / (Decrease)	$/GJ	$ 0.122	$ 0.123	$ 0.102	$ 0.074	$ 0.038									
48	Increase / (Decrease)	%	9.04%	8.96%	8.89%	8.92%	9.09%									
49																
50	**MCRA Rate Rider 6 Flow-Through**		**$ (0.018)**	**$ (0.019)**	**$ (0.016)**	**$ (0.011)**	**$ (0.006)**		**$ (0.001)**	**$ (0.001)**	**$ (0.001)**	**$ (0.001)**	**$ -**			
51	Existing MCRA Rate Rider 6 (effective Jan 1, 2021)		0.047	0.047	0.040	0.029	0.014									
52	(Increase) / Decrease	$/GJ	$ (0.065)	$ (0.066)	$ (0.056)	$ (0.040)	$ (0.020)									
53	(Increase) / Decrease	%	138.30%	140.43%	140.00%	137.93%	142.86%									

Notes:
(a) Based on the historical 3-year (2017, 2018, and 2019 data) rolling average load factors for Rate Schedules 1, 2, 3 and 5.
(b) FEFN costs to be recovered via midstream rates are calculated net of the commodity cost recoveries at $2.844/GJ FEI Commodity Cost Recovery Charge.
(c) Allocation of the FEFN Storage and Transport recoveries as shown in Line 13, Col.13.
(d) The total cost of UAF (Sales Rate Classes and T-Service) is included as a component of gas purchased. Sales UAF costs are recovered via gas cost recovery rates.
As the T-Service UAF costs are recovered via delivery revenues, they are excluded from the storage and transportation flow-through calculation.
(e) January 1, 2022 MCRA forecast balance includes the December 31, 2021 FEFN GCRA projected closing balance of $85 thousand deficit as an opening balance adjustment; 1/2 of the January 1, 2022 MCRA forecast balance is used in setting Rate Rider 6.
(f) Allocation of the FEFN Rider 6 recoveries as shown in Line 29 Col.13.
(g) Storage & Transport and MCRA Rate Rider 6 charges for RS-4, RS-7, and RS-46 are set at the RS-5 tariff rates. For midstream cost allocation purposes the RS-5 allocations include RS-4, RS-7, and RS-46 forecast sales as well as the RS-5 forecast 1,701.5 TJ.
Slight differences in totals due to rounding.

Appendix C

STAKEHOLDER AND INDIGENOUS CONSULTATION

Appendix C-1

VIRTUAL TOWN HALL PRESENTATION

Fort Nelson Common Rates Application

Virtual information session

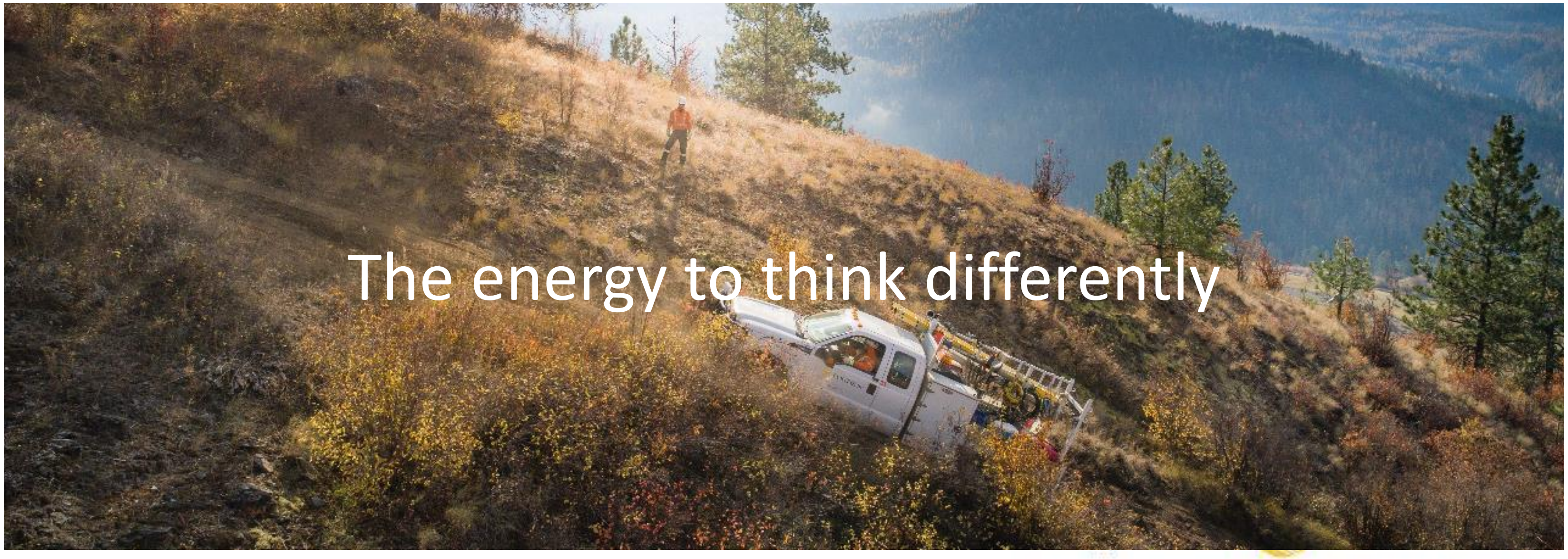
Tuesday, April 27, 2021

Agenda

- Introductions
- Who we are
- Common Rates Application overview
- Next Steps

Who is FortisBC?

FortisBC is an electricity, natural gas and renewable energy utility in the province of BC, a subsidiary of Newfoundland-based Fortis Inc., Canada's largest private utility company.



Who is FortisBC?

BC's largest energy provider

- more than 2,400 employees
- deliver natural gas, electricity, renewable natural gas and innovative energy solutions
- 1.2 million customers in 135 communities

Sustainability in all we do

Sustainability is not something we do. It’s how we do everything

Our sustainability framework:

- supporting our customers
- working with our partners and communities
- protecting the environment
- investing in our employees

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Energy at work FORTIS BC™

Common Rates Application for the Fort Nelson Service Area (FEFN)

History of FortisBC (FEI) Common Rates

1985	• Fort Nelson distribution acquired by Inland Gas
1989	• Amalgamation of Lower Mainland, Inland, Columbia and Fort Nelson
1990	• Revelstoke propane system – Common delivery rates with Inland
1993	• Common delivery rate for Lower Mainland, Inland, and Columbia (together Mainland)
2004	• Common cost of gas rates for Mainland
2007	• Amalgamation and common rates for Squamish and Mainland
2012	• Amalgamation of Mainland, Vancouver Island, and Whistler
2015	• Common Rates for Mainland, Vancouver Island, and Whistler (together FEI)
2020	• Common cost of gas rates for Revelstoke propane system

Fort Nelson is now the only service area with separate rates

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Why are we proposing common rates now?

BCUC Decision and Order G-48-19, page 11:

"Accordingly, the Panel directs FEI to include in the next RRA for FEFN, a discussion of the potential for postage stamping rates in FEFN along with the rest of FEI…"

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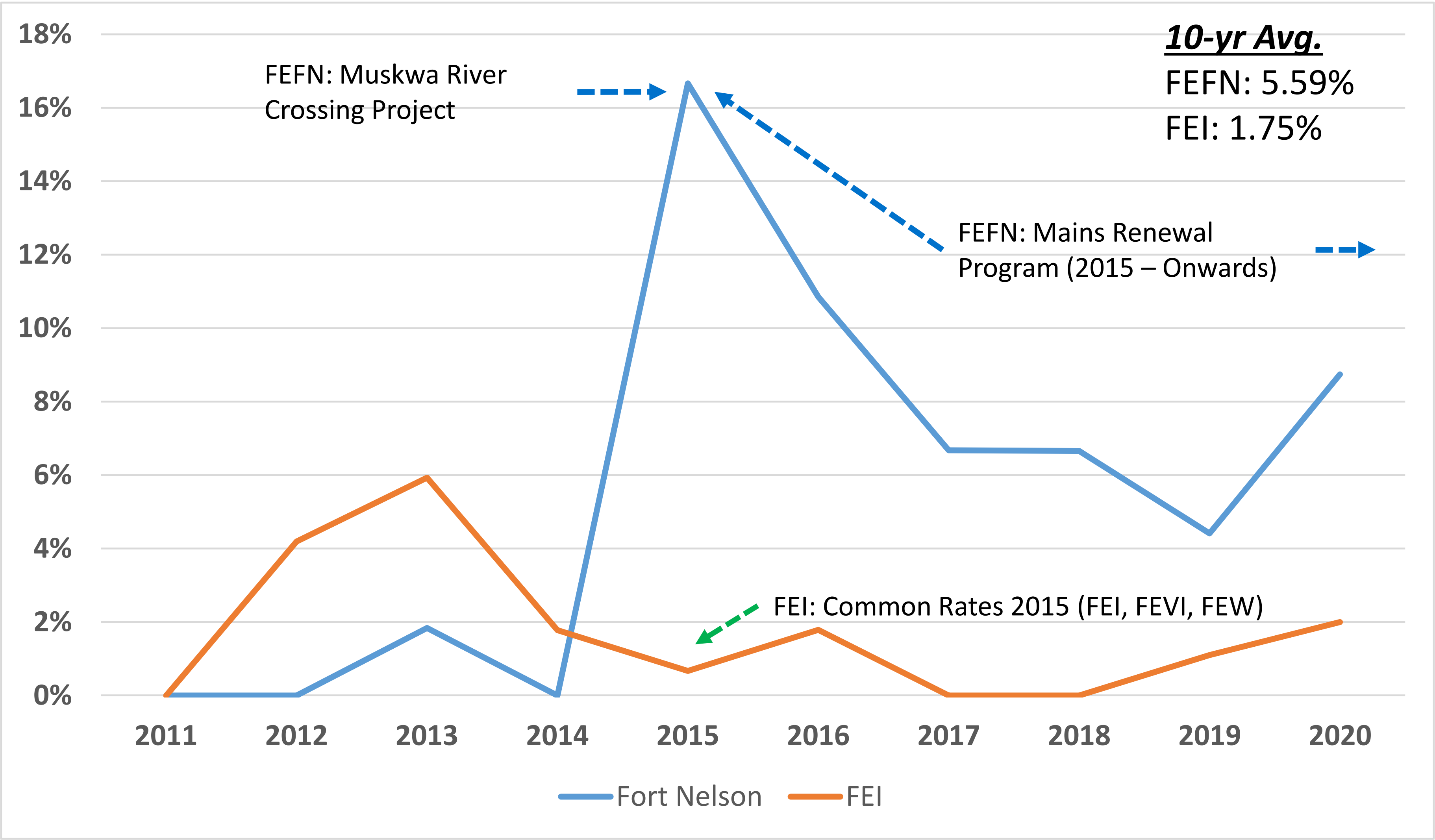
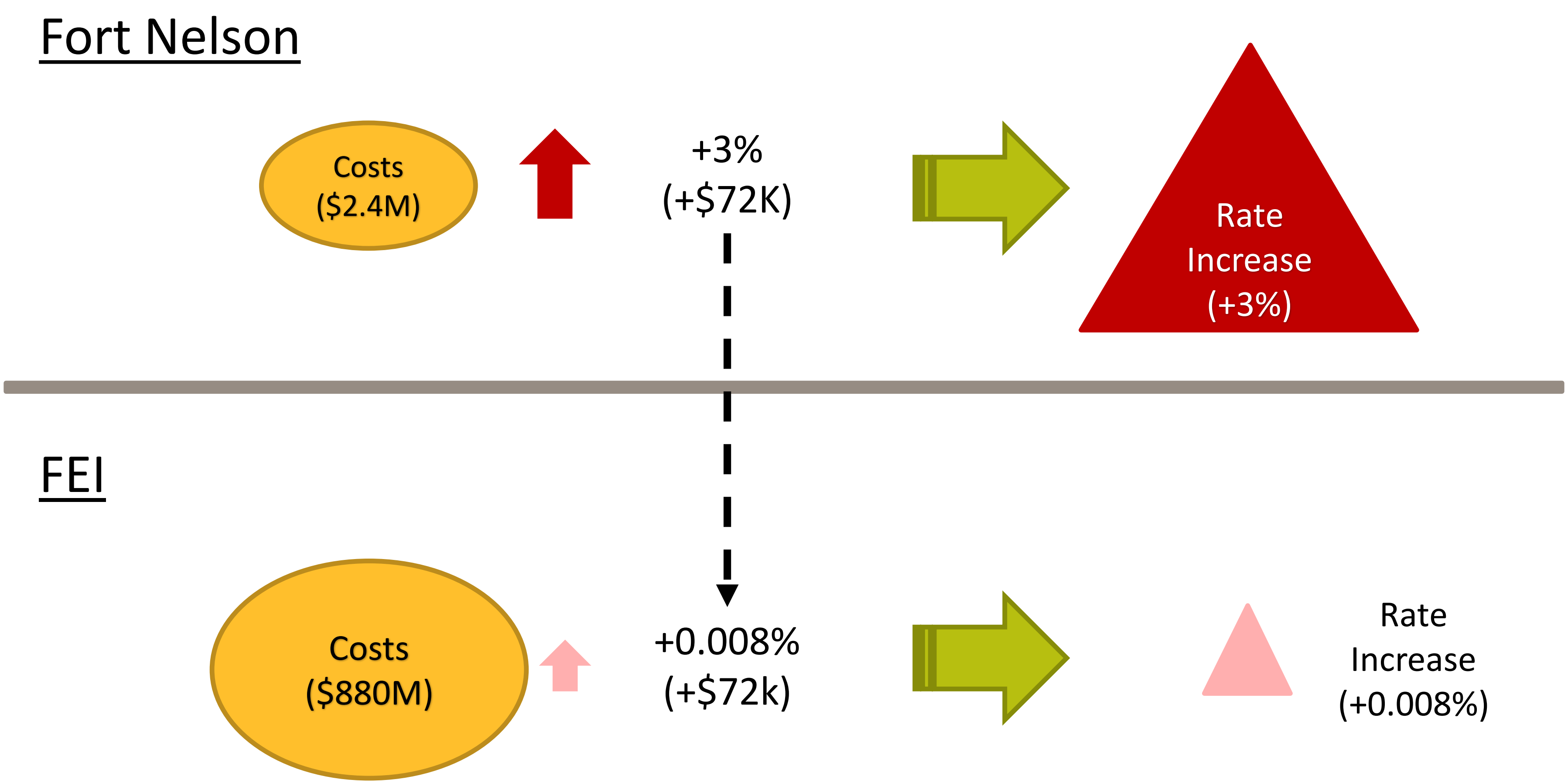
Benefits of Common Rates

- Rate stability over time for Fort Nelson customers
- A broader customer base to absorb localized infrastructure investments
- Limits the impact of changes in Fort Nelson customers' natural gas demand volume on rates

10-Year Delivery Rate Change (FEFN vs. FEI)



The Impact of Cost Increases on FEFN Delivery Rates Compared to FEI



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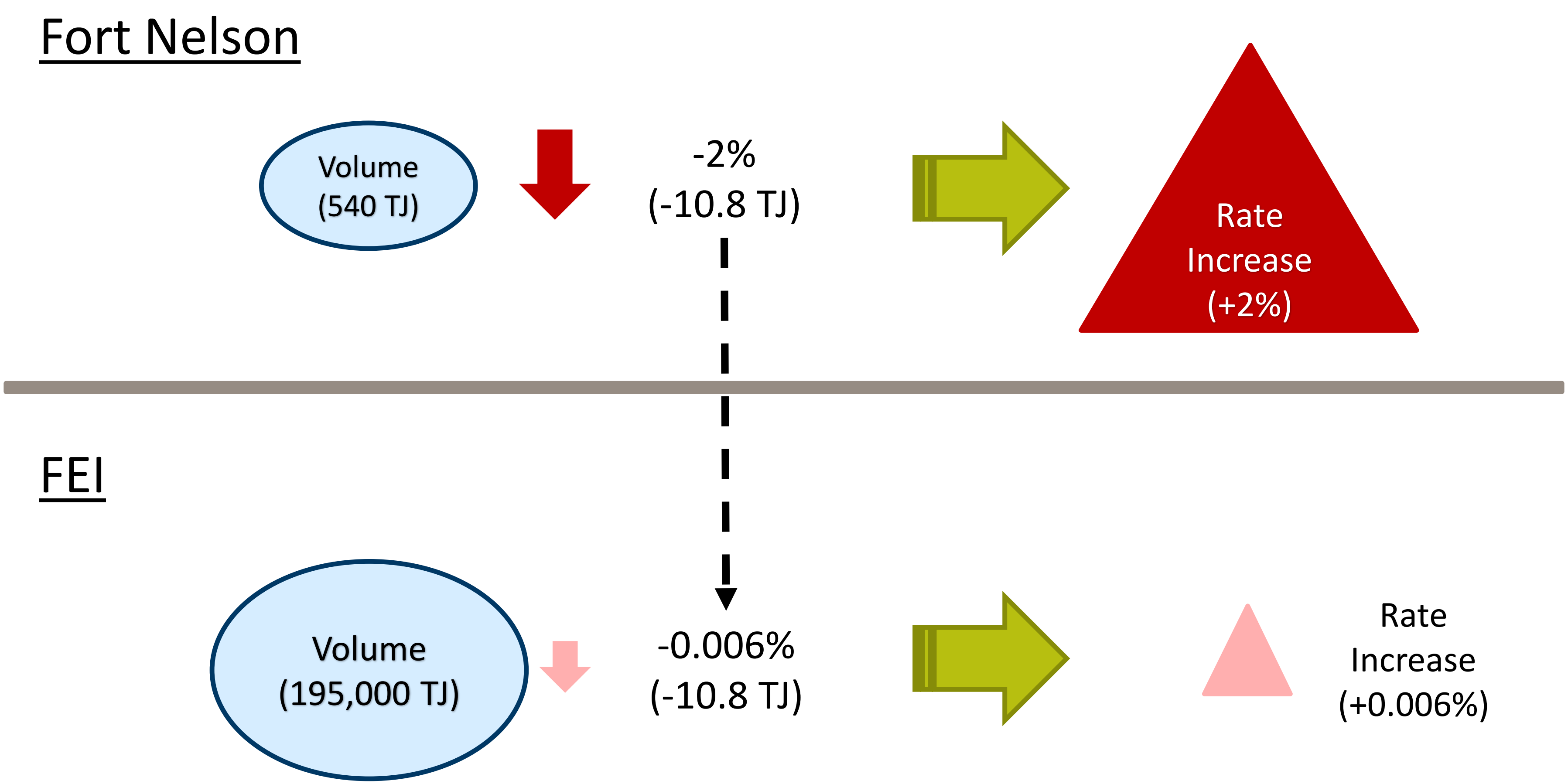
The Impact of Changes in Consumption on FEFN Delivery Rates Compared to FEI



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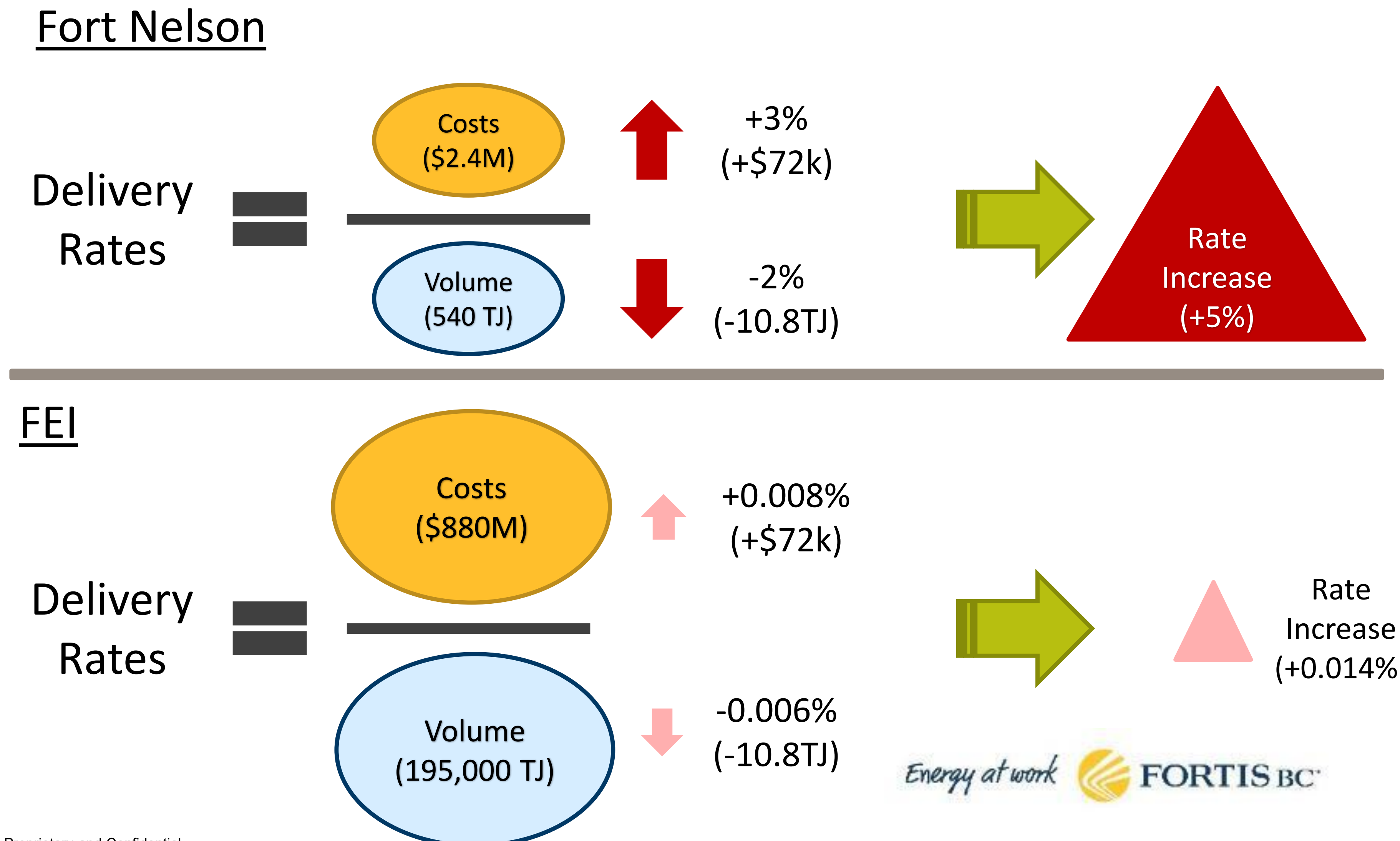
Summary of the Impact of Changes in Costs and Consumption on FEFN vs FEI



Overview of Common Rate Options for Fort Nelson

Components of Natural Gas Rates

Delivery

- Recovery for natural gas system and daily operations
- Includes variable and fixed costs
- The cost of *delivering* natural gas through FEI/FEFN's natural gas system to your home or business

Cost of Gas

- Part of the commodity related charges
- Market price of natural gas
- Flow-though (No mark up)

Storage and Transport

- Part of the commodity related charges
- 3rd party costs to store and transport natural gas to Fort Nelson distribution system
- Flow-though (No mark up)

Current (2021) Rates Comparison (FEFN vs. FEI)

Residential Customers (RS 1)

Components	FEFN	FEI
Delivery Margin Related Charges		
Basic Charge	$ 0.3701 / day	$ 0.4216 / day
Delivery Charge*	$ 4.118 / GJ	$ 4.915 / GJ
Commodity Related Charges		
Cost of Gas	$ 2.999 / GJ	$ 2.844 / GJ
Storage & Transport*	$ 0.043 / GJ	$ 1.397 / GJ

* Exclude Rate Riders

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Current (2021) Rates Comparison (FEFN vs. FEI)

Commercial Customers (RS 2 and RS 3)

Components	FEFN	FEI
Small Commercial RS 2 (< 2,000 GJ)		
Basic Charge	$ 1.2151 / day	$ 0.9616 / day
Delivery Charge*	$ 4.461 / GJ	$ 3.773 / GJ
Cost of Gas	$ 2.999 / GJ	$ 2.844 / GJ
Storage & Transport*	$ 0.043 / GJ	$ 1.373 / GJ
Large Commercial RS 3 (> 2,000 GJ)		
Basic Charge	$ 3.6845 / day	$ 4.8026 / day
Delivery Charge*	$ 3.839 / GJ	$ 3.279 / GJ
Cost of Gas	$ 2.999 / GJ	$ 2.844 / GJ
Storage & Transport*	$ 0.036 / GJ	$ 1.148 / GJ

* Exclude Rate Riders

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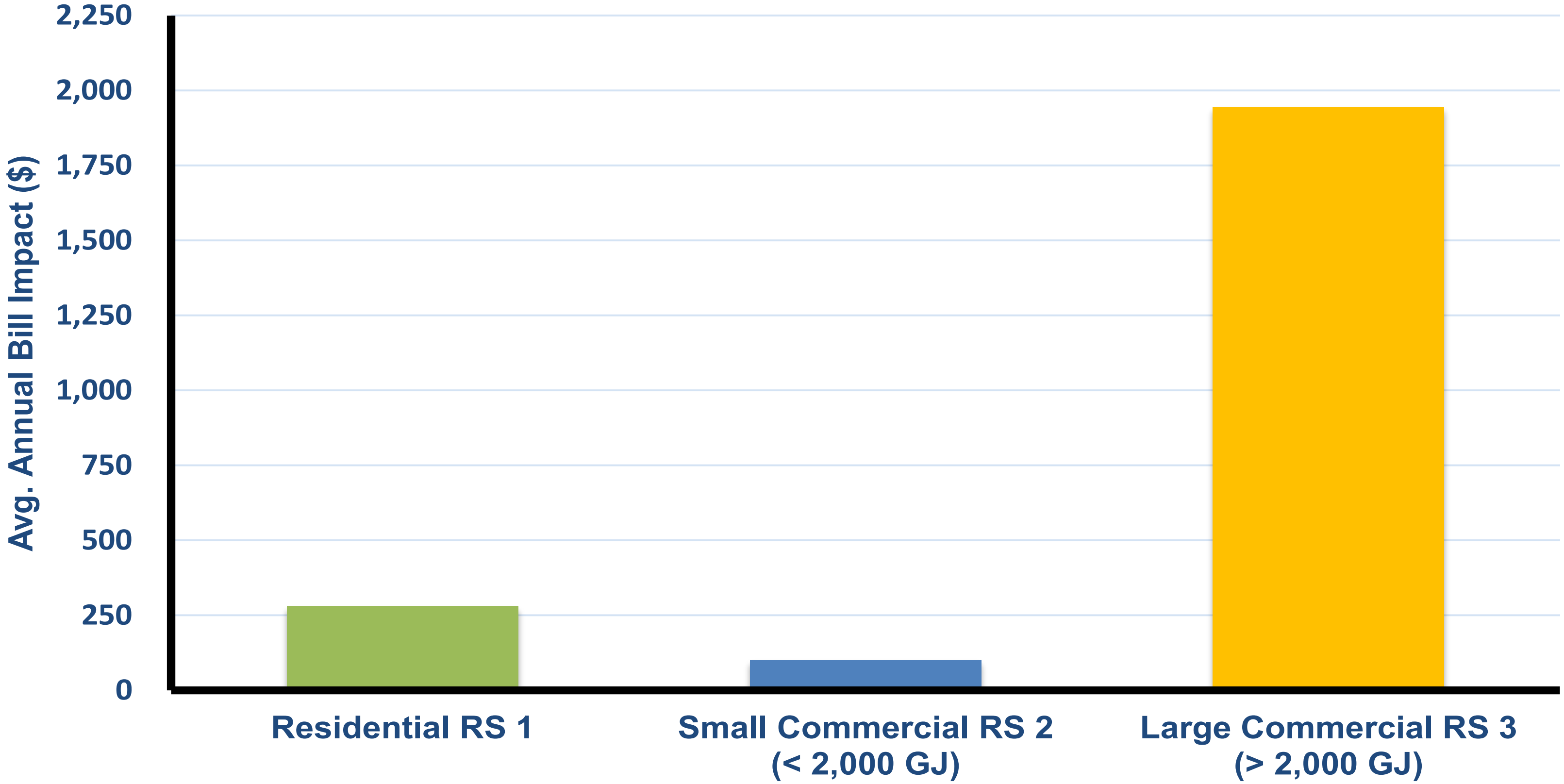
Options to Common Rates for FEFN

- Common Rates for all components (Delivery, Cost of Gas, and Storage and Transport) with phase-in
- Common Rates for Delivery and Cost of Gas Only (with or without phase-in)
- Separate phase in for residential and commercial customers

Option 1 – Common Rates for All Billing Components (Delivery, Cost of Gas and Storage & Transport)

Option 1 – Common Rates for All Components

Avg. Annual Bill Impact to Fort Nelson Customers - 2022 ($)



Note - Annual bill impact reflects the impact from common rates only, does not include general rate increase

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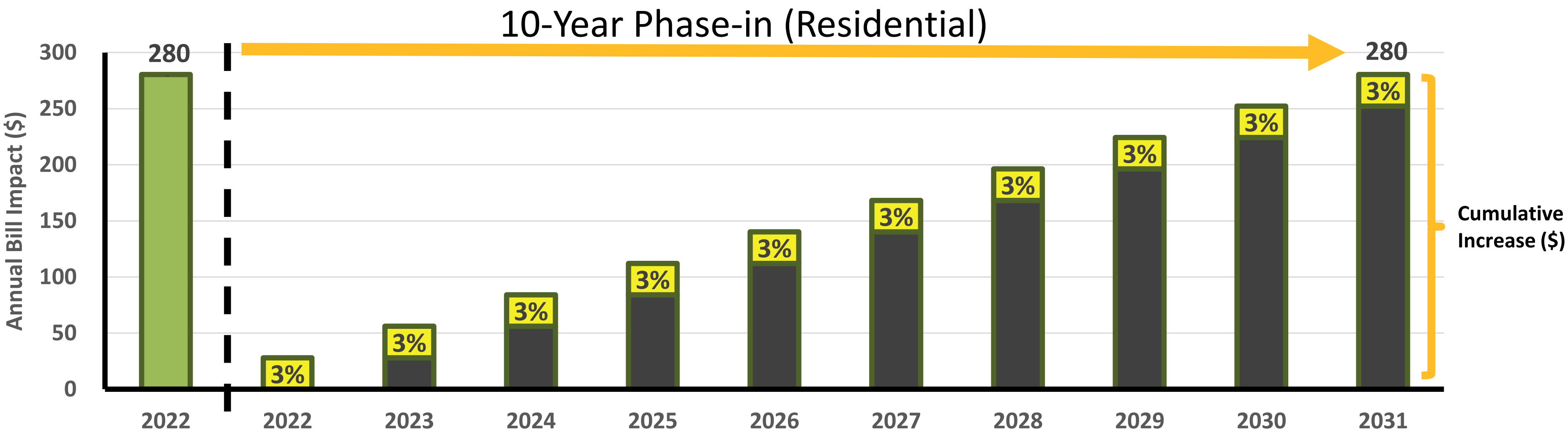
Option 1 – Common Rates for all Components (With 10-year Phase-in)



Note - Annual bill impact reflects the impact from phase in of common rates only, does not include general rate increase

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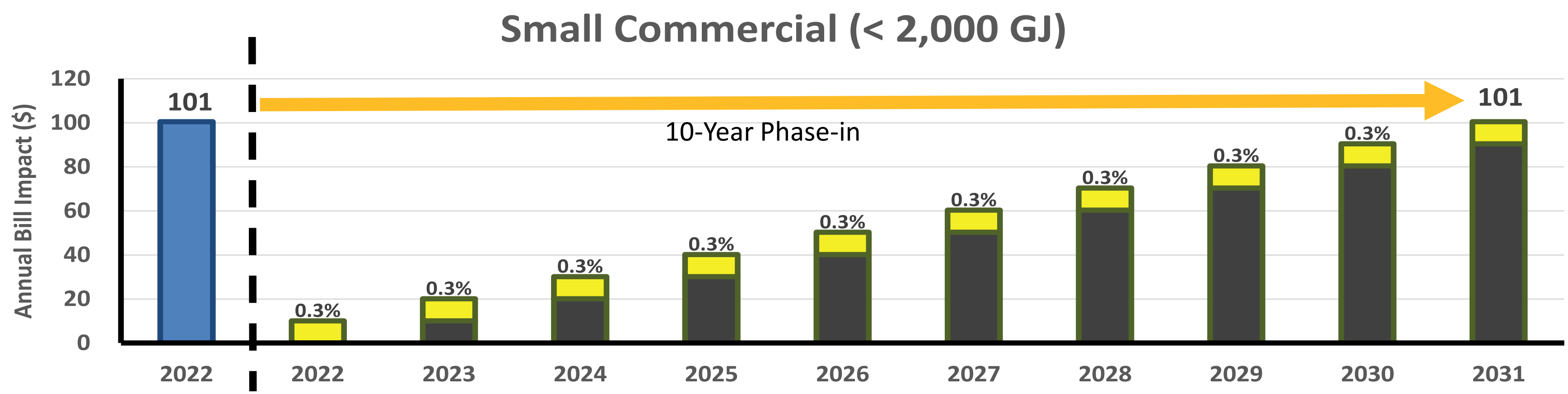
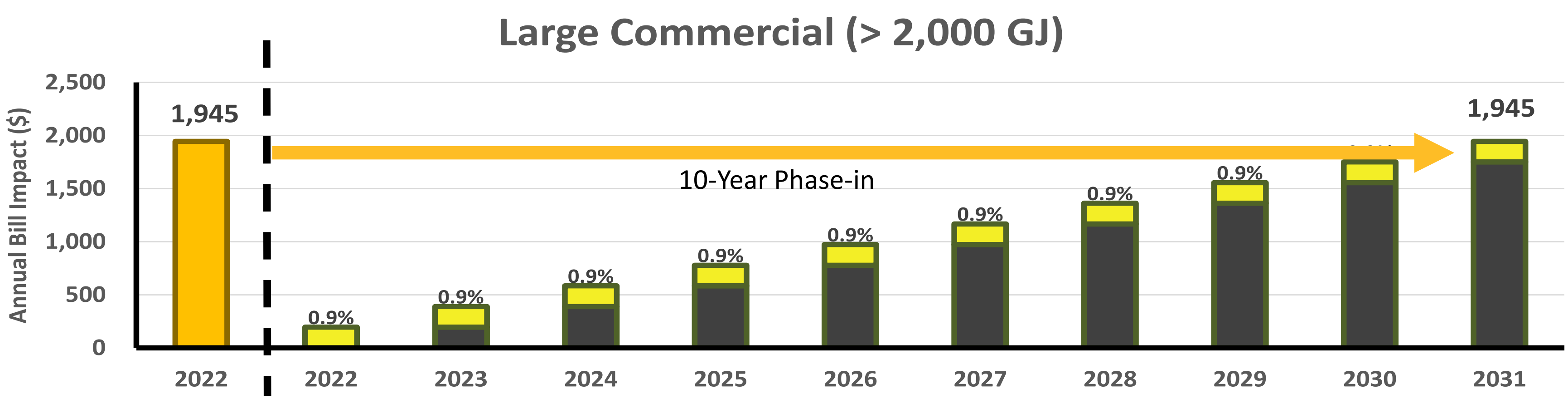
Option 1 – Common Rates for all Components (With 10-year Phase-in)



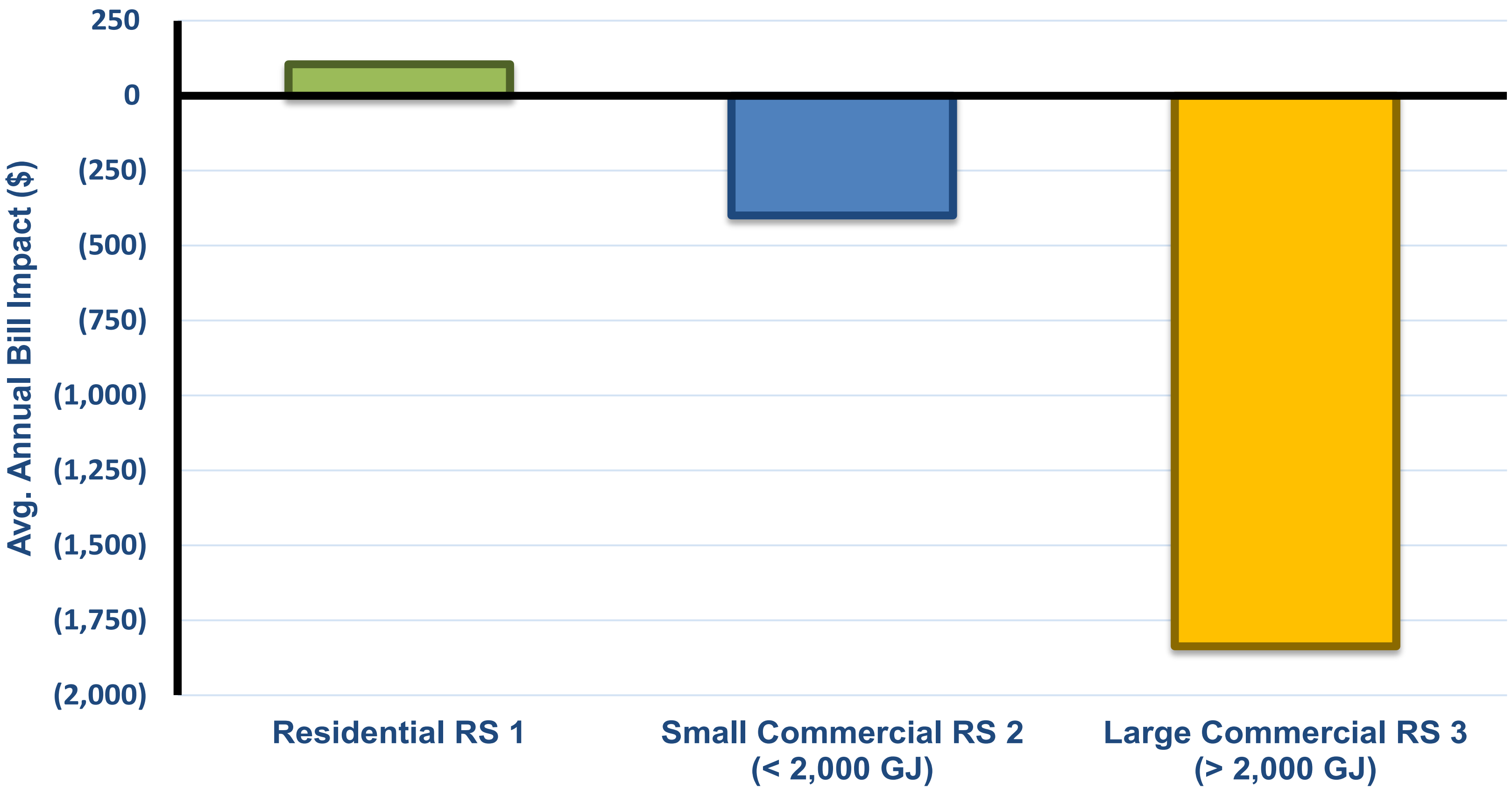


Note - Annual bill impact reflects the impact from phase in of common rates only, does not include general rate increase

Option 2 – Common Rates for Delivery and Cost of Gas only

Option 2 – Common Rates for Delivery and Cost of Gas Only

Avg. Annual Bill Impact to Fort Nelson Customers - 2022 ($)



Note - Annual bill impact reflects the impact from common rates only, does not include general rate increase

Option 2 – Common Rates for Delivery and Cost of Gas Only (With 10-year Phase-in)

Note - Annual bill impact reflects the impact from phase in of common rates only, does not include general rate increase

Summary

- Fort Nelson is the last remaining FEI service area not under postage stamp (common) rates for natural gas service
- Common Rates provide:
  - Rate stability over time for Fort Nelson customers
  - A broader customer base to absorb localized infrastructure investments and changes in customer demand volumes
- FEI is exploring different options for Common Rates for Fort Nelson, including:
  - Common rates for a combination of delivery, cost of gas, and storage & transport
  - Phase-in options

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Next Steps

1. Customer Info Session and Feedback Spring 2021
2. Application Filing May 2021
3. BCUC Regulatory Process (Summer – Fall 2021)
4. **BCUC Decision (Winter 2021)**

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Contact us at
fortnelson.customers@fortisbc.com

For application updates, check out
fortisbc.com/fortnelson

Thank you

Energy at work FORTIS BC

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Appendix C-2

PAID AND SOCIAL MEDIA ADVERTISEMENTS AND MEDIA OUTREACH

ALASKA HIGHWAY NEWS

Fort Nelson town hall talks gas rates

Apr 22, 2021 9:53 AM By: Matt Preprost

A virtual town hall is planned in Fort Nelson next week to discuss FortisBC natural gas rates.

The company says it is applying to the BC Utilities Commission to integrate its Fort Nelson rates with the rest of its provincial customer base "so all customers pay the same rate for natural gas."

"We're actively upgrading our natural gas infrastructure in Fort Nelson to continue to deliver safe and reliable energy to our customers. Delivery rates for Fort Nelson customers have been increasing to cover the upgrade costs," the company said in a public notice.

"As these upgrades continue, the costs are covered by approximately 2,400 customers in Fort Nelson. By merging Fort Nelson into our larger customer base, the cost of these upgrades will be spread out over a million customers."

The town hall is scheduled for Tuesday, April 27, at 6 p.m.

To learn more about the proposal, and to register, click here.

Email Managing Editor Matt Preprost at editor@ahnfsj.ca.

Comments (0)

Moose FM Live

New date for Fort Nelson virtual town hall to talk gas rates

Laura Briggs
Apr 22, 2021 10:41 AM

(Stock)

FORT NELSON, B.C. – FortisBC is hosting a virtual town hall on April 27th for Fort Nelson customers to discuss their natural gas rates.

Two sessions were originally scheduled for March 30th but were eventually postponed.

The company will also be applying to the British Columbia Utilities Commission (BCUC) so that Fort Nelson residents will be paying the same natural gas rates as the rest of the province.

The FortisBC delivery rates for Fort Nelson customers have been increasing to cover upgrade costs as the company works to upgrade its infrastructure in the Fort Nelson area. As the upgrades continue, the costs are covered by around 2,400 customers in Fort Nelson.

FortisBC hopes that by merging Fort Nelson into its larger customer base, the upgrades' cost will spread over a million customers.

FortisBC is looking to hear from Fort Nelson residents and will be holding the town hall session on Tuesday, April 27th at 6 p.m. All Fort Nelson customers are encouraged to join and learn about what they can expect in the coming months.

FortisBC asks that residents register and complete a pre-session survey by Friday, April 23rd.

FortisBC will post the presentation on their website once it becomes available for those unable to attend.

More Local News from your community

PRRD gives recommendations on Site C Hauling plan
FORT ST. JOHN, B.C. - The PRRD has made three recommendations for the Site C Hauling amendment

3 hours ago

NOVA Gas North Corridor Expansion Project approved
OTTAWA, ON. - The NOVA Gas 2023 North Corridor System Expansion project has been approved by the

4 hours ago

Site C employment numbers rise for March
FORT ST. JOHN, B.C. - The number of Site C workers rose in March 2021. There were 4,321 Site C workers in

4 hours ago

Dawson Creek RCMP release tips for vehicle theft
DAWSON CREEK, B.C. -The Dawson Creek RCMP will be releasing monthly property crime prevention tips to

4 hours ago

Most Read Stories

[UPDATE: STARS responds to traumatic injury near Pink Mountain](https://energeticcity.ca)

Apr 06, 2021

Get local news in your inbox each day

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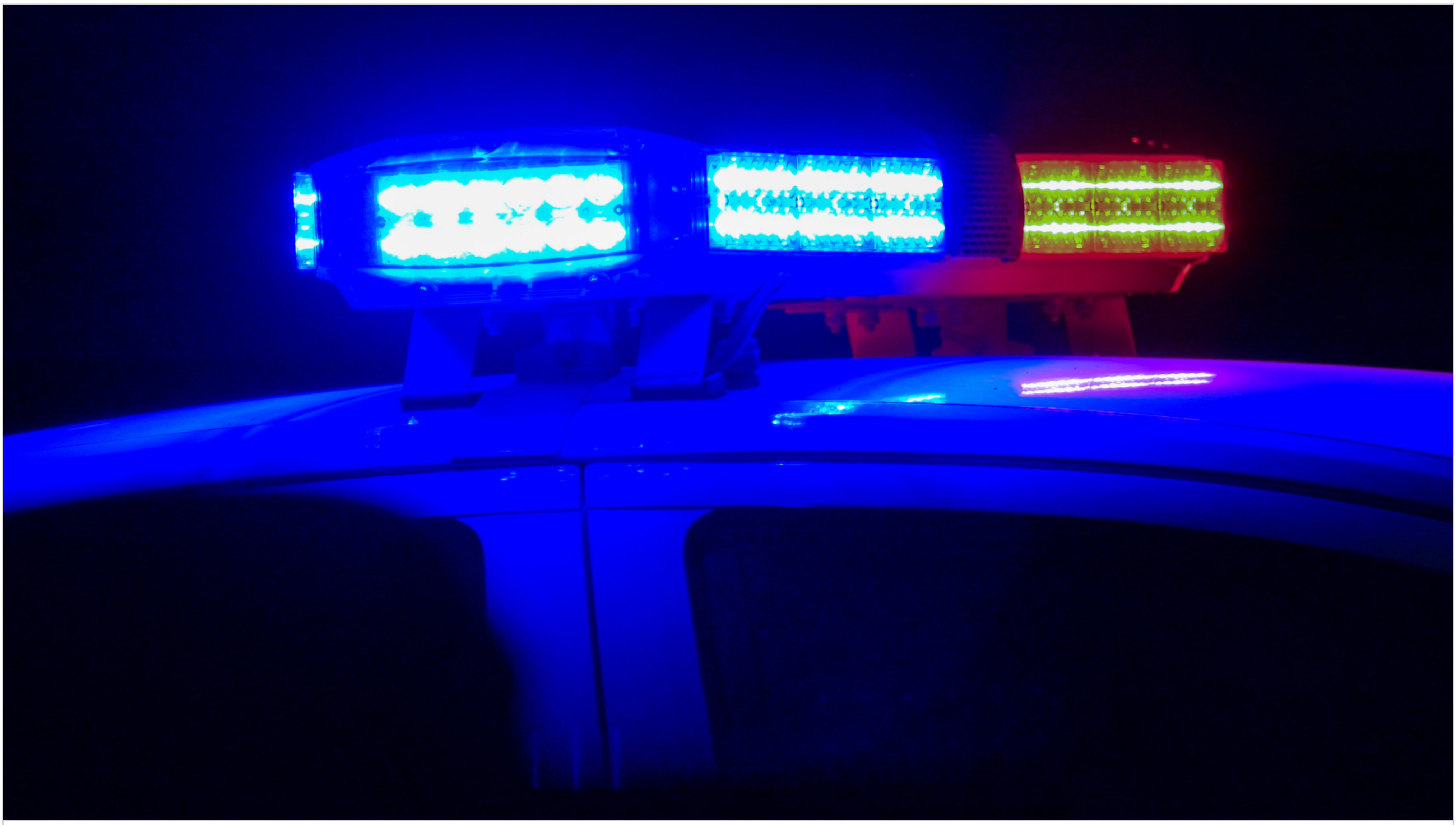
[Fort St. John RCMP arrest male after female stabbed](#)

Apr 25, 2021



[RCMP investigate suspicious death in Fort Nelson](#)

Apr 26, 2021

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Energy at work FORTIS BC™

Join us at a virtual town hall

Tuesday, April 27, 2021 at 6:00 p.m. PST

We're applying to the British Columbia Utilities Commission to merge the rates of our Fort Nelson customers with the rest of our natural gas customers. By doing so, Fort Nelson customers will have more stable natural gas rates over the coming years. We'd like to connect first, and invite you to a virtual town hall for more information. To register, please visit **fortisbc.com/fortnelson**.

Connect with us

21-018.4 Ft_Nelson_print-ad_9.842x10_P3.indd 1 4/9/2021 3:30:10 PM

Appendix C-3

ONLINE SURVEY AND RESULTS

Fort Nelson Common Rates Application

Virtual town hall survey

Name *

First Last

Email *

Would you be supportive of moving to common rates if it decreased rates for commercial customers while increasing rates for residential customers?

- Yes
- No
- Undecided

If common rates are approved by the BCUC, how would you like to see that change implemented:

- No phase-in
- 5-year phase-in
- 10-year phase-in
- 15-year phase-in

Would you be interested in a phase-in option that is tailored for residential, small commercial and large commercial customers?

- Yes
- No
- Undecided

What additional information would you like to be provided with regarding the common rates application?

What are you most interested in learning more about at the virtual town hall?

- [ ] Customer service
- [ ] Changes to rates
- [ ] Billing and rates
- [ ] Rebate programs
- [ ] Natural gas service and safety
- [ ] Other

How would you like to be communicated with during this project?

- [ ] Virtual town hall sessions
- [ ] Fortisbc.com project webpage
- [ ] Notification letter
- [ ] Project email updates

If we hosted an in-person event (after the pandemic) would you be interested in participating?

○ Yes ○ No

To ensure compliance with Canada's Anti-Spam Legislation (CASL), we require your consent to communicate with you by email. *

- [ ] I agree to receive emails from FortisBC news and updates regarding the Fort Nelson Common Rates Application. You may withdraw your consent to receive such emails from FortisBC at any time.

FortisBC collects, uses and discloses your personal information in accordance with the Personal Information Protection Act (British Columbia) and FortisBC's Privacy Policy. Contact fortnelson.customers@fortisbc.com for more details.

Submit

Fort Nelson Common Rates Application – Online Survey Report

Location: [Fort Nelson Common Rates Application (fortisbc.com)]

Period: March 15, 2021 to April 30, 2021

Total respondents: 18

	No	Yes	Undecided	
Would you be supportive of moving to common rates if it decreased rates for commercial customers while increasing rates for residential customers?	10	2	3	

	15-year phase-in	5-year phase-in	No phase in	
If common rates are approved by the BCUC, how would you like to see that change implemented?	4	6	3	

	Yes	No	Undecided	
Would you be interested in a phase-in option that is tailored for residential, small commercial and large commercial customers?	3	5	6	

	Changes to rates	Billing and rates	Rebate programs	Natural gas service and safety
What are you most interested in learning more about at the virtual town hall?	15	6	3	2

	Virtual town hall sessions	Webpage	Notification letter	Email
How would you like to be communicated with during this project?	7	3	1	12

	Yes	No		
If we hosted an in-person event (after the pandemic) would you be interested in participating?	14	4		

What additional information would you like to be provided with regarding the common rates application?
I attended the virtual presentation. Fortis described the rate increase that Fort Nelson customers have had due to the Muskwa River project. What are the near term maintenance and upgrade projects planned for Fort Nelson and what are the implications to natural gas costs for Fort Nelson customers due to the planned work (exclusive of any other commodity or shipping increases, or reduction in Customer numbers or usage)?
I would like to see reduced rates for residential customers!
Is there an example of other communities or districts in BC where Fortis Gas has put common rates in place, is where and when was this done abs which communities did it impact , did those communities see decreases rate?
What will the change cost the average residential customer?
We need transparent, understandable (to the lay person) rate comparisons and transparent, understandable future considerations.
If it is approved, what is the forecast proposed increase for Fort Nelson Residential Customers, in dollar terms and percentage?
Why Fortis thinks this change is acceptable, you already gouge us on the transportation of the gas that only travels 25km now you need to explain why you think we should pay the same transportation rates as Vancouver 1600 km of pipeline south.
With a natural gas plant in Fort Nelson, should our rates not be lower that far distant communities??

Appendix C-4

COMMON RATES FREQUENTLY ASKED QUESTIONS (FAQ)

FAQ PRESS

TOPIC: FORT NELSON COMMON RATES APPLICATION

DATE: JUNE 8, 2021

Background (internal use)

Fort Nelson has historically had a separate rate base. As such, FortisBC customers in Fort Nelson paid different natural gas rates from FortisBC's other customers. Fort Nelson customers have generally had lower rates than FortisBC's other natural gas customers in the province. With ongoing work required on the local infrastructure, the added cost to Fort Nelson customers could become prohibitive, so FortisBC is looking to move Fort Nelson customers to common rates with the rest of its natural gas customers. Without moving to common rates, Fort Nelson customers would have to bear all of the associated costs with the infrastructure upgrades.

We received the questions below from Fort Nelson residents at a virtual town hall session. We'll post these questions and answers on the dedicated webpage to provide information and be transparent with all our customers.

For program inquiries, contact:

Program enquiries – Matt Mason – community and Indigenous relations manager, 250-212-6428

Media enquiries – Diana Sorace – corporate communications advisor, 604-328-0790

FAQ (external use)

Will storage and transport rates, and delivery rates remain unchanged for Fort Nelson customers?

We are applying to the regulator to move Fort Nelson customers to common rates with the rest of FEI's service areas. Until we receive the British Columbia Utilities Commission's ruling, we cannot confirm if the rates will remain unchanged or not.

Why are Fort Nelson customers paying the same rates as everyone else, when the natural gas comes from Fort Nelson?

Your natural gas bill includes a delivery component and a commodity component. The delivery portion of the natural gas bill is not influenced by Fort Nelson's proximity to natural gas production, it is instead related to FortisBC's recovery of the costs of our operations such as our distribution assets, labour, and facilities in Fort Nelson. This delivery portion of Fort Nelson customer rates has historically been more volatile compared to the larger FortisBC service area and has been steadily increasing in recent years due to the cost of infrastructure upgrades for safety and reliability purposes.

The benefit for Fort Nelson customers paying the same rates as everyone else will be the lessened future rate impact since the costs of these upgrades for safety and reliability purposes will be spread over all of FortisBC's million plus customers instead of just Fort Nelson's approximately 2,400 customers.

We are exploring a number of common rates options and are looking at potential options which recognize the current differences in Fort Nelson's commodity related charges. Additionally, and depending on the common rate option being considered, commercial customers may experience savings in their bills as a result of moving to common rates.

What are the benefits to Fort Nelson customers for having the same rates as all other FortisBC natural gas customers?

FortisBC is upgrading its natural gas infrastructure in Fort Nelson in order to continue to deliver safe and reliable energy to its customers. Rates for Fort Nelson customers have been steadily increasing to cover the cost of these upgrades. As these upgrades continue, the cost of these upgrades are currently covered by approximately 2,400 customers in Fort Nelson. By merging Fort Nelson into our larger rate base, the cost of these upgrades will be spread out over a million customers. By spreading the cost of future upgrades across a larger rate base, future rate increases may be lessened.

Will Fort Nelson customers be paying more overall?

While natural gas rates for Fort Nelson customers may increase in the immediate future, this decision will benefit customers in the long term.

This change will spread future costs of upgrading our natural gas infrastructure in Fort Nelson over the entire FortisBC natural gas customer base versus approximately 2,400 customers in Fort Nelson.

If this change were not made, Fort Nelson customers can be expected to see continual increases to rates over the next several years.

Is FortisBC planning more system improvements in the area?

There are several upgrades that our system in Fort Nelson requires over the coming years. That is why this common rates application makes sense, so Fort Nelson residents are not forced to bear the financial burden of these upgrades on their own.

With this proposed rate change, will FortisBC make more money?

The move to common rates is revenue-neutral for FortisBC.

While rate changes may be smoother - currently if we look at 2021 rates Fort Nelson is about 25 per cent less than the Mainland based on the same usage. What is planned that would bring that gap closer?

Currently, natural gas rates (including delivery, cost of gas, and storage & transport) for Fort Nelson residential customers are about 25 percent lower than the rest of FortisBC customers while small and large commercial customers' rates are about two percent and seven percent lower than that of FortisBC customers. FortisBC is exploring a number of different common rates options in order to mitigate the difference in rates between Fort Nelson customers and the rest of FortisBC.

FortisBC is upgrading its natural gas infrastructure in Fort Nelson in order to continue to deliver safe and reliable energy to its customers. Rates for Fort Nelson customers have been steadily increasing to cover the cost of these upgrades. As these upgrades continue, the cost of these upgrades are currently covered by approximately 2,400 customers in Fort Nelson. By merging Fort Nelson into our larger rate base, the cost of these upgrades will be spread out over a million customers. By spreading the cost of future upgrades across a larger rate base, future rate impacts for Fort Nelson customers may be lessened.

If the application is approved, do customers need to do anything or will the change be reflected on their bills? Will bills look any different?

Fort Nelson customers won't need to do anything differently. Everything will work the same way and bills will look the same. The only difference customers will see are different rates on the bill that aligns them with the rest of our customers.

Why is the delivery charge for business higher here than for other FortisBC customers? We are lateral from the plant.

Delivery charge is the portion of the natural gas bill where FortisBC recovers the costs of the natural gas system and our daily operations. It is set independently between the FortisBC service area and Fort Nelson service area, and the costs allocated to the commercial rate classes will depend on a number of factors such as demand, customer mix, and number of customers. Fort Nelson has a different customer mix between different rate classes than FortisBC and at the moment, no industrial customers, which could lead to Fort Nelson commercial rate classes having higher a delivery charge than other FortisBC commercial customers.

So to go to common rates we are looking at ~30 per cent increase for residential?

This will depend on the options of common rates for Fort Nelson. If common rates is for delivery charge only, the bill impact to residential customers is estimated to be around $100 per year but commercial customers will see savings in their bill ranging from around $300 to $2,000 per year, depending on the consumption level. If common rates is with all three components of the natural gas bill (i.e. delivery, cost of gas, and storage & transport), then the bill impact to residential customers is estimated to be around $280 per year.

I feel that my bill has been much larger than the forecasted $280/year increase - just for this past year. I am very concerned about the current costs this winter already. Can you elaborate more on why our FortisBC costs were so high?

Natural gas bills are correlated to how much energy you use. We do have programs in place to help our customers use less energy. We encourage our customers to visit our website to learn more about their energy efficiency and rebate options.

We are hearing about the possible advantages - what are the possible disadvantages? Will there be further public information sessions?

In the short term, Fort Nelson customers will see an increase to their gas bill due to aligning their rates with the rest of our customer base. However, the move to common rates is expected to benefit Fort Nelson customers in the long term.

If we receive more public inquiries and its clear that another information session is required, we will happily organize another one.

Does this add any benefits for any rebates or green house building upgrade?

This application is not related to rebates or building upgrades; however, we encourage our customers to visit our website to learn more about our energy efficiency and rebate programs.

Where does Fortis store the natural gas that Fort Nelson customers consume? How much does that cost Fortis?

Although the charge to Fort Nelson has the same name as the charge for FortisBC, which is “Storage and Transport” Charge, there is no physical storage of the natural gas that is supplied to Fort Nelson, and therefore, there are no storage costs charged to Fort Nelson customers. The “Storage and Transport” Charge for Fort Nelson customers only includes the costs of transportation, which is the cost to physically move the natural gas from the Fort Nelson plant to Fort Nelson. For 2020, the transportation costs for Fort Nelson are approximately $20,000.

Is there a program to help with high bills such as a payment plan?

Absolutely. Our customer contact centre is available to help our customers, and we’ll work with you to find a solution tailored to your needs. Our natural gas customers can call us at 1-888-224-2710 or email us at gas.customerservice@fortisbc.com.

How does this work if the customer uses a different gas suppler?

FortisBC is the natural gas supplier for the region. Our customers do have the option of working with third-party natural gas marketers through our Customer Choice program. Whether you choose to purchase natural gas from an independent gas marketer or from FortisBC, we’ll continue to deliver the gas to your home through the pipelines we own and operate. We also read natural gas meters and provide 24-hour emergency service for all natural gas customers.

Appendix C-5

FORT NELSON REGIONAL COUNCIL PRESENTATION

Fort Nelson Common Rates Application

Regional Council Presentation

Monday, June 14, 2021

Agenda

- Introductions
- Who we are
- Why we are filing for common rates and how the application review process works
- Overview of common rates options
- Questions

Who is FortisBC?

FortisBC is an electricity, natural gas and renewable energy utility in the province of BC, a subsidiary of Newfoundland-based Fortis Inc., Canada's largest private utility company.

Who is FortisBC?

BC's largest energy provider

- more than 2,400 employees
- deliver natural gas, electricity, renewable natural gas and innovative energy solutions
- 1.2 million customers in 135 communities, including 57 Indigenous communities

Sustainability in all we do

Sustainability is not something we do. It's how we do everything

Our sustainability framework:

- supporting our customers
- working with our partners and communities
- protecting the environment
- investing in our employees

Energy at work FORTIS BC

Energy at work FORTIS BC™

Common Rates Application for the Fort Nelson Service Area (FEFN)

FortisBC is regulated by the British Columbia Utilities Commission (BCUC)

- The BCUC is an independent agency of the provincial government that is responsible for regulating energy utilities in BC like FortisBC
- The BCUC is an economic regulator and is governed by the *Utilities Commission Act*
- FortisBC must apply to the BCUC for approval to do such things as set/change customer rates, build capital projects, and enter into energy supply agreements

Energy at work FORTIS BC

Filing an Application with BCUC

Public Hearing Process

Application
- FEI files Application
- A regulatory timetable is established by the BCUC
- FEI provides public notice through various form of media (newspaper, website, Twitter, etc.)

Public Participation
- Register as Intervener; or
- Register as Interested Party; or
- Submit a letter of comment

Evidence Gathering
- Written information requests (IRs) issued to the Applicant from the BCUC and interveners, with written responses provided by the Applicant (could involve multiple rounds of IRs)
- Potential oral process, such as workshop or streamlined review process (SRP)

Arguments
- Written arguments from both Applicant and Intervener(s)
- Reply argument from Applicant

BCUC Decision
- BCUC will issue an order and decision on the Application

Energy at work FORTIS BC

Why are we proposing common rates now?

BCUC Decision and Order G-48-19, page 11:

"Accordingly, the Panel directs FEI to include in the next RRA for FEFN, a discussion of the potential for postage stamping rates in FEFN along with the rest of FEI…"

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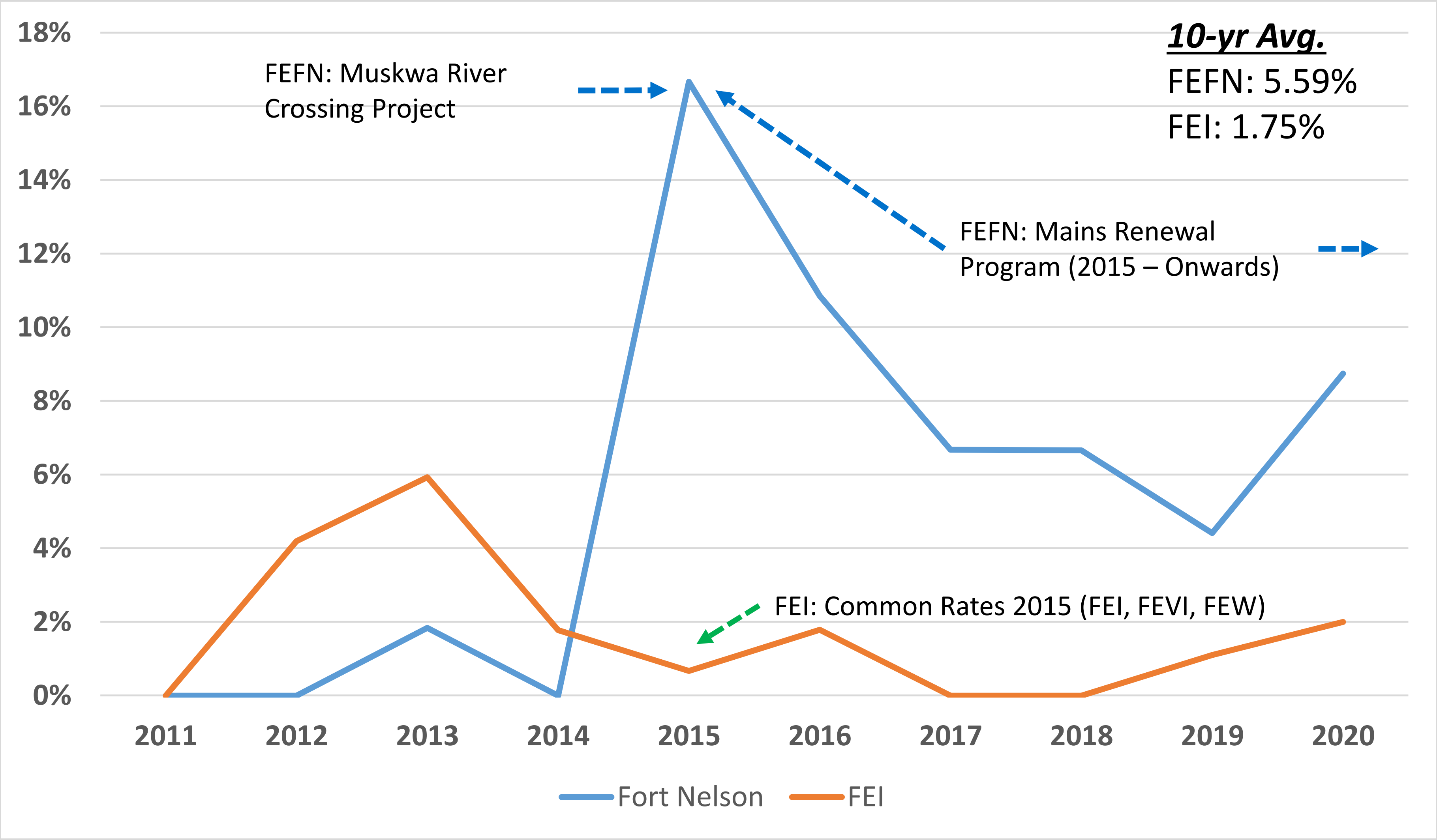
Benefits of Common Rates

- Delivery rate stability over time for Fort Nelson customers
- A broader customer base to absorb localized infrastructure investments
- Limits the impact of changes in Fort Nelson customers' natural gas demand volume on rates

Energy at work FORTIS BC

10-Year Delivery Rate Change (FEFN vs. FEI)



Overview of Common Rate Options for Fort Nelson

Components of Natural Gas Rates

Delivery

- Recovery for natural gas system and daily operations
- Includes variable and fixed costs
- The cost of *delivering* natural gas through FEI/FEFN's natural gas system to your home or business

Cost of Gas

- Part of the commodity related charges
- Market price of natural gas
- Flow-though (No mark up)

Storage and Transport

- Part of the commodity related charges
- 3rd party costs to store and transport natural gas to Fort Nelson distribution system
- Flow-though (No mark up)

Potential Options for Common Rates

- Common rates for *delivery* rates only
- Common rates for *all rate components* (delivery, cost of gas, and storage and transport)
- Different phase-in options for each customer class (i.e. different options for phasing in common rates for residential customers and commercial customers)

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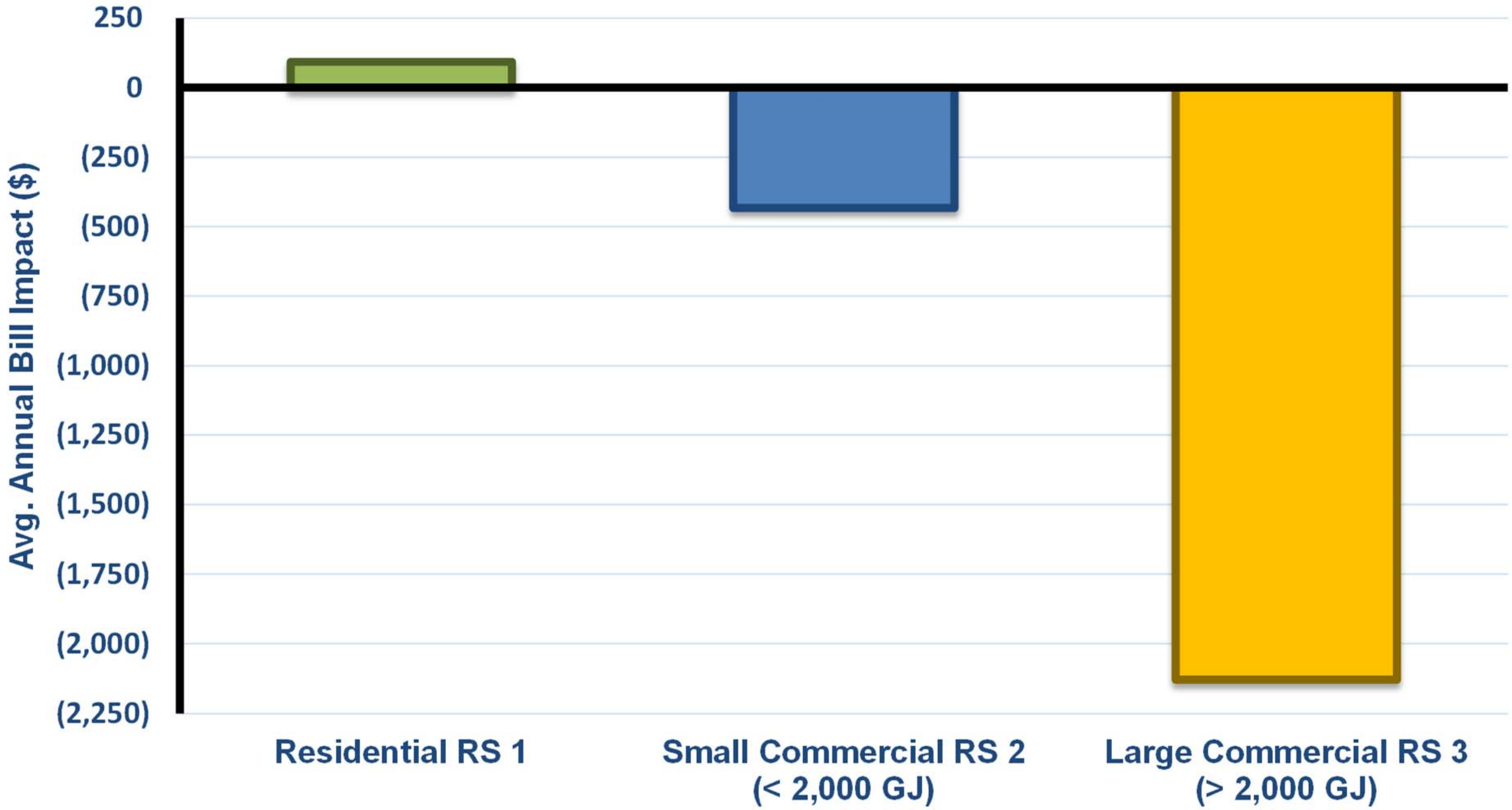
Option 1 – Common Rates for Delivery Only

Avg. Annual Bill Impact to Fort Nelson Customers - 2022 ($)

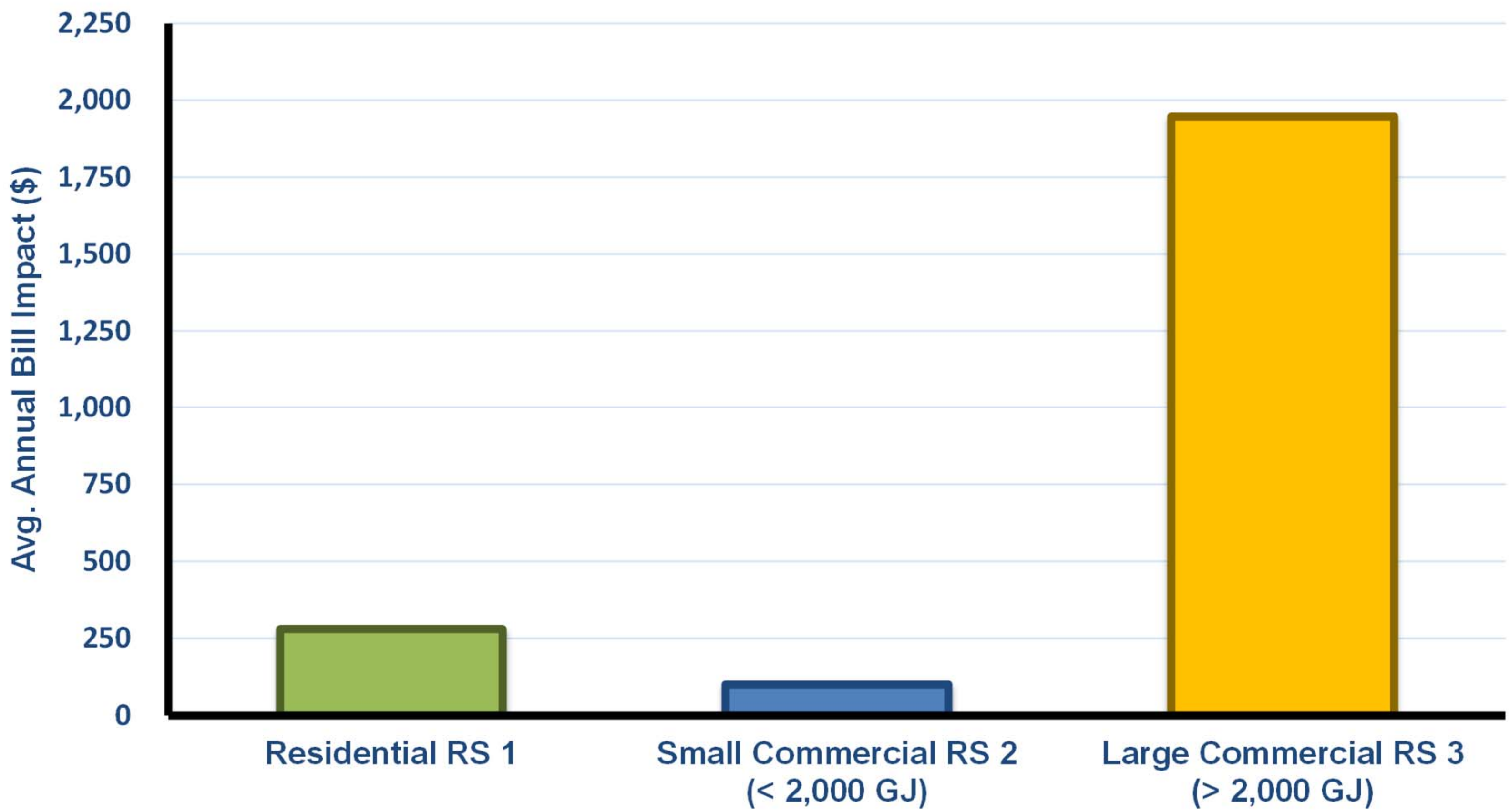


Note - Annual bill impact reflects the impact from common rates only, does not include general rate increase and rate riders

Energy at work FORTIS BC

Option 2 – Common Rates for All Components

Avg. Annual Bill Impact to Fort Nelson Customers - 2022 ($)



Note - Annual bill impact reflects the impact from common rates only, does not include general rate increase and rate riders

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Example of Phase-in: 10 years for Delivery Rates Only

Note - Annual bill impact reflects the impact from phase in of common rates only, does not include general rate increase and rate riders

Summary

- Fort Nelson is the last remaining FEI service area not under postage stamp (common) rates for natural gas service
- Benefits of Common Rates:
  - Delivery rate stability over time for Fort Nelson customers
  - A broader customer base to absorb localized infrastructure investments
  - Limits the impact of changes in Fort Nelson customers' natural gas demand volume on rates
- FEI is exploring different Common Rates options, including:
  - Common rates for delivery, cost of gas, and storage & transport
  - Common rates for delivery only
  - Phase-in options

Thank you

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Appendix C-6

FEI'S STATEMENT OF INDIGENOUS PRINCIPLES

Statement of Indigenous Principles

FortisBC is committed to building effective Indigenous relationships and to ensuring we have the structure, resources and skills necessary to maintain these relationships.

To meet this commitment, the actions of the company and its employees will be guided by the following principles:

- FortisBC companies acknowledge, respect and understand that Indigenous Peoples have unique histories, cultures, protocols, values, beliefs and governments.
- FortisBC supports fair and equal access to employment and business opportunities within FortisBC companies for Indigenous Peoples.
- FortisBC will develop fair, accessible employment practices and plans that ensure Indigenous Peoples are considered fairly for employment opportunities within FortisBC.
- FortisBC will strive to attract Indigenous employees, consultants and contractors and business partnerships.
- FortisBC is committed to dialogue through clear and open communication with Indigenous communities on an ongoing and timely basis for the mutual interest and benefit of both parties.
- FortisBC encourages awareness and understanding of Indigenous issues within its work force, industry and communities where it operates.
- To achieve better understanding and appreciation of Indigenous culture, values and beliefs, FortisBC is committed to educating its employees regarding Indigenous issues, interests and goals.
- FortisBC will ensure that when interacting with Indigenous Peoples, its employees, consultants and contractors demonstrate respect, and understanding of Indigenous Peoples' culture, values and beliefs.
- To give effect to these principles, each of FortisBC's business units will develop, in dialogue with Indigenous communities, plans specific to their circumstances.

Appendix D

PROPOSED FEI TARIFF AMENDMENTS FOR COMMON RATES WITH FEFN

FORTISBC ENERGY INC.
FORT NELSON SERVICE AREA

GAS TARIFF

STATING TERMS AND CONDITIONS AND RATE SCHEDULES FOR GAS SERVICE IN THE FORT NELSON SERVICE AREA OF BRITISH COLUMBIA

FortisBC Energy Inc. Fort Nelson Service Area Gas Tariff originally effective March 1, 2011 and all subsequent amendments up to and including December 31, 2022 is cancelled and no longer in effect.

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FORTISBC ENERGY INC.

RATE SCHEDULE 1

RESIDENTIAL SERVICE

Rate Schedule 1: Residential Service

Available

This Rate Schedule is available in all territory served by FortisBC Energy, provided adequate capacity exists on the FortisBC Energy System.

Applicable

This Rate Schedule is applicable to firm Gas supplied at one Premise for use in approved appliances for all residential applications in single-family residences, separately metered single-family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments.

	Mainland and Vancouver Island Service Area	Fort Nelson Service Area
Delivery Margin Related Charges		
1. **Basic Charge** per Day	**$ 0.4085**	**$ 0.4085**
2. Rider 2 per Day	$ 0.0131	$ 0.0131
Subtotal of per Day **Delivery** Margin Related Charges	**$ 0.4216**	**$ 0.4216**
3. Delivery Charge per Gigajoule	$ X.XXX	$ X.XXX
4. Rider 3 per Gigajoule	$ X.XXX	$ 0.000
5. Rider 4 per Gigajoule	$ 0.000	$ X.XXX
6. Rider 5 per Gigajoule	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X.XXX**	**$ X.XXX**

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	Mainland and Vancouver Island Service Area	Fort Nelson Service Area
Commodity Related Charges		
7. Storage and Transport Charge per Gigajoule	$ X.XXX	$ X.XXX
8. Rider 6 per Gigajoule	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Storage and Transport** Related Charges	**$ X.XXX**	**$ X.XXX**
9. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X.XXX**	**$ X.XXX**

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Delivery Margin Related Riders

Rider 2 **Clean Growth Innovation Fund Account** - Applicable to Mainland and Vancouver Island and Fort Nelson Service Area Customers for the Year ending December 31, 2023. C

Rider 3 **Biomethane Variance Account** - Applicable to Mainland and Vancouver Island Service Area Customers for the Year ending December 31, 2022. C

Rider 4 **Fort Nelson Residential Common Rate Phase-in Rate Rider** - Applicable to Fort Nelson Service Area Residential Customers for the Year ending December 31, 2023.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Mainland and Vancouver Island and Fort Nelson Service Area Customers for the Year ending December 31, 2023. C

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Commodity Related Riders

Rider 1 (Reserved for future use.) C/N/O

Storage and Transport Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to Mainland and Vancouver Island and Fort Nelson Service Area Customers for the Year ending December 31, 2023. C/O

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Rider 8 (Reserved for future use.)

Rider 9 (Reserved for future use.)

Municipal Operating Fee Charge

A Municipal Operating Fee charge is payable (in addition to the above charges), if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) where FortisBC Energy is required to remit such Municipal Operating Fee to the municipality and excluding any Customer from whom FortisBC Energy is not allowed to collect such Municipal Operating Fee. The Municipal Operating Fee charge will be calculated in accordance with the approved methodology.

Minimum Charge per Month

The minimum charge per Month will be the aggregate of the Basic Charge and the Municipal Operating Fee charge (where applicable and calculated in accordance with the approved methodology).

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Pursuant to British Columbia Utilities Commission Order G-302-19, 2020 delivery rates were set on an interim basis for consumption on and after January 1, 2020. Pursuant to British Columbia Utilities Commission Order G-319-20, interim 2020 delivery rates are made permanent for consumption on and after January 1, 2020, up to and including December 31, 2020. Pursuant to British Columbia Utilities Commission Order G-319-20, 2021 delivery rates and delivery rate riders are approved permanent and implemented for consumption on and after January 1, 2021.

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FORTISBC ENERGY INC.

RATE SCHEDULE 2

SMALL COMMERCIAL SERVICE

Rate Schedule 2: Small Commercial Service

Available

This Rate Schedule is available in all territory served by FortisBC Energy, provided adequate capacity exists on the FortisBC Energy System.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of less than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations.

		Mainland and Vancouver Island Service Area	Fort Nelson Service Area
Delivery Margin Related Charges			
1. **Basic Charge** per Day	**$**	**0.9485**	**$ 0.9485**
2. Rider 2 per Day	$	0.0131	$ 0.0131
Subtotal of per Day **Delivery** Margin Related Charges	**$**	**0.9616**	**$ 0.9616**
3. Delivery Charge per Gigajoule	$	X.XXX	$ X.XXX
4. Rider 3 per Gigajoule	$	X.XXX	$ 0.000
5. Rider 5 per Gigajoule	$	X.XXX	$ X.XXX
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$**	**X.XXX**	**$ X.XXX**

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	Mainland and Vancouver Island Service Area	Fort Nelson Service Area
Commodity Related Charges		
6. Storage and Transport Charge per Gigajoule	$ X.XXX	$ X.XXX
7. Rider 6 per Gigajoule	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Storage and Transport** Related Charges	**$ X.XXX**	**$ X.XXX**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X.XXX**	**$ X.XXX**

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Delivery Margin Related Riders

Rider 2 **Clean Growth Innovation Fund Account** - Applicable to Mainland and Vancouver Island and Fort Nelson Service Area Customers for the Year ending December 31, 2023. C

Rider 3 **Biomethane Variance Account** - Applicable to Mainland and Vancouver Island Service Area Customers for the Year ending December 31, 2023. C

Rider 4 **Fort Nelson Residential Common Rate Phase-in Rate Rider** - Applicable to Fort Nelson Service Area Residential Customers for the Year ending December 31, 2023.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Mainland and Vancouver Island and Fort Nelson Service Area Customers for the Year ending December 31, 2023. C

Commodity Cost Recovery Charge Related Riders

Rider 1 (Reserved for future use.) C/N/O

Storage and Transport Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to Mainland and Vancouver Island and Fort Nelson Service Area Customers for the Year ending December 31, 2023. C/O

Rider 8 (Reserved for future use.)

Municipal Operating Fee Charge

A Municipal Operating Fee charge is payable (in addition to the above charges), if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) where FortisBC Energy is required to remit such Municipal Operating Fee to the municipality and excluding any Customer from whom FortisBC Energy is not allowed to collect such Municipal Operating Fee. The Municipal Operating Fee charge will be calculated in accordance with the approved methodology.

Minimum Charge per Month

The minimum charge per Month will be the aggregate of the Basic Charge and the Municipal Operating Fee charge (where applicable and calculated in accordance with the approved methodology).

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Pursuant to British Columbia Utilities Commission Order G-302-19, 2020 delivery rates were set on an interim basis for consumption on and after January 1, 2020. Pursuant to British Columbia Utilities Commission Order G-319-20, interim 2020 delivery rates are made permanent for consumption on and after January 1, 2020, up to and including December 31, 2020. Pursuant to British Columbia Utilities Commission Order G-319-20, 2021 delivery rates and delivery rate riders are approved permanent and implemented for consumption on and after January 1, 2021.

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FORTISBC ENERGY INC.

RATE SCHEDULE 3

LARGE COMMERCIAL SERVICE

Rate Schedule 3: Large Commercial Service

Available

This Rate Schedule is available in all territory served by FortisBC Energy, provided adequate capacity exists on the FortisBC Energy System.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of greater than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations.

	Mainland and Vancouver Island Service Area	Fort Nelson Service Area
Delivery Margin Related Charges		
1. **Basic Charge** per Day	**$ 4.7895**	**$ 4.7895**
2. Rider 2 per Day	$ 0.0131	$ 0.0131
Subtotal of per Day **Delivery** Margin Related Charges	**$ 4.8026**	**$ 4.8026**
3. Delivery Charge per Gigajoule	$ X.XXX	$ X.XXX
4. Rider 3 per Gigajoule	$ X.XXX	$ 0.000
5. Rider 5 per Gigajoule	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X.XXX**	**$ X.XXX**

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	Mainland and Vancouver Island Service Area	Fort Nelson Service Area
Commodity Related Charges		
6. Storage and Transport Charge per Gigajoule	$ X.XXX	$ X.XXX
7. Rider 6 per Gigajoule	$ X.XXX	$ X.XXX
Subtotal of per Gigajoule **Storage and Transport** Related Charges	**$ X.XXX**	**$ X.XXX**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X.XXX**	**$ X.XXX**

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Delivery Margin Related Riders

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Rider 2 **Clean Growth Innovation Fund Account** - Applicable to Mainland and Vancouver Island and Fort Nelson Service Area Customers for the Year ending December 31, 2023. C

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Rider 3 **Biomethane Variance Account** - Applicable to Mainland and Vancouver Island Service Area Customers for the Year ending December 31, 2023. C

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Rider 4 **Fort Nelson Residential Common Rate Phase-in Rate Rider** - Applicable to Fort Nelson Service Area Residential Customers for the Year ending December 31, 2023.

Deleted: (Reserved for future use.)

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to Mainland and Vancouver Island and Fort Nelson Service Area Customers for the Year ending December 31, 2023. C

Deleted: 1

Deleted: G-245-20/G-314-20/G-319-20

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Commodity Cost Recovery Charge Related Riders

Rider 1 (Reserved for future use.) C/N/O

Storage and Transport Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to Mainland and Vancouver Island and Fort Nelson Service Area Customers for the Year ending December 31, 2023. C/O

Deleted: 1

Rider 8 (Reserved for future use.)

Municipal Operating Fee Charge

A Municipal Operating Fee charge is payable (in addition to the above charges), if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) where FortisBC Energy is required to remit such Municipal Operating Fee to the municipality and excluding any Customer from whom FortisBC Energy is not allowed to collect such Municipal Operating Fee. The Municipal Operating Fee charge will be calculated in accordance with the approved methodology.

Minimum Charge per Month

The minimum charge per Month will be the aggregate of the Basic Charge and the Municipal Operating Fee charge (where applicable and calculated in accordance with the approved methodology).

C/

Deleted: Permanent Delivery Rate Establishment¶
Pursuant to British Columbia Utilities Commission Order G-302-19, 2020 delivery rates were set on an interim basis for consumption on and after January 1, 2020. Pursuant to British Columbia Utilities Commission Order G-319-20, interim 2020 delivery rates are made permanent for consumption on and after January 1, 2020, up to and including December 31, 2020. Pursuant to British Columbia Utilities Commission Order G-319-20, 2021 delivery rates and delivery rate riders are approved permanent and implemented for consumption on and after January 1, 2021.¶

d: G-245-20/G-314-20/G-319-20

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Appendix E
FINANCIAL SCHEDULES

Appendix E-1

2022 REVENUE REQUIREMENT FINANCIAL SCHEDULES

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2022
($millions)

Schedule 1

Line No.	Particulars	2022 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ 0.099		
3	Change in Other Revenue	(0.005)	0.094	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	0.041		
7	Capitalized Overhead Rate Change per FEI from 12% to 16%	(0.037)		
8	Capitalized Overhead Change	(0.007)	(0.003)	
9				
10	**DEPRECIATION EXPENSE**			
11	Depreciation Rate Change (Depreciation Study)	(0.030)		
12	Plant Depreciation from Net Additions	0.030	0.000	
13				
14	**AMORTIZATION EXPENSE**			
15	CIAC Rate Change (Depreciation Study)	0.001		
16	CIAC from Net Additions	0.001		
17	Net Salvage Depreciation Rate Change (Depreciation Study)	0.027		
18	Deferrals	0.041	0.070	
19				
20	**FINANCING AND RETURN ON EQUITY**			
21	Financing Rate Changes	(0.010)		
22	Financing Ratio Changes	(0.002)		
23	Lead/Lag Days Change per FEI	(0.022)		
24	Rate Base Growth	0.065	0.031	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes	0.008		
28	Other Income Taxes Changes	0.015	0.023	
29				
30	**Deferred 2021 Revenue Surplus**		(0.132)	
31				
32	**Revenue Deficiency (Surplus)**		$ 0.083	Schedule 12, Line 9, Column 4
33				
34	Non-Bypass Margin @ Existing Rates		2.434	Schedule 12, Line 13, Column 3
35	Rate Change		3.41%	

Schedule 2

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved	2022 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 17,837	$ 18,369	$ 532	Schedule 4, Line 38, Column 3
2	Net Additions	837	1,059	222	Schedule 4, Line 38, Column 5+6+7
3	Plant in Service, Ending	18,674	19,428	754	
4					
5	Accumulated Depreciation Beginning	$ (5,184)	$ (5,397)	$ (213)	Schedule 5, Line 38, Column 5
6	Net Additions	(406)	(384)	22	Schedule 5, Line 38, Column 7+8
7	Accumulated Depreciation Ending	(5,590)	(5,781)	(191)	
8					
9	CIAC, Beginning	$ (1,337)	$ (1,340)	$ (3)	Schedule 6, Line 4, Column 2
10	Net Additions	-	-	-	Schedule 6, Line 4, Column 5+6
11	CIAC, Ending	(1,337)	(1,340)	(3)	
12					
13	Accumulated Amortization Beginning - CIAC	$ 819	$ 844	$ 25	Schedule 6, Line 9, Column 2
14	Net Additions	29	27	(2)	Schedule 6, Line 9, Column 5+6
15	Accumulated Amortization Ending - CIAC	848	871	23	
16					
17	Net Plant in Service, Mid-Year	$ 12,365	$ 12,827	$ 462	
18					
19	Adjustment for timing of Capital additions	$ -	$ -	$ -	
20	Capital Work in Progress, No AFUDC	77	181	104	
21	Unamortized Deferred Charges	(20)	94	114	Schedule 8, Line 23, Column 10
22	Working Capital	81	84	3	Schedule 10, Line 11, Column 3
23					
24	Mid-Year Utility Rate Base	$ 12,503	$ 13,186	$ 683	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION Schedule 3
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars		2022 Forecast	Cross Reference
	(1)		(2)	(3)
1	**CAPEX**			
2				
3	Total Regular Capital Expenditures	$	1,005	
4				
5	Total Special Projects and CPCNs	$	-	
6				
7	**Total Capital Expenditures**	$	1,005	
8				
9				
10	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
11				
12	Regular Capital Expenditures	$	1,005	
13	Add - Capitalized Overheads		156	Schedule 16, Line 18, Column 3
14	Add - AFUDC		-	
15	Gross Capital Expenditures		1,161	
16	Change in Work in Progress		-	
17	**Total Additions to Plant - Regular Capital**	$	1,161	
18				
19	Special Projects and CPCNs	$	-	
20	**Total Additions to Plant - CPCNs**	$	-	
21				
22	**Grand Total Additions to Plant**	$	1,161	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 4

Line No.	Account	Particulars	12/31/2021	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2022	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	461-01	Transmission Land Rights	$ 78	$ -	$ -	$ -	$ -	$ 78	
3	471-01	Distribution Land Rights	20	-	-	-	-	20	
4	402-01	Application Software - 12.5%	182	-	-	21	-	203	
5	402-02	Application Software - 20%	81	-	-	21	(12)	90	
6			$ 361	$ -	$ -	$ 42	$ (12)	$ 391	
7									
8		**TRANSMISSION PLANT**							
9	463-00	Measuring Structures	$ 10	$ -	$ -	$ -	$ -	$ 10	
10	465-00	Mains	5,996	-	-	-	-	5,996	
11	467-10	Measuring & Regulating Equipment	774	-	-	2	-	776	
12	467-20	Telemetering	317	-	-	13	-	330	
13			$ 7,097	$ -	$ -	$ 15	$ -	$ 7,112	
14									
15		**DISTRIBUTION PLANT**							
16	472-00	Structures & Improvements	$ 370	$ -	$ -	$ -	$ -	$ 370	
17	473-00	Services	2,778	-	-	93	(24)	2,847	
18	474-00	House Regulators & Meter Installations	448	-	-	-	-	448	
19	474-02	Meters/Regulators Installations	249	-	-	2	-	251	
20	475-00	Mains	3,719	-	-	225	(21)	3,923	
21	477-10	Measuring & Regulating Equipment	1,905	-	-	730	-	2,635	
22	477-20	Telemetering	424	-	-	-	-	424	
23	478-10	Meters	23	-	-	1	-	24	
24			$ 9,916	$ -	$ -	$ 1,051	$ (45)	$ 10,922	
25									
26		**GENERAL PLANT & EQUIPMENT**							
27	480-00	Land in Fee Simple	$ 1	$ -	$ -	$ -	$ -	$ 1	
28	482-10	Frame Buildings	692	-	-	25	-	717	
29	483-30	GP Office Equipment	-	-	-	-	-	-	
30	483-40	GP Furniture	1	-	-	-	-	1	
31	483-10	GP Computer Hardware	246	-	-	18	(45)	219	
32	483-20	GP Computer Software	(1)	-	-	-	-	(1)	
33	484-00	Vehicles	19	-	-	-	-	19	
34	486-00	Small Tools & Equipment	37	-	-	10	-	47	
35	488-10	Telephone	-	-	-	-	-	-	
36			$ 995	$ -	$ -	$ 53	$ (45)	$ 1,003	
37									
38		**Total Plant in Service**	$ 18,369	$ -	$ -	$ 1,161	$ (102)	$ 19,428	
39									
40		Cross Reference			Schedule 3, Line 20, Column 2	Schedule 3, Line 17, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 5

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2021	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2022	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**INTANGIBLE PLANT**										
2	461-01	Transmission Land Rights	$ 78	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	471-01	Distribution Land Rights	20	0.00%	-	-	-	-	-	-	-	
4	402-01	Application Software - 12.5%	182	12.50%	133	-	23	-	-	-	156	
5	402-02	Application Software - 20%	81	20.00%	35	-	16	(12)	-	-	39	
6			$ 361		$ 168	$ -	$ 39	$ (12)	$ -	$ -	$ 195	
7												
8		**TRANSMISSION PLANT**										
9	463-00	Measuring Structures	$ 10	2.13%	$ 3	$ -	$ -	$ -	$ -	$ -	$ 3	
10	465-00	Mains	5,996	1.46%	855	-	88	-	-	-	943	
11	467-10	Measuring & Regulating Equipment	774	2.12%	340	-	16	-	-	-	356	
12	467-20	Telemetering	317	8.97%	9	-	28	-	-	-	37	
13			$ 7,097		$ 1,207	$ -	$ 132	$ -	$ -	$ -	$ 1,339	
14												
15		**DISTRIBUTION PLANT**										
16	472-00	Structures & Improvements	$ 370	2.15%	$ 148	$ -	$ 8	$ -	$ -	$ -	$ 156	
17	473-00	Services	2,778	2.18%	1,091	-	61	(24)	-	-	1,128	
18	474-00	House Regulators & Meter Installations	448	7.45%	461	-	33	-	-	-	494	
19	474-02	Meters/Regulators Installations	249	4.55%	53	-	12	-	-	-	65	
20	475-00	Mains	3,719	1.35%	797	-	50	(21)	-	-	826	
21	477-10	Measuring & Regulating Equipment	1,905	2.51%	846	-	48	-	-	-	894	
22	477-20	Telemetering	424	3.59%	56	-	15	-	-	-	71	
23	478-10	Meters	23	6.06%	18	-	1	-	-	-	19	
24			$ 9,916		$ 3,470	$ -	$ 228	$ (45)	$ -	$ -	$ 3,653	
25												
26		**GENERAL PLANT & EQUIPMENT**										
27	480-00	Land in Fee Simple	$ 1	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
28	482-10	Frame Buildings	692	3.17%	297	-	22	-	-	-	319	
29	483-30	GP Office Equipment	-	6.67%	-	-	-	-	-	-	-	
30	483-40	GP Furniture	1	5.00%	1	-	-	-	-	-	1	
31	483-10	GP Computer Hardware	246	25.00%	229	-	61	(45)	-	-	245	
32	483-20	GP Computer Software	(1)	12.50%	-	-	-	-	-	-	-	
33	484-00	Vehicles	19	11.07%	19	-	2	-	-	-	21	
34	486-00	Small Tools & Equipment	37	5.00%	6	-	2	-	-	-	8	
35	488-10	Telephone	-	6.67%	-	-	-	-	-	-	-	
36			$ 995		$ 552	$ -	$ 87	$ (45)	$ -	$ -	$ 594	
37												
38		**Total**	$ 18,369		$ 5,397	$ -	$ 486	$ (102)	$ -	$ -	$ 5,781	
39												
40		Cross Reference	Schedule 4, Line 38, Columns 3+4+5									

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	12/31/2021	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2022	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 1,175	$ -	$ -	$ -	$ -	$ 1,175	
3	Transmission Contributions	165	-	-	-	-	165	
4	**Total**	$ 1,340	$ -	$ -	$ -	$ -	$ 1,340	
5								
6	**Amortization**							
7	Distribution Contributions	$ (812)	$ -	$ -	$ (25)	$ -	$ (837)	
8	Transmission Contributions	(32)	-	-	(2)	-	(34)	
9	**Total**	$ (844)	$ -	$ -	$ (27)	$ -	$ (871)	
10								
11	**Net CIAC**	$ 496	$ -	$ -	$ (27)	$ -	$ 469	
12								

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2021	Opening Bal Adjustment	Net Salvage Provision	Retirement Costs / Proceeds on Disp.	12/31/2022	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1		**TRANSMISSION PLANT**								
2	463-00	Measuring Structures	$ 10	0.62%	$ -	$ -	$ -	$ -	$ -	
3	465-00	Mains	5,996	0.42%	10	-	25	(35)	-	
4	467-10	Measuring & Regulating Equipment	774	0.16%	12	-	1	-	13	
5			$ 6,780		$ 22	$ -	$ 26	$ (35)	$ 13	
6										
7		**DISTRIBUTION PLANT**								
8	472-00	Structures & Improvements	$ 370	0.52%	$ 4	$ -	$ 2	$ -	$ 6	
9	473-00	Services	2,778	2.09%	73	-	58	(35)	96	
10	474-00	House Regulators & Meter Installations	448	3.37%	47	-	15	(1)	61	
11	474-02	Meters/Regulators Installations	249	0.00%	1	-	-	-	1	
12	475-00	Mains	3,719	0.50%	(68)	-	19	(19)	(68)	
13	477-10	Measuring & Regulating Equipment	1,905	0.45%	60	-	9	-	69	
14	477-20	Telemetering	424	0.48%	7	-	2	-	9	
15	478-10	Meters	-	0.00%	-	-	-	-	-	
16			$ 9,893		$ 124	$ -	$ 105	$ (55)	$ 174	
17										
18		**GENERAL PLANT & EQUIPMENT**								
19	482-10	Frame Buildings	$ 692	0.37%	$ (3)	$ -	$ 3	$ -	$ -	
20	484-00	Vehicles	19	-3.70%	(1)	-	(1)	-	(2)	
21			$ 711		$ (4)	$ -	$ 2	$ -	$ (2)	
22										
23										
24		**Total**	$ 17,384		$ 142	$ -	$ 133	$ (90)	$ 185	
25										
26		Cross Reference	Schedule 4, Columns 3+4+5							

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 8

Line No.	Particulars	12/31/2021	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2022	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Forecasting Variance Accounts										
2	Revenue Stabilization Adjustment Mechanism (RSAM)	$ (283)	$ -	$ -	$ -	$ -	$ 194	$ (52)	$ (141)	$ (212)	
3	Interest on RSAM	(2)	-	-	-	-	2	-	-	(1)	
4	Gas Cost Reconciliation Account	62	-	(85)	23	-	-	-	-	31	
5	Property Tax Variance	27	-	-	-	(14)	-	-	13	20	
6	Interest Variance Deferral	(13)	-	-	-	8	-	-	(5)	(9)	
7		$ (209)	$ -	$ (85)	$ 23	$ (6)	$ 196	$ (52)	$ (133)	$ (171)	
8											
9	Benefits Matching Accounts										
10	Demand-Side Management (DSM)	$ 216	$ 98	$ 65	$ (18)	$ (38)	$ -	$ -	$ 323	$ 319	
11	2017 Rate Design Application	17	-	-	-	(8)	-	-	9	13	
12	Gains and Losses on Asset Disposition	34	-	-	-	(11)	-	-	23	29	
13	Net Salvage Provision/Cost	(142)	-	90	-	(133)	-	-	(185)	(164)	
14	FEFN Common Rates and 2022 Revenue Requirement Application Costs	37	-	75	(21)	-	-	-	91	64	
15	Billing system costs for FEFN Rate changes	3	-	-	-	(2)	-	-	1	2	
16		$ 165	$ 98	$ 230	$ (39)	$ (192)	$ -	$ -	$ 262	$ 263	
17											
18	Retroactive Expense Accounts										
19											
20	Other Accounts										
21	COVID-19 Customer Recovery Fund	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ 2	
22											
23	**Total Deferred Charges for Rate Base**	$ (42)	$ 98	$ 145	$ (16)	$ (198)	$ 196	$ (52)	$ 131	$ 94	

FORTISBC ENERGY INC. - Fort Nelson

Schedule 9

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	12/31/2021	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2022	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Rate Smoothing Accounts										
2	FEFN Revenue Surplus	$ (89)	$ -	$ (5)	$ -	$ -	$ -	$ -	$ (94)	$ (92)	
3											
4	Benefits Matching Accounts										
5	Demand-Side Management (DSM)	98	(98)	152	(40)	-	-	-	112	56	
6											
7	Other Accounts										
8	FN Right-of-Way Agreement	155	-	9	-	-	-	-	164	160	
9											
10											
11	**Total Deferred Charges for Non Rate Base**	$ 164	$ (98)	$ 156	$ (40)	$ -	$ -	$ -	$ 182	$ 124	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 70	$ 60	$ (10)	Schedule 11, Line 27, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Employee Loans	-	3	3	
6	Employee Withholdings	(15)	(14)	1	
7					
8	**Other Working Capital Items**				
9	Inventories - Materials and Supplies	26	35	9	
10					
11	Total	$ 81	$ 84	$ 3	
12					

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2022 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 1,966	40.3	$ 79,230		
4	Commercial Tariff Revenue	1,983	37.8	74,957		
5	Industrial Tariff Revenue	-	-	-		
6						
7	**Other Revenue**					
8	Late Payment Charges	15	53.8	807		
9	Application Charge	4	39.0	156		
10						
11	Total	$ 3,968		$ 155,150	39.1	
12						
13	**EXPENSES**					
14	Energy Purchases	$ 1,432	(40.0)	$ (57,280)		
15	Operating and Maintenance	820	(31.8)	(26,076)		
16	Property Taxes	159	(1.3)	(207)		
17	Carbon Tax	1,176	(30.7)	(36,103)		
18	GST	39	(39.7)	(1,533)		
19	PST	75	(45.8)	(3,442)		
20	Income Tax	85	(15.2)	(1,292)		
21						
22	Total	$ 3,786		$ (125,933)	(33.3)	
23						
24	Net Lag (Lead) Days				5.8	
25	Total Expenses				$ 3,786	
26						
27	Cash Working Capital				$ 60	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved	2022 Forecast at Existing Rates	2022 Forecast Revised Revenue	2022 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	492	471		471	(21)	
3	Transportation Volume (TJ)	-	-		-	-	
4		492	471	-	471	(21)	Schedule 13, Line 7, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 3,392	$ 3,866	$ -	$ 3,866	$ 474	
8	Deficiency (Surplus)	-		83	83	83	
9	Total	3,392	3,866	83	3,949	557	Schedule 15, Line 13, Column 8
10				-			
11	**COST OF ENERGY**	859	1,432	-	1,432	573	Schedule 14, Line 7, Column 3
12							
13	**MARGIN**	2,533	2,434	83	2,517	(16)	
14							
15	**EXPENSES**						
16	O&M Expense (net)	823	820	-	820	(3)	Schedule 16, Line 21, Column 3
17	Depreciation & Amortization	587	657	-	657	70	Schedule 17, Line 9, Column 3
18	Property Taxes	151	159	-	159	8	Schedule 18, Line 4, Column 3
19	Deferred 2021 Revenue Surplus	132	-	-	-	(132)	Schedule 1, Line 30, Column 3
20	Other Revenue	(14)	(19)	-	(19)	(5)	Schedule 19, Line 4, Column 3
21	Utility Income Before Income Taxes	854	817	83	900	46	
22							
23	Income Taxes	70	63	22	85	15	Schedule 20, Line 13, Column 3
24							
25	**EARNED RETURN**	$ 784	$ 754	$ 61	$ 815	$ 31	Schedule 22, Line 5, Column 7
26							
27	**UTILITY RATE BASE**	$ 12,503	$ 13,182		$ 13,186	$ 683	Schedule 2, Line 24, Column 3
28	**RATE OF RETURN ON UTILITY RATE BASE**	6.27%	5.72%		6.18%	-0.09%	Schedule 22, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 13

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	235.2	233.8	(1.4)	
4	Commercial				
5	Rate Schedule 2	166.9	150.2	(16.7)	
6	Rate Schedule 3	90.2	87.2	(3.0)	
7	Total	492.3	471.2	(21.1)	
8					
9	**REVENUE AT EXISTING RATES**				
10	Residential				
11	Rate Schedule 1	$ 1,631	$ 1,925	$ 294	
12	Commercial				
13	Rate Schedule 2	1,235	1,324	89	
14	Rate Schedule 3	526	617	91	
15	Total	$ 3,392	$ 3,866	$ 474	

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 14

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 411	$ 711	$ 300	
4	Commercial				
5	Rate Schedule 2	291	457	166	
6	Rate Schedule 3	157	264	107	
7	Total	$ 859	$ 1,432	$ 573	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved Margin	2022 Forecast Margin at Existing Rates	2022 Forecast Effective Increase	2022 Forecast Margin at Revised Rates	2022 Forecast Revenue at Existing Rates	2022 Forecast Effective Increase	2022 Forecast Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential										
3	Rate Schedule 1	$ 1,220	$ 1,214	$ 41	$ 1,255	$ 1,925	$ 41	$ 1,966	1,854	233.8	
4	Commercial										
5	Rate Schedule 2	944	867	30	897	1,324	30	1,354	446	150.2	
6	Rate Schedule 3	369	353	12	365	617	12	629	14	87.2	
7	Total Non-Bypass	$ 2,533	$ 2,434	$ 83	$ 2,517	$ 3,866	$ 83	$ 3,949	2,314	471.2	
8											
9											
10	Total Bypass & Special	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	-	
11											
12											
13	Total	$ 2,533	$ 2,434	$ 83	$ 2,517	$ 3,866	$ 83	$ 3,949	2,314	471.2	
14											
15	**Effective Increase**			3.41%			2.15%				

OPERATING AND MAINTENANCE EXPENSE - RESOURCE VIEW
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 16

Line No.	Particulars	2021 Approved	2022 Forecast	Cross Reference
	(1)	(2)	(3)	(4)
1	M&E Costs	$ 18	$ 18	
2	IBEW Costs	242	255	
3				
4	**Labour Costs**	**260**	**273**	
5				
6	Vehicle Costs	26	46	
7	Employee Expenses	12	6	
8	Materials and Supplies	2	19	
9	Fees and Administration Costs	587	576	
10	Contractor Costs	15	36	
11	Facilities	34	26	
12	Recoveries & Revenue	(1)	(6)	
13				
14	**Non-Labour Costs**	**675**	**703**	
15				
16	**Total Gross O&M Expenses**	**935**	**976**	
17				
18	Less: Capitalized Overhead	(112)	(156)	
19				
20				
21	**Total O&M Expenses**	**$ 823**	**$ 820**	Schedule 12, Line 16, Column 5

Schedule 16.1

OPERATING AND MAINTENANCE EXPENSE - ACTIVITY VIEW
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	Account	2021 Approved	2022 Forecast	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Distribution Supervision	110-11	$ 91	$ 102	
2	Distribution Supervision Total	110-10	91	102	
3					
4	Operation Centre - Distribution	110-21	52	61	
5	Preventative Maintenance - Distribution	110-22	16	20	
6	Operations - Distribution	110-23	50	63	
7	Emergency Management - Distribution	110-24	38	46	
8	Field Training - Distribution	110-25	17	24	
9	Meter Exchange - Distribution	110-26	19	18	
10	Distribution Operations Total	110-20	192	232	
11					
12	Corrective - Distribution	110-31	50	53	
13	Distribution Maintenance Total	110-30	50	53	
14					
15	Account Services - Distribution	110-41	9	10	
16	Bad Debt Management - Distribution	110-42	6	2	
17	Distribution Meter to Cash Total	110-40	15	12	
18					
19	**Distribution Total**	**110**	**348**	**399**	
20					
21	**Operations Total**	**100**	**348**	**399**	
22					
23	Administration & General	540-11	-	-	
24	Shared Services Agreement	540-12	587	577	
25	Retiree Benefits	540-16	-	-	
26	Corporate Total	540-10	587	577	
27					
28	**Corporate Total**	**540**	**587**	**577**	
29					
30	**Corporate Services Total**	**500**	**587**	**577**	
31					
32	**Total Gross O&M Expenses**		**935**	**976**	
33					
34	Less: Capitalized Overhead		(112)	(156)	
35					
36	**Total O&M Expenses**		**$ 823**	**$ 820**	Schedule 12, Line 16, Column 5

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 486	$ 486	$ -	Schedule 5, Line 38, Column 7
3					
4	**Amortization**				
5	Rate Base deferrals	$ 130	$ 198	$ 68	Schedule 8, Line 23, Column 6
6	CIAC	(29)	(27)	2	Schedule 6, Line 9, Column 5
7		101	171	70	
8					
9	Total	$ 587	$ 657	$ 70	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 18

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 121	$ 125	$ 4	
2	1% In-Lieu of Municipal Taxes	30	34	4	
3					
4	Total	$ 151	$ 159	$ 8	

Schedule 19

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 14	$ 15	$ 1	
2	Application Charge	-	4	4	
3		-			
4	Total	$ 14	$ 19	$ 5	

Schedule 20

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 784	$ 815	$ 31	Schedule 12, Line 25, Column 5
2	Deduct: Interest on Debt	(363)	(371)	(8)	Schedule 22, Line 1+2, Column 7
3	Adjustments to Taxable Income	(232)	(214)	18	Schedule 20, Line 31
4	Accounting Income After Tax	$ 189	$ 230	$ 41	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 259	$ 315	$ 56	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 70	$ 85	$ 15	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 70	$ 85	$ 15	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 486	$ 486	$ -	Schedule 17, Line 2, Column 3
19	Amortization of Deferred Charges	130	198	68	Schedule 17, Line 5, Column 3
20	Amortization of Debt Issue Expenses	3	3	-	
21	Pension Expense	52	24	(28)	
22	OPEB Expense	20	17	(3)	
23					
24	Deductions:				
25	Capital Cost Allowance	(671)	(710)	(39)	Schedule 21, Line 12, Column 6
26	CIAC Amortization	(29)	(27)	2	Schedule 17, Line 6, Column 3
27	Pension Contributions	(29)	(30)	(1)	
28	OPEB Contributions	(7)	(7)	-	
29	Overheads Capitalized Expensed for Tax Purposes	(56)	(78)	(22)	
30	Removal Costs	(131)	(90)	41	Schedule 8, Line 13, Column 4
31	Total	$ (232)	$ (214)	$ 18	

CAPITAL COST ALLOWANCE Schedule 21
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Class	CCA Rate	12/31/2021 UCC Balance	2022 Additions	UCC Adjustment for AIIP *	2022 CCA	12/31/2022 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,775	$ -	$ -	$ (71)	$ 1,704
2	1(b)	6%	457	27	14	(30)	454
3	2	6%	166	-	-	(10)	156
4	3	5%	9	-	-	-	9
5	8	20%	18	10	5	(7)	21
6	12	100%	-	43	-	(43)	-
7	14.1 (pre 2017)	7%	21	-	-	(1)	20
8	49	8%	3,550	14	7	(287)	3,277
9	50	55%	11	18	9	(21)	8
10	51	6%	2,551	971	486	(240)	3,282
11							
12	Total		$ 8,558	$ 1,083	$ 521	$ (710)	$ 8,931
13							
14	* Note - Accelerated Investment Incentive Property						

RETURN ON CAPITAL Schedule 22
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved Earned Return	2022 Amount	2022 Ratio	2022 Average Embedded Cost	2022 Cost Component	2022 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 360	$ 7,844	59.49%	4.65%	2.77%	$ 365	$ 5	Schedule 23, Line 28&30, Column 5&6&7
2	Short Term Debt	3	265	2.01%	2.31%	0.05%	6	3	
3	Common Equity	421	5,077	38.50%	8.75%	3.37%	444	23	
4									
5	Total	$ 784	$ 13,186	100.00%		6.18%	$ 815	$ 31	
6									
7	Cross Reference		Schedule 2, Line 24, Column 3						

EMBEDDED COST OF LONG TERM DEBT Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Medium Term Note - Series 11	September 21, 1999	September 21, 2029	$ 147,710	$ 150,000	7.073%	$ 10,610	
2	2004 Long Term Debt Issue - Series 18	April 29, 2004	May 1, 2034	148,085	150,000	6.598%	9,897	
3	2005 Long Term Debt Issue - Series 19	February 25, 2005	February 25, 2035	148,337	150,000	5.980%	8,970	
4	2006 Long Term Debt Issue - Series 21	September 25, 2006	September 25, 2036	119,216	120,000	5.595%	6,714	
5	2007 Medium Term Debt Issue - Series 22	October 2, 2007	October 2, 2037	247,697	250,000	6.067%	15,168	
6	2008 Medium Term Debt Issue - Series 23	May 13, 2008	May 13, 2038	247,588	250,000	5.869%	14,673	
7	2009 Med.Term Debt Issue- Series 24	February 24, 2009	February 24, 2039	98,766	100,000	6.645%	6,645	
8	2011 Medium Term Debt Issue - Series 25	December 9, 2011	December 9, 2041	98,590	100,000	4.334%	4,334	
9	2015 Medium Term Debt Issue - Series 26 (Series A Renewal)	April 13, 2015	April 13, 2045	148,938	150,000	3.413%	5,120	
10	2016 Medium Term Debt Issue - Series 27 (Series B Renewal)	April 8, 2016	April 8, 2026	127,704	128,545	2.644%	3,399	
11	2016 Medium Term Debt Issue - Series 28	April 8, 2016	April 9, 2046	148,746	150,000	3.716%	5,574	
12	2016 Medium Term Debt Issue - Series 29	December 13, 2016	March 6, 2047	148,865	150,000	3.822%	5,733	
13	2017 Medium Term Debt Issue - Series 30	October 30, 2017	October 30, 2047	173,584	175,000	3.735%	6,536	
14	2018 Medium Term Debt Issue - Series 31	December 7, 2018	December 7, 2048	198,351	200,000	3.897%	7,794	
15	2019 Medium Term Debt Issue - Series 32	August 9, 2019	August 9, 2049	198,500	200,000	2.857%	5,714	
16	2020 Medium Term Debt Issue - Series 33	July 13, 2020	July 13, 2050	198,392	200,000	2.579%	5,158	
17	2021 Medium Term Debt Issue - Series 34	April 14, 2021	July 18, 2031	149,162	150,000	2.482%	3,723	
18	2022 Medium Term Debt Issue	July 1, 2022	July 1, 2052	198,000	100,822	3.655%	3,685	
19								
20	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
21	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
22								
23	LILO Obligations - Creston	November 1, 2005	October 31, 2022		1,518	8.366%	127	
24								
25	Vehicle Lease Obligation				247	2.024%	5	
26								
27	Sub-Total				$ 3,226,132		$ 150,130	
28	Fort Nelson Division Portion of Long Term Debt				$ 7,844		$ 365	
29								
30	Average Embedded Cost					4.65%		
31								
32	* Interest Rate is Effective interest rate as it includes amortization of debt issue costs							

Appendix E-2

2022 TARIFF CONTINUITY AND BILL IMPACTS

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2022 RATES
BCUC ORDER G-XX-21

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE Particulars	EXISTING RATES JANUARY 1, 2021 Fort Nelson	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson	PROPOSED JANUARY 1, 2022 RATES [1] Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$0.3701**	**$0.0000**	**$0.3701**
3				
4	Delivery Charge per GJ	$4.118	$0.178	$4.296
5	Rider 5 RSAM per GJ	($0.333)	($0.083)	($0.416)
6	Subtotal **Delivery Margin Related Charges per GJ**	**$3.785**	**$0.095**	**$3.880**
7				
8				
9	Commodity Related Charges			
10	Storage and Transport Charge per GJ	$0.043	$0.000	$0.043
11	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$2.999	$0.000	$2.999
12	Subtotal **of Commodity Related Charges per GJ**	**$3.042**	**$0.000**	**$3.042**

[1] The Cost of Gas charge and Storage and Transport charges are approved pursuant to BCUC Order G-312-20 of the FEI Ft. Nelson Service Area 2020 Fourth Quarter Gas Cost Report.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2022 RATES
BCUC ORDER G-XX-21

Line No.	**RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE** Particulars	**EXISTING RATES JANUARY 1, 2021** Fort Nelson	**DELIVERY MARGIN RELATED CHARGES CHANGES** Fort Nelson	**PROPOSED JANUARY 1, 2022 RATES** [1] Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$1.2151**	**$0.0000**	**$1.2151**
3				
4	Delivery Charge per GJ	$4.461	$0.193	$4.654
5	Rider 5 RSAM per GJ	($0.333)	($0.083)	($0.416)
6	Subtotal **Delivery Margin Related Charges per GJ**	**$4.128**	**$0.110**	**$4.238**
7				
8				
9	Commodity Related Charges			
10	Storage and Transport Charge per GJ	$0.043	$0.000	$0.043
11	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$2.999	$0.000	$2.999
12	Subtotal **of Commodity Related Charges per GJ**	**$3.042**	**$0.000**	**$3.042**

[1] The Cost of Gas charge and Storage and Transport charges are approved pursuant to BCUC Order G-312-20 of the FEI Ft. Nelson Service Area 2020 Fourth Quarter Gas Cost Report.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2022 RATES
BCUC ORDER G-XX-21

Line No.	**RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE** Particulars	**EXISTING RATES JANUARY 1, 2021** Fort Nelson	**DELIVERY MARGIN RELATED CHARGES CHANGES** Fort Nelson	**PROPOSED JANUARY 1, 2022 RATES** [1] Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$3.6845**	**$0.0000**	**$3.6845**
3				
4	Delivery Charge per GJ	$3.839	$0.131	$3.970
5	Rider 5 RSAM per GJ	($0.333)	($0.083)	($0.416)
6	Subtotal **Delivery Margin Related Charges per GJ**	**$3.506**	**$0.048**	**$3.554**
7				
8				
9	Commodity Related Charges			
10	Storage and Transport Charge per GJ	$0.036	$0.000	$0.036
11	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$2.999	$0.000	$2.999
12	Subtotal **of Commodity Related Charges per GJ**	**$3.035**	**$0.000**	**$3.035**

[1] The Cost of Gas charge and Storage and Transport charges are approved pursuant to BCUC Order G-312-20 of the FEI Ft. Nelson Service Area 2020 Fourth Quarter Gas Cost Report.

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	EXISTING RATES JANUARY 1, 2021 Fort Nelson	DELIVERY MARGIN RELATED CHARGES CHANGES Fort Nelson	PROPOSED JANUARY 1, 2022 RATES [1] Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Month**	$600.00	$0.00	$600.00
3				
4	**Demand Charge per Month per GJ**	$34.654	$1.238	$35.892
5				
6	**Delivery Charge per GJ**	$1.148	$0.041	$1.189
7	Subtotal **Delivery Margin Related Charges per GJ**	**$1.148**	**$0.041**	**$1.189**
8				
9	Commodity Related Charges			
10	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$2.999	$0.000	$2.999
11	Storage and Transport Charge per GJ	$0.026	$0.000	$0.026
12	Subtotal **of Commodity Related Charges per GJ**	**$3.025**	**$0.000**	**$3.025**
13				
14				
15				
16				
17	Total Variable Cost per gigajoule	$4.173	$0.041	$4.214

[1] The Cost of Gas charge and Storage and Transport charges are approved pursuant to BCUC Order G-312-20 of the FEI Ft. Nelson Service Area 2020 Fourth Quarter Gas Cost Report.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2022 RATES
BCUC ORDER G-XX-21

Line No.	RATE SCHEDULE 6: NATURAL GAS VEHICLE SERVICE	EXISTING RATES JANUARY 1, 2021	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2022 RATES [1]
	Particulars	**Fort Nelson**	**Fort Nelson**	**Fort Nelson**
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	$2.0041	$0.0000	$2.0041
3	**Delivery Charge per GJ**	$2.992	$0.214	$3.206
4				
5				
6	Commodity Related Charges			
7	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$2.999	$0.000	$2.999
8	Storage and Transport Charge per GJ	$0.013	$0.000	$0.013
9	Subtotal **of Commodity Related Charges per GJ**	**$3.012**	**$0.000**	**$3.012**
10				
11				
12				
13				
14	Total Variable Cost per gigajoule	$6.004	$0.214	$6.218

[1] The Cost of Gas charge and Storage and Transport charges are approved pursuant to BCUC Order G-312-20 of the FEI Ft. Nelson Service Area 2020 Fourth Quarter Gas Cost Report.

	RATE SCHEDULE 25 **GENERAL FIRM TRANSPORTATION SERVICE**	**EXISTING RATES JANUARY 1, 2021**	**DELIVERY MARGIN** **RELATED CHARGES CHANGES**	**PROPOSED JANUARY 1, 2022**
Line No.	Particulars	**Fort Nelson**	**Fort Nelson**	**Fort Nelson**
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Month**	$600.00	$0.00	$600.00
3				
4	**Demand Charge per Month per GJ**	$34.654	$1.238	$35.892
5				
6	**Delivery Charge per GJ**	$1.148	$0.041	$1.189
7				
8	**Administration Charge per Month**	$39.00	$0.00	$39.00
9				
11				
12	**Non-Standard Charges**			
13	**Unauthorized Overrun Gas Charges**			
14	Per Gigajoule on first 5 percent of specified quantity	Station 2 Daily Price	$0.00	Station 2 Daily Price
15				
16	Per Gigajoule on all Gas over 5 percent of specified quantity	The greater of $20.00/GJ or 1.5 x the Station 2 Daily Price	$0.00	The greater of $20.00/GJ or 1.5 x the Station 2 Daily Price
17				
18	**Charge per Gigajoule of Balancing Service provided**			
19	Quantities of Gas less than 10% of the Rate Schedule 25			
20	Authorized Quantity	No charge	$0.00	No charge
21	Quantities of Gas over the greater of 100 Gigajoules or equal to			
22	or in excess of 10% or less than 20% of the Rate Schedule 25			
23	Authorized Quantity	$0.25	$0.00	$0.25
24	Quantities of Gas over the greater of 100 Gigajoules or equal to			
25	or in excess of 20% of the Rate Schedule 25 Authorized			
26	Quantity			
27	(i) between and including April 1 and Oct 31	$0.30	$0.00	$0.30
28	(ii) between and including Nov 1 and March 31	$1.10	$0.00	$1.10
29				
30				
31	**Charge per Gigajoule of Balancing and/or Backstopping Gas**	Station 2 Daily Price	$0.00	Station 2 Daily Price
32				
33				
34				
35				
36	Total Variable Cost per gigajoule	$1.148	$0.041	$1.189

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER G-XX-21
RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2021						PROPOSED JANUARY 1, 2022 RATES						Annual Increase/Decrease		
1	**FORT NELSON SERVICE AREA**	Quantity		Rate		Annual $		Quantity		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
2	Delivery Margin Related Charges															
3	Basic Charge per Day	365.25	days x	$0.3701	=	$135.18		365.25	days x	$0.3701	=	$135.18		$0.0000	$0.00	0.00%
4																
5	Delivery Charge per GJ	125.0	GJ x	$4.118	=	514.7500		125.0	GJ x	$4.296	=	537.0000		$0.178	22.2500	2.25%
6	Rider 5 RSAM per GJ	125.0	GJ x	($0.333)	=	(41.6250)		125.0	GJ x	($0.416)	=	(52.0000)		($0.083)	(10.3750)	-1.05%
7	Subtotal Delivery Margin Related Charges					**$608.31**						**$620.18**			**$11.87**	**1.20%**
8																
9	Commodity Related Charges															
10	Storage and Transport Charge per GJ	125.0	GJ x	$0.043	=	$5.38		125.0	GJ x	$0.043	=	$5.38		$0.000	$0.00	0.00%
11																
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	125.0	GJ x	$2.999	=	$374.88		125.0	GJ x	$2.999	=	$374.88		$0.000	$0.00	0.00%
13	Subtotal Commodity Related Charges					**$380.26**						**$380.26**			**$0.00**	**0.00%**
14																
15	Total *(with effective $/GJ rate)*	125.0		*$7.909*		**$988.57**		125.0		*$8.004*		**$1,000.44**		*$0.095*	**$11.87**	**1.20%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER G-XX-21

RATE SCHEDULE 2 - SMALL COMMERCIAL SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2021						PROPOSED JANUARY 1, 2022 RATES						Annual Increase/Decrease		
		Quantity			Rate		Annual $	Quantity			Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FORT NELSON SERVICE AREA**															
2	Delivery Margin Related Charges															
3	Basic Charge per Day	365.25	days	x	$1.2151	=	$443.82	365.25	days	x	$1.2151	=	$443.82	$0.0000	$0.00	0.00%
4																
5	Delivery Charge per GJ	335.0	GJ	x	$4.461	=	1,494.4350	335.0	GJ	x	$4.654	=	1,559.0900	$0.193	64.6550	2.27%
6	Rider 5 RSAM per GJ	335.0	GJ	x	($0.333)	=	(111.5550)	335.0	GJ	x	($0.416)	=	(139.3600)	($0.083)	(27.8050)	-0.98%
7	Subtotal Delivery Margin Related Charges						**$1,826.70**						**$1,863.55**		**$36.85**	**1.29%**
8																
9	Commodity Related Charges															
10	Storage and Transport Charge per GJ	335.0	GJ	x	$0.043	=	$14.41	335.0	GJ	x	$0.043	=	$14.41	$0.000	$0.00	0.00%
11																
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	335.0	GJ	x	$2.999	=	$1,004.67	335.0	GJ	x	$2.999	=	$1,004.67	$0.000	$0.00	0.00%
13	Subtotal Commodity Related Charges						**$1,019.08**						**$1,019.08**		**$0.00**	**0.00%**
14																
15	Total *(with effective $/GJ rate)*	335.0			*$8.495*		**$2,845.78**	335.0			*$8.605*		**$2,882.63**	*$0.110*	**$36.85**	**1.29%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER G-XX-21
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2021						PROPOSED JANUARY 1, 2022 RATES						Annual Increase/Decrease		
1	**FORT NELSON SERVICE AREA**	Quantity		Rate		Annual $		Quantity		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
2	Delivery Margin Related Charges															
3	Basic Charge per Day	365.25	days x	$3.6845	=	$1,345.76		365.25	days x	$3.6845	=	$1,345.76		$0.0000	$0.00	0.00%
4																
5	Delivery Charge per GJ	6,375.0	GJ x	$3.839	=	24,473.6250		6,375.0	GJ x	$3.970	=	25,308.7500		$0.131	835.1250	1.94%
6	Rider 5 RSAM per GJ	6,375.0	GJ x	($0.333)	=	(2,122.8750)		6,375.0	GJ x	($0.416)	=	(2,652.0000)		($0.083)	(529.1250)	-1.23%
7	Subtotal Delivery Margin Related Charges					**$23,696.51**						**$24,002.51**			**$306.00**	**0.71%**
8																
9	Commodity Related Charges															
10	Storage and Transport Charge per GJ	6,375.0	GJ x	$0.036	=	$229.50		6,375.0	GJ x	$0.036	=	$229.50		$0.000	$0.00	0.00%
11																
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	6,375.0	GJ x	$2.999	=	$19,118.63		6,375.0	GJ x	$2.999	=	$19,118.63		$0.000	$0.00	0.00%
13	Subtotal Commodity Related Charges					**$19,348.13**						**$19,348.13**			**$0.00**	**0.00%**
14																
15	Total *(with effective $/GJ rate)*	6,375.0		*$6.752*		**$43,044.64**		6,375.0		*$6.800*		**$43,350.64**		*$0.048*	**$306.00**	**0.71%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding

Appendix F

DRAFT ORDERS

Appendix F-1

DRAFT PROCEDURAL ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
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F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for Fort Nelson Service Area Common Rates and 2022 Revenue Requirements

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On August 12, 2021, FortisBC Energy Inc. (FEI) submitted an Application to the British Columbia Utilities Commission (BCUC) pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA), to implement common delivery and cost of gas rates for the Fort Nelson Service Area (FEFN) with FEI effective January 1, 2023 and to set the delivery rates and the Revenue Stabilization Adjustment Mechanism (RSAM) rate rider for FEFN effective January 1, 2022 (Application);

B. In the Application, FEI requests approval of the following:

1. Approval to recover the 2022 revenue requirement, as set out in Section 8 of the Application, through an effective delivery rate increase of 3.41 percent, on a permanent basis, effective January 1, 2022;

2. The RSAM rate rider to be set to a credit of $0.416 per gigajoule (GJ), as set out in Section 8.2, Table 8-2, effective January 1, 2022;

3. Adoption of the following common accounting policies for FEFN which were approved for FEI by Order G-165-20:

    i. Capitalized overhead rate of 16 percent;

    ii. Depreciation and net salvage rates as set out in FEI's most recently approved depreciation study; and

    iii. Modification to the lead/lag days, as set out in FEI's most recently approved lead/lag study, for calculation of FEFN's cash working capital;

4. Amalgamation of FEFN's gas supply portfolio costs with FEI's Midstream Cost Reconciliation Account (MCRA), as described in in Section 5.3.5;

5. Implementation of common delivery rates for FEFN with FEI, effective January 1, 2023, as described in Sections 5.5 and 7 of the Application; and

6. Approval to establish a new rate base deferral account, the FEFN Common Rates and 2022 Revenue Requirement Application Costs deferral account, to capture the regulatory costs associated with this Application and corresponding regulatory process;

C. FEI submits that a decision on 2022 delivery rates is unlikely to be received prior to January 1, 2022 and therefore requests approval pursuant to sections 59 to 61 and 89 of the UCA of the proposed effective delivery rate increase of 3.41 percent on an interim and refundable basis, and approval to set the RSAM rider to a credit of $0.416 per GJ, both effective January 1, 2022 for FEFN; and

D. The BCUC considers that establishment of a regulatory timetable for the review of the Application and approval of interim delivery rates is warranted.

NOW THEREFORE pursuant to sections 59 to 61 and 89 of the UCA, the BCUC orders as follows:

1. An effective delivery rate increase of 3.41 percent on an interim and refundable basis and an RSAM rider set at a credit of $0.416 per GJ are approved for the Fort Nelson Service Area effective January 1, 2022.

2. A regulatory timetable for the review of the Application is established, as set out in Appendix A to this order.

3. By no later than September 17, 2021, FEI is to publish the Public Notice, attached as Appendix B to this Order, in such local and community newspapers as to provide adequate notice to those parties who may have an interest in or be affected by the Application.

4. Interveners are to register with the BCUC by completing a Request to Intervene form, available on the BCUC website, by the date established in the regulatory timetable attached as Appendix A to this order, and in accordance with the BCUC's Rules of Practice and Procedure attached to Order G-15-19.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment

FortisBC Energy Inc.
Application for Fort Nelson Service Area Common Rates and 2022 Revenue Requirements

REGULATORY TIMETABLE

ACTION	DATE
BCUC Issues Procedural Order	Week of August 30, 2021
FEI Publishes Notice by	Week of September 13, 2021
Intervener Registration	Thursday, September 30, 2021
BCUC Information Request (IR) No. 1 on 2022 Delivery Rates and Common Rates	Thursday, October 7, 2021
Intervener IR No. 1 on 2022 Delivery Rates and Common Rates	Friday, October 15, 2021
FEI Response to IR No. 1 on 2022 Delivery Rates and Common Rates	Friday, November 5, 2021
Commencement of Separate Review Streams for the 2022 Delivery Rate Component and the Common Rates Component	
FEI Final Argument on 2022 Delivery Rates	Monday, November 15, 2021
Intervener Final Argument on 2022 Delivery Rates	Monday, November 29, 2021
BCUC and Intervener IR No. 2 on Common Rates	Wednesday, December 1, 2021
FEI Reply Argument on 2022 Delivery Rates	Monday, December 13, 2021
FEI Response to IR No. 2 on Common Rates	Wednesday, December 22, 2021
FEI Final Argument on Common Rates	Friday, January 7, 2022
Intervener Final Argument on Common Rates	Friday, January 21, 2022
FEI Reply Argument on Common Rates	Friday, February 4, 2022

bcuc
British Columbia
Utilities Commission

PUBLIC NOTICE

FortisBC Energy Inc.
Application for Fort Nelson Service Area Common Rates and 2022 Revenue Requirements

On August 12, 2021, FortisBC Energy Inc. applied to the British Columbia Utilities Commission (BCUC) for approval to implement common delivery and cost of gas rates for the Fort Nelson Service Area (FEFN) with FEI effective January 1, 2023 and to set the delivery rates and the Revenue Stabilization Adjustment Mechanism (RSAM) rate rider for FEFN effective January 1, 2022.

More information on the application can be found at **bcuc.com** on our "Current Proceedings" page, a hard copy of the application is also available for review at the BCUC's office and FEI's head office.

HOW TO PARTICIPATE

- **Submit a letter of comment**
- **Register as an intervener**

IMPORTANT DATES

1. **[day, date]** – Deadline to register as an intervener or file a letter of comment with the BCUC.

For more information on how to participate, please visit our website (**www.bcuc.com/get-involved**) or contact us at the information below.

All submissions will be added to the public record and posted on the BCUC's website.

GET MORE INFORMATION

FortisBC Energy Inc. Regulatory Affairs

16705 Fraser Highway
Surrey, BC Canada V4N 0E8

E: gas.regulatory.affairs@fortisbc.com

P: 604.592.7664

British Columbia Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3

E: Commission.Secretary@bcuc.com

P: 604.660.4700

Appendix F-2

DRAFT FINAL ORDER – 2022 DELIVERY RATES

bcuc
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Utilities Commission

Suite 410, 900 Howe Street
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P: 604.660.4700
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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for Fort Nelson Service Area Common Rates and 2022 Revenue Requirements

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On August 12, 2021, FortisBC Energy Inc. (FEI) submitted an Application to the British Columbia Utilities Commission (BCUC) pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA), to implement common delivery and cost of gas rates for the Fort Nelson Service Area (FEFN) with FEI effective January 1, 2023 and to set the delivery rates and the Revenue Stabilization Adjustment Mechanism (RSAM) rate rider for FEFN effective January 1, 2022 (Application);

B. FEI requests approval of the following with regard to the 2022 revenue requirement and delivery rates for for the Fort Nelson Service Area:

1. Approval to recover the 2022 revenue requirement, as set out in Section 8 of the Application, through an effective delivery rate increase of 3.41 percent, on a permanent basis, effective January 1, 2022;

2. The RSAM rider to be set to a credit of $0.416 per gigajoule (GJ), as set out in Section 8.2, Table 8-2, effective January 1, 2022;

3. Adoption of the following common accounting policies for FEFN which were approved for FEI by Order G-165-20:

    i. Capitalized overhead rate of 16 percent;

    ii. Depreciation and net salvage rates as set out in FEI's most recently approved depreciation study; and

iii. Modification to the lead/lag days, as set out in FEI's most recently approved lead/lag study, for calculation of FEFN's cash working capital; and

4. Approval of the creation of a new rate base deferral account, the FEFN Common Rates and 2022 Revenue Requirement Application Costs deferral account, to capture the regulatory costs associated with this Application and corresponding regulatory process;

C. By Order G-XXX-21 dated XX, the BCUC established a regulatory timetable for the review of the 2022 revenue requirement and delivery rates component of the Application, which included intervener registration, one round of information requests, and written arguments. The BCUC also approved an effective delivery rate increase of 3.41 percent on an interim and refundable basis and an RSAM rider credit of $0.416 per GJ for FEFN, effective January 1, 2022; and

D. The BCUC considers that the following determinations are warranted.

NOW THEREFORE pursuant to sections 59 to 61 of the UCA, the BCUC orders as follows:

1. FEI is approved to recover the 2022 revenue requirement, as set out in Section 8 of the Application, through an effective delivery rate increase of 3.41 percent, on a permanent basis, effective January 1, 2022.

2. FEI is approved to adopt the following common accounting policies for FEFN which were approved for FEI by Order G-165-20:

    a. Capitalized overhead rate of 16 percent;

    b. Depreciation and net salvage rates as set out in FEI's most recently approved depreciation study; and

    c. Modification to the lead/lag days, as set out in FEI's most recently approved lead/lag study, for calculation of FEFN's cash working capital.

3. FEI is approved to establish a new rate base deferral account, the FEFN Common Rates and 2022 Revenue Requirement Application Costs deferral account, to capture the regulatory costs associated with this Application and corresponding regulatory process.

4. FEI is directed to file with the BCUC, within 30 days of the issuance of this order, amended tariff pages for 2022 permanent delivery rates in accordance with the terms of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Appendix F-3

DRAFT FINAL ORDER – FEFN COMMON RATES

bcuc
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Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for Fort Nelson Service Area Common Rates and 2022 Revenue Requirements

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On August 12, 2021, FortisBC Energy Inc. (FEI) submitted an Application to the British Columbia Utilities Commission (BCUC) pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA), to implement common delivery and cost of gas rates for the Fort Nelson Service Area (FEFN) with FEI effective January 1, 2023 and to set the delivery rates and the Revenue Stabilization Adjustment Mechanism (RSAM) rate rider for FEFN effective January 1, 2022 (Application);

B. In the Application, FEI requests approval of the following with regard to implementing common delivery and cost of gas rates for FEFN with FEI, effective January 1, 2023:

   1. Amalgamation of FEFN's gas supply portfolio costs with FEI's Midstream Cost Reconciliation Account (MCRA) as described in Section 5.3.5; and

   2. Implementation of common delivery rates for FEFN with FEI, as described in Sections 5.5 and 7;

C. By Order G-XXX-21 dated XX, the BCUC established a regulatory timetable for the review of the common rates component of the Application, which included intervener registration, two rounds of information requests, and written arguments; and

D. The BCUC considers that the following determinations are warranted.

NOW THEREFORE pursuant to sections 59 to 61 of the UCA, the BCUC orders as follows:

1. FEI is approved to amalgamate FEFN's gas supply portfolio costs with FEI's Midstream Cost Reconciliation Account (MCRA) as follows:

a. Transfer the closing December 31, 2022 balance of FEFN's Gas Cost Reconciliation Account (GCRA) to FEI's MCRA as an opening balance adjustment, effective January 1, 2023;

b. Eliminate FEFN's GCRA;

c. Starting January 1, 2023, capture all of FEFN's natural gas supply portfolio costs, including FEFN's transportation costs, in FEI's MCRA;

d. Starting January 1, 2023, charge FEFN customers the same cost of gas rate as FEI customers, with the recoveries of the cost of gas rate from FEFN's customers captured in FEI's MCRA; and

e. Starting January 1, 2023, set FEFN's midstream rates based on 5 percent of FEI's midstream rates.

2. FEI is approved to implement common delivery rates for FEFN with FEI, effective January 1, 2023 as follows:

   a. Transfer the closing December 31, 2022 balances of FEFN's gross plant in service, accumulated depreciation, contributions in aid of construction (CIAC), and accumulated amortization of CIAC to FEI's corresponding plant accounts and include these amounts in FEI's rate base as January 1, 2023 opening balance adjustments;

   b. Approval of the treatment of each of FEFN's deferral accounts as described in Table 7-1 in Section 7.1.4.1 and Section 7.1.4.2;

   c. Transfer FEFN's capital work in progress (no AFUDC) and unamortized deferred charges to FEI's rate base under the same categories;

   d. Include FEFN's operations and maintenance (O&M) expenses in FEI's formula O&M effective January 1, 2023 by adding FEFN's forecast 2023 customer count to FEI's forecast 2023 customer count, with these changes to be forecast in FEI's Annual Review for 2023 Delivery Rates;

   e. Incorporate FEFN's annual forecast capital expenditures into FEI's regular forecast capital expenditures commencing January 1, 2023, with these changes to be forecast in FEI's Annual Review for 2023 Delivery Rates;

   f. Approval of certain amendments to the FEI Tariff Rate Schedules, including the proposed FEFN rate schedule mapping to the applicable FEI rate schedules, as described in Section 7.1.5 and set out in Appendix D, effective January 1, 2023;

   g. Approval of the cancellation of the FEFN Gas Tariff, including the FEFN rate schedules and rates, as described in Section 7.1.5, effective January 1, 2023; and

   h. Phase in common delivery rates for the FEFN residential customer rate class (Rate Schedule 1) over 10 years through the creation of a Residential Customer Phase-in Rate Rider, effective January 1, 2023, to mitigate the initial delivery rate impact to FEFN residential customers resulting from common rates with FEI, as described in Sections 5.5 and 7.1.4.4. The approval of the phase-in rate rider is comprised of:

      i. Setting the phase-in rate rider by phasing in the initial delivery rate impact to FEFN residential customers over 10 years and phasing in the approved 2021 FEFN revenue surplus, with a forecast credit balance of $94 thousand at December 31, 2022, over 10 years;

ii. Renaming the existing FEFN 2021 Revenue Surplus deferral account to the FEFN Residential Common Rate Phase-in deferral account, and using this deferral account for the purposes of phasing in common delivery rates for FEFN residential customers; and

iii. Setting the actual phase-in rate rider each year in FEI's annual reviews based on updated forecasts of FEFN's residential customer demand and the balance of the deferral account each year for the 10-year period.

3. FEI is directed to file with the BCUC, within 30 days of the implementation of common rates effective January 1, 2023, amended tariff pages in accordance with the terms of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner