Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
www.fortisbc.com

October 20, 2022

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

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

Re: British Columbia Utilities Commission (BCUC) 2022 Generic Cost of Capital (GCOC) Proceeding – Stage 1

Evidence of FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC)

Errata on FortisBC's Business Risk Evidence, dated October 20, 2022

On January 31, 2022, FortisBC filed its Evidence in the above referenced proceeding in accordance with BCUC Order G-281-21. In the process of responding to the information requests (IRs) and preparations for the oral hearing, FortisBC identified a number of corrections required to the tables and figures, and one footnote reference, in its Business Risk Evidence. FortisBC is filing these revisions to ensure an accurate record for the upcoming oral hearing, although none of the revisions are of a material nature.

FortisBC respectfully files the attached Errata, which includes the following items:

Description	Revised Pages/ Figures/ Tables	Referenced IR
Exhibit B1-8-1 – Appendix A – FEI Business Risk Assessment	Page 9, Table A2-1	BCOAPO IR1 3.1
	Page 45, Footnote 74	N/A
	Page 73, Line 3 and Figure A6-17	BCOAPO IR1 7.7.2
	Page 89, Lines 6-7	BCOAPO IR1 8.6
Exhibit B1-8-1 – Appendix B – FBC Business Risk Assessment	Page 11, Line 15 and Figure B2-1	BCOAPO IR1 11.4
	Pages 21 to 22, Line 12 and Figure B6-3	N/A
	Pages 30 to 31, Line 14, Figures B7-1 and B7-2	BCUC IR1 1 33.6

A summary description of each item is further discussed below:

FEI's Business Risk Evidence (Appendix A)

- Page 9, Table A2-1: As noted in the response to BCOAPO IR1 3.1, on page 9 of FEI's business risk evidence and in the Table A2-1, for 2022, the percent of sales revenue for the commercial sector has been revised to 30 from 27.

- Page 45, Footnote 74: The notes provided in footnote 74 were not related to the referenced sentence and have therefore been replaced with the relevant link.

- Page 73, Line 3 and Figure A6-17: As noted in the response to BCOAPO IR1 7.7.2, FEI identified an error in Figure A6-17 which has now been corrected. As a consequence of the revision to Figure A6-17, line 3 of page 73 stating the percent increase in FEI's total cost per GJ has been revised from 400 percent to 260 percent.

- Page 89, Lines 6-7 regarding Figure A7-6: As noted in the response to BCOAPO IR1 8.6, the term "single family dwellings" describing Figure A7-6 has been replaced with the term "residential customers".

FBC's Business Risk Evidence (Appendix B)

- Page 11, Line 15 and Figure B2-1: As noted in the response to BCOAPO IR1 11.4, Figure B2-1 and line 15 on page 11 have now been updated.

- Pages 21 to 22, Line 12 and Figure B6-3: FBC identified an error in Figure B6-3. As a result of correcting this error, Figure B6-3 and the percentage quoted on line 12 of page 21 have been updated. These changes now indicate that an FBC residential customer electricity bill was 27 percent higher than a BC Hydro residential customer electricity bill at January 1, 2022 (not 19 percent as previously stated).

- Pages 30 to 31, Line 14 and Figures B7-1 and B7-2: As noted in the response to BCUC IR1 33.6, FBC identified that a correction to Figures B7-1 and B7-2 was needed. Line 14 has also been corrected to reference the revised percentages.

Attached are black-lined and clean versions, where appropriate, of the above sections to help parties identify the changes made to the Business Risk Evidence as a result of this errata. None of the errata affect FortisBC's conclusions or recommendations in its evidence.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of FORTISBC

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners

Attachment 1

ERRATA DATED OCTOBER 20, 2022 – BLACKLINED PAGES

Table A2-1: FEI's Business Profile[6]

	2015[7]	2022[8]
Type of Utility	Local Distribution Company (LDC)	
Energy Product Offering	Natural gas, biomethane, propane	
Service Area	Mainland, Vancouver Island, and Whistler	
Rate Base ($000s)	3,661,370	5,409,207
Sales/Transportation Volumes (TJ)	176,035	234,057
Average Number of Customers	970,389	1,068,458
Customer Profile by Demand		
Residential	42%	41%
Commercial	32%	29%
Industrial	26%	31%
Customer Profile by Sales Revenue		
Residential	60%	57%
Commercial	33%	30%
Industrial	7%	12%

Deleted: 27

Overall, FEI assesses that the risk related to the type and size of its gas utility is similar to the 2016 Proceeding. FEI remains a relatively large natural gas distribution utility and although the risk of this type of utility has increased, this risk is covered off under other sections. Further, although rate base has increased by almost 50 percent since 2015, growth in demand and customers has not kept pace. There is some greater diversification of demand paired with a shift to more volatile market segments.

2.2 *FEI'S SERVICE AREA CONCENTRATED IN LOWER MAINLAND*

FEI's business profile risk is further impacted by its regional consumption profile. Figure A2-1 below provides FEI's business profile by region. As can be seen, the majority of FEI's volume, revenue and customers are in the Lower Mainland region followed by the Inland and Vancouver Island regions. The significant share of Lower Mainland consumption in FEI's profile is a risk factor since, as discussed in Section 4.2.3 in the context of Political risk, many of the municipalities

[6] This table excludes data for the Fort Nelson service area. Fort Nelson's 2021 Approved rate base is $12,503 thousand.
[7] Numbers from FEI's Annual Review for 2015 rates.
[8] Numbers from FEI's Annual Review for 2022 Rates:
- Residential includes Rate Schedule 1. Commercial includes Rate Schedules 2, 3, 23.
- Industrial includes Rate Schedules 4, 5, 6, 7, 22, 25, 27, 46.
- With the exception of the rate base amount, all the numbers are for non-bypass customers only. Bypass Transportation volume equals 33,112 TJs and Revenue equals $21,884 thousand.

Errata dated October 20, 2022

accommodation, involvement in decision-making and seeking and obtaining consent. These changes are described in detail below.

5.2 *SIGNIFICANT LEGISLATIVE AND POLICY DEVELOPMENTS SINCE 2016*

There have been significant legislative and policy developments in this area since the 2016 Proceeding, described below, that have broad impacts on FEI's business.

5.2.1 BC Has Passed Legislation to Give Effect to the UN Declaration of the Rights of Indigenous Peoples

In November of 2019, the province passed into law the *Declaration on the Rights of Indigenous Peoples Act* (DRIPA)[68] and in June 2021, the federal *United Nations Declaration on the Rights of Indigenous Peoples Act* (UNDRIP Act) became law. DRIPA and the UNDRIP Act, provide for BC and Canada's laws (respectively) to be brought into alignment with the UN Declaration on the Rights of Indigenous Peoples (Declaration)[69] and the development of action plans to meet the objectives of the Declaration.[70]

BC released its draft action plan in June 2021 which identifies actions for 2021-2026 including co-developing other agreements (whether modern treaties, self-government agreements or others); co-developing strategic-level policies reflecting collaboration and cooperation on stewardship of the environment, land and resources; and engaging First Nations to identify and support clean energy opportunities related to the BCUC Inquiry on the Regulation of Indigenous Utilities.[71]

At this point, the federal action plan has not been developed and the priorities for that plan are unknown. However, the legislative review and action plans of both governments may result in amendments to provincial and federal legislation or policy which may impact FEI's operations.

DRIPA also empowers the provincial government to enter into decision-making agreements with Indigenous groups. Such agreements could require the exercise of statutory power of decision jointly by an Indigenous governing body and the BC government or the consent of an Indigenous governing body before the exercise of a statutory power of decision.[72] The draft BC action plan identifies entering into such decision-making agreements and seeking all necessary legislative amendments to enable the implementation of such agreements to be one of the focuses for the years 2021-2026.[73] BC is in the process of negotiating its first DRIPA consent-based decision-making agreement for the environmental assessment processes for two mining projects.[74] The

---

68 S.B.C. 2019, c. 44 (*DRIPA*).
69 UNDRIP_E_web.pdf.
70 DRIPA, ss. 3 snd 4.
71 Declaration_Act_-_Draft_Action_Plan_for_consultation.pdf (gov.bc.ca).
72 DRIPA, s. 6.
73 Declaration_Act_-_Draft_Action_Plan_for_consultation.pdf (gov.bc.ca).
74 https://news.gov.bc.ca/releases/2022PREM0034-000899.

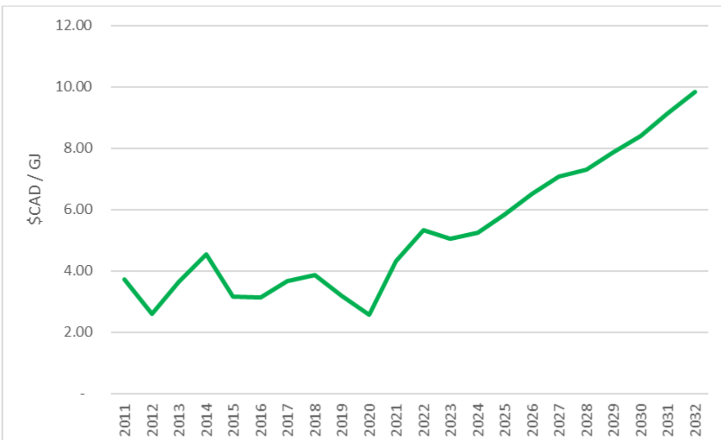
Deleted: BC CPI (all items) from Statistics Canada CANSIM Table 18-10-0004-01.

Errata dated October 20, 2022

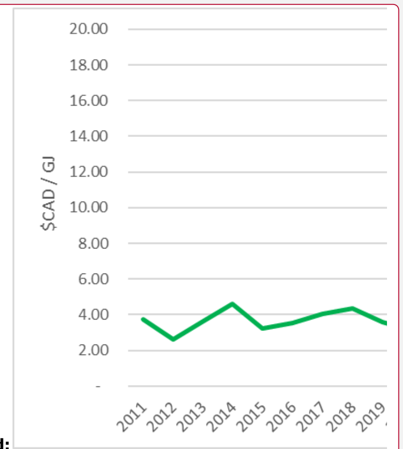
Summing the total cost of the blended gas supply and dividing it by the volume produces the cost of gas per GJ in Figure A6-17 below. Increasing the volume of Renewable Gas within FEI's supply mix, combined with Renewable Gas' higher unit cost, will result in an approximate 260 percent increase in FEI's total cost per GJ by 2032. FEI expects that by 2032, approximately 11 percent of the gaseous energy delivered to customers will be Renewable Gas, resulting in an incremental annual cost of approximately $330 for a residential customer consuming 83 GJs per year.

Deleted: 400

Figure A6-17: Weighted Average Cost of Gas (Renewable and Natural)



Deleted:



Decarbonizing FEI's gas supply in response to climate policy will cause the average cost of energy to increase (Figure A6-17). This rising cost of energy, regardless of specific cost recovery mechanisms or tariffs, will continue to be borne by FEI's customers, reducing FEI's price competitiveness when compared to other energy alternatives. This necessary growth in supply, at a level that was not supported or projected at the time of the 2016 Proceeding, increases FEI's energy price risk.

6.3.4 Price Competitiveness Based on Total Cost Has Decreased since 2015

Section 6.3.1 provided an overview of natural gas price competitiveness on the basis of average annual bill amounts. In this section, price competitiveness will be analyzed by also considering the upfront capital cost differences between gas and electricity end-use applications (space and water heating) for new construction, including the adoption of new technologies which support the use of electricity. In addition to capital costs, efficiency rates and maintenance costs affect the total cost of the appliance over its measure life. Gas appliances have typically higher capital and

determined by multiplying the Renewable Gas volume from Figure A6-16 above by FEI's Renewable Gas per GJ from FEI's Renewable Gas Application filed December 17, 2021. The total natural gas cost is determined by multiplying the natural gas volume as described herewith by the cost of natural gas from Figure A6-16 above.

Errata dated October 20, 2022

Table A7-4 below summarizes the main space heating fuel used by FEI's residential customers. The REUS indicates that, compared to the 2012 REUS that was incorporated in the 2016 Proceeding, the use of natural gas as a main space heating fuel is still diminishing.

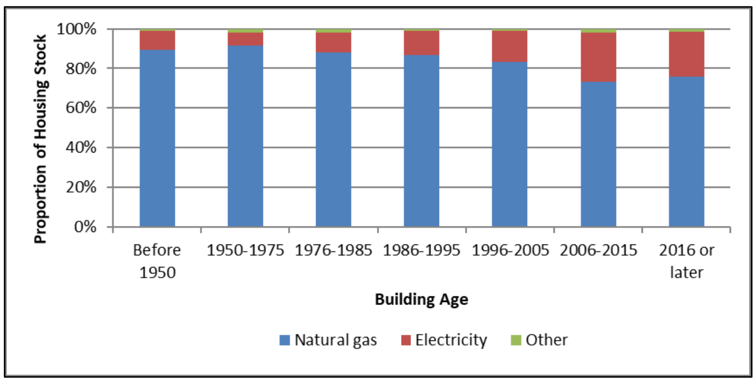
Table A7-4: Space Heating End-use by Fuel Type in FEI's Service Territory

Fuel Type	REUS Year		
	2008	2012	2017
Electricity	7%	11%	12%
Natural Gas	91%	87%	86%
Other	2%	2%	2%

Figure A7-6 below illustrates the main space heating fuel trend by dwelling age for residential customers.

Deleted: single-family dwellings

Figure A7-6: Natural Gas Use for Residential Space Heating by Building Vintage



Source: 2017 Residential End-use study

The REUS report provides the following comments on the above trend:

> Of note, the relative share of dwellings using natural gas as their main space heating fuel began declining in the 1990s. For example, 87% of homes constructed between 1986 and 1995 use natural gas as the main space heating fuel compared to 73% of homes constructed between 2006 and 2015. In its place, electricity is now the main space heating fuel for approximately one-quarter (25%) of all dwellings constructed since 2006. The shift from natural gas to electricity reflects, in part, increased penetration of air source heat pumps and electric baseboards in newer dwellings. The slight increase in gas share for homes built since 2015 is not statistically significant at the 95% confidence level.

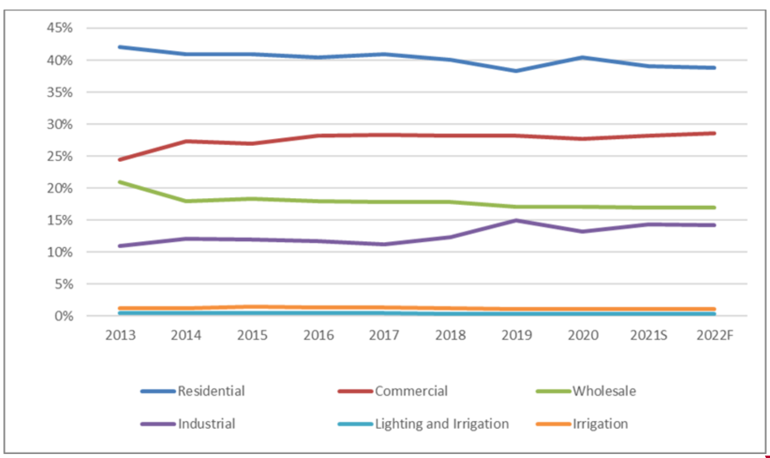
The size and location of the FBC service area contribute to a higher risk profile than for a utility with a larger footprint and a geographically and demographically diverse customer base. FBC's geography and service area pose similar risk as in the 2013 Proceeding.

2.3 *SHIFTING CUSTOMER PROFILE PRESENTS DIFFERENT CHALLENGES*

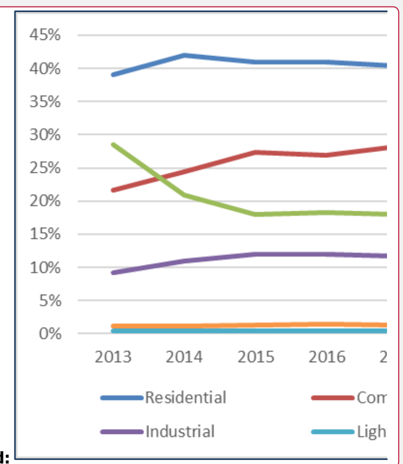
The risk profile of a utility is impacted by its overall customer class composition - that is, the proportion of total customers represented by a single broad customer type, such as residential, commercial, Industrial, and Wholesale groupings. Particularly relevant to FBC, the risk profile is also impacted by the proportion of total load that one particular customer group may comprise, even if the total number of customers in that group may be small. Generally, while diversity of customer characteristics is desirable from a risk perspective, a concentration of a significant proportion of overall load among a small number of customers is not. As shown in the figure below, FBC's customer profile by account type is typical of most utilities in that the majority of customers are in the residential sector. However, as shown in Figure B2-1 and as compared to the 2013-2014 period, the share of FBC's overall load profile in the Industrial sector is on an upward trajectory, increasing from 11 percent in 2013 to 14 percent in 2022. This trend leads to an increase in FBC's risk profile since Industrial load is more volatile and more prone to economic downturns. For instance, in 2019 FBC's Industrial load grew by 23 percent but the economic crises brought on by the COVID-19 pandemic caused Industrial load to drop by 11 percent in 2020.

Deleted: 9

Figure B2-1: The Trend in FBC's Load Profile by Customer Segment[15]



Deleted:



[15] 'S' in the chart x-axis labels refers to the Seed Year which is the year prior to the first forecast year in Annual Reviews. 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. 'F' refers to forecast.

Errata dated October 20, 2022

Figure B6-2: FBC Service Territory

FBC competes with BC Hydro in these underdeveloped areas where the borders of FBC's service area and BC Hydro's service area meet. BC Hydro's lower electricity rates are a factor in FBC's ability to expand beyond its currently serviced areas, but within the service area authorized by the *West Kootenay Power and Light Company, Limited, Act, 1897*. Customers building homes and businesses in the boundaries of FBC and BC Hydro service territory are not predetermined customers of either utility. Therefore, competition exists for FBC in these types of areas. The area outside the dark shaded area "FortisBC Service Area" and within the circle is currently served primarily by BC Hydro, although FBC has the statutory authority to expand into that area.

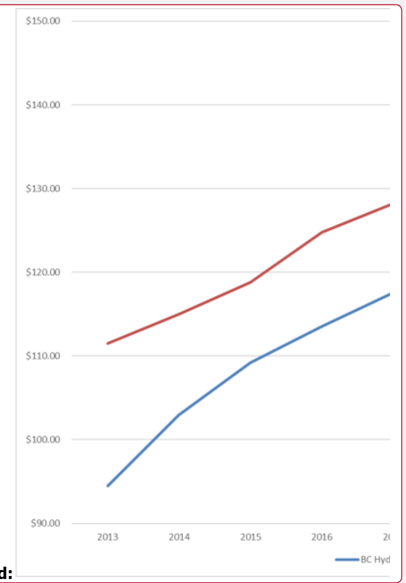
For example, as shown in Figure B6-3 below, based on usage of 1,000 kWh per month and including the basic Customer Charges, an FBC residential customer electricity bill was 27 percent higher than a BC Hydro residential customer electricity bill at January 1, 2022.

Deleted: 19

Errata dated October 20, 2022

Figure B6-3: Monthly Residential Bill Comparison

Deleted:



The relatively low price of electricity in BC Hydro's service territory compared to other jurisdictions like Alberta and Ontario and FBC's service territory within BC is largely reflective of Heritage or historical costs of supply. A large percentage of the costs making up BC Hydro's electricity rates are the low embedded costs of the province's hydro generation facilities. BC Hydro's current rates also do not reflect the full costs of providing electricity in BC, with significant deficiencies having accumulated in deferral accounts.[23]

As one can see from the general trend in the direction of rates shown in the above figure, BC Hydro rates are actually decreasing in absolute terms in the near term. Even as BC Hydro rates increase in the future, those increases affect FBC's power supply costs and therefore put additional upward pressure on FBC rates. BC Hydro has filed its Fiscal 2023-2025 Revenue Requirements Application with the BCUC, requesting an annual average bill increase of 1.1 per cent for the next three years. BC Hydro received approval for a rate decrease of 1.62 per cent starting April 1, 2021.[24]

[23] Clean Energy BC. Deferral and Regulatory Account Backgrounder. http://www.cleanenergybc.org/media/Deferral_and_Regulatory_Account_BACKGROUNDER_110602_DA_FINAL.pdf.

[24] https://www.bchydro.com/news/press_centre/news_releases/2021/rra-f23-f25.html.

Errata dated October 20, 2022

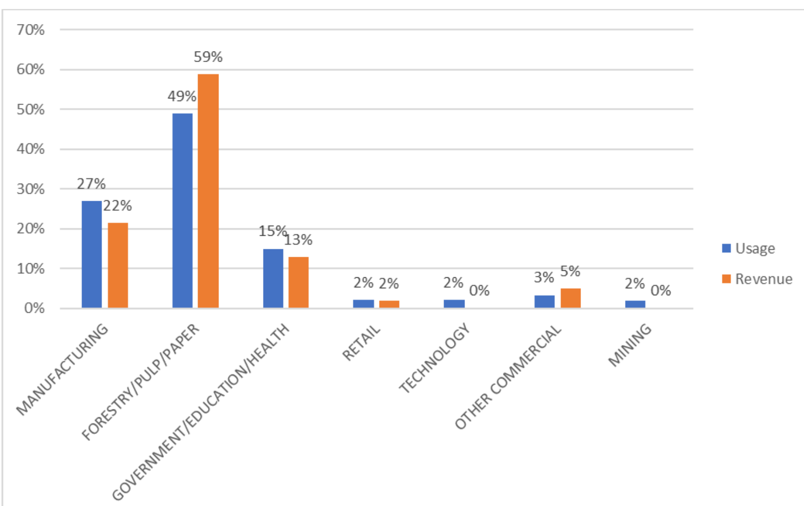
simply shutdown and move to another location as the Terms and Conditions of FBC's Electric Tariff only requires a customer to provide timely notice to FBC of termination of service.

As a general principle, if a utility's customer base is dominated by a small number of industries or large customers, the downturns in, or failures of, any one of those industries or customers is more likely to have a material impact on the utility than downturns or failures in an industry that accounts for a smaller proportion of the utility's overall load. FBC faces risk associated with being highly dependent on single large customers in only two industries – forestry and cryptocurrency mining.

FBC believes that the risk associated with the composition of its largest Industrial and commercial customers has increased slightly in recent years. This is because the mix of load continues to be dominated by a small number of customers in a few industries, namely, those related to the forest sector, as has historically been the case, and now with technology-related load associated with cryptocurrency, the shift from one to the other increases the risk profile.

Figures B7-1 and B7-2 below illustrate the changes to the company's load and revenue diversity from 2013 to 2020. In 2013, 49 percent of the load and 59 percent of the revenue attributable to the largest 20 customers was in the forestry industry, which included 9 customers. The other two significant contributors to load were in the manufacturing and institutional sectors, made up of government, education and health related accounts. In 2020, these aforementioned industries remained as key factors in overall load, and the emergence of the technology sector is driven primarily by a single cryptocurrency customer.

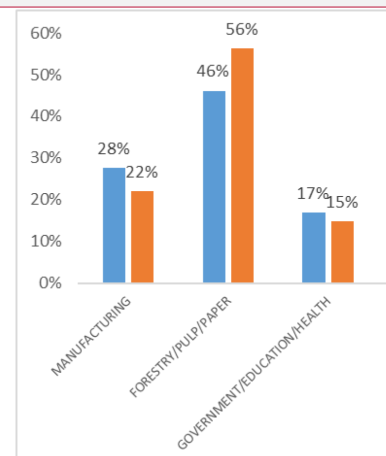
Figure B7-1: Industry of FBC's Top Twenty Industrial Customers by Load and Revenue in 2013



Deleted: 6

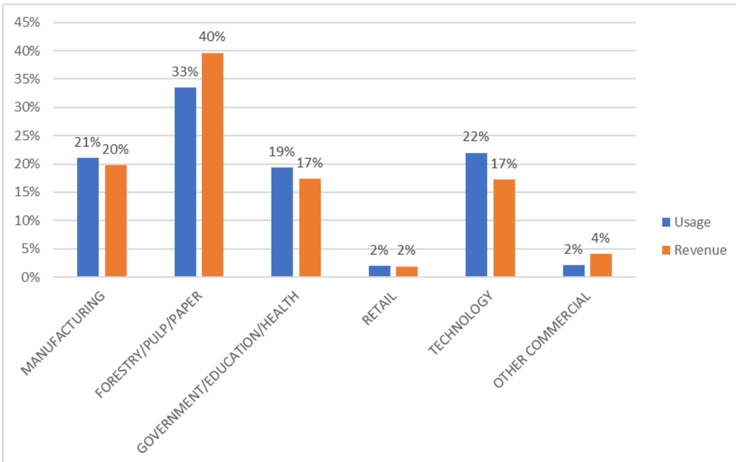
Deleted: 6

Deleted:

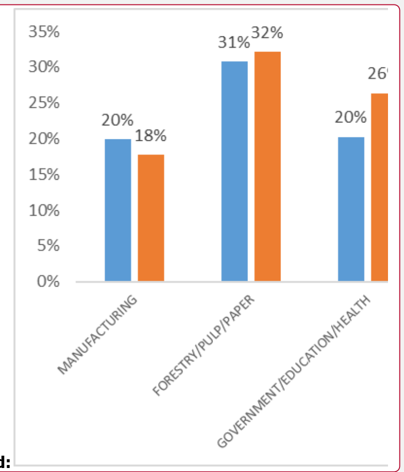


Errata dated October 20, 2022

Figure B7-2: Industry of FBC's Top Twenty Industrial Customers by Load and Revenue in 2020



Deleted:



Adding a cryptocurrency customer is beneficial in the sense that it adds new industrial load that is not from the forestry sector, but cryptocurrency mining comes with considerable uncertainty as the utility industry as a whole has little experience with it. Cryptocurrency mining requires large amounts of electricity. Cryptocurrency mining load, however, is heavily tied to market fluctuations of digital currencies. The inherent volatility of the virtual mining industry and its uncertain future creates challenges for electric utilities engaged in long-term resource planning. For FBC, the cryptocurrency industry today is comprised of a single customer. While FBC has no indication that this customer has any intention of being other than a long-term stable load, it is generally understood that cryptocurrency customers are especially price-sensitive and more mobile than is generally the case.

The forestry industry is sensitive to world commodity prices, to the strength of the U.S. and Pacific Rim economies, and to the strength of the Canadian dollar. Factors such as strikes and trade disputes can also negatively impact the forestry industry generally, or specific plants or mills. A downturn or permanent decline in the forestry industry will have secondary effects in the economy, e.g., on commercial enterprises that cater to this industry, as well as on the disposable income of direct and indirect employees. The long-term health of the BC pulp and paper sector is dependent on the BC industry's ability to compete in global markets. The most recent information compiled by the provincial government with respect to the forestry sector is the *2019 Economic State of the British Columbia Forest Sector Report*. The overview from this report notes, "…softened demand in major export countries, a lengthy labour dispute on the Coast, coupled with fibre supply issues caused by the Mountain Pine Beetle epidemic…", as the main factors behind a difficult 2019. National Resources Canada has also produced its annual report, *The 2020 State of Canada's Forests Annual Report: An Overview* which points out that, "…uncertainty in global trade, changes in consumer demands, and increasing international competition are challenging Canada's forest

Errata dated October 20, 2022

Attachment 2

ERRATA DATED OCTOBER 20, 2022
CLEAN CONSOLIDATED VERSION

British Columbia Utilities Commission 2022 Generic Cost of Capital (GCOC) Proceeding – Stage 1

Appendix A

FortisBC Energy Inc.

Business Risk Assessment

Table of Contents

Index of Tables

Index of Figures

1. OVERVIEW OF BUSINESS RISK

The assessment of a utility's risk profile is an essential element of its cost of capital estimation process. This Appendix describes FEI's overall competitive, operating, policy and regulatory environment using broadly similar categories of business risk and risk factors to those used in the company's 2016 cost of capital proceeding (2016 Proceeding) filing, albeit with some adjustments to naming conventions for clarity and, one new category. FEI's overall business risk in this Proceeding is best characterized as being **significantly higher** than in 2015.

1.1 *BUSINESS RISK CATEGORIES AND FACTORS*

FEI identified nine business risk categories, as presented in Table A1-1 below. FEI used the same categories in the 2016 Proceeding, other than the Indigenous Rights and Engagement risk factor, that has now been promoted to its own risk category. Other risk factors and categorizations are possible, and some risk factors could be captured under a different risk category.[1] However, using the same categories in this proceeding facilitates the comparison of FEI's risk profile with business risk information presented during the 2016 Proceeding, so as to provide a directional indication.

Table A1-1: Business Risk Categories and Risk Factors Addressed in this Appendix

Business Risk Category	Risk Factors
Business Profile	• Type and size of utility • Service area • Customer profile
Economic Conditions	• Overall economic conditions
Political	• Climate action goals and expectations • Energy policies and legislation
Indigenous Rights and Engagement[2]	• Legislative and policy developments • Aboriginal rights and title • Social license / work interruption
Energy Price	• Commodity price • Commodity price volatility • Price competitiveness and carbon tax

[1] For example, availability of energy supply which is listed under the Energy Supply risk category could also be included as a risk factor under Energy Price because the availability of supply of an energy form can impact its price.

[2] This category was a sub-category of Political Risk in the 2016 Proceeding.

Business Risk Category	Risk Factors
Demand/Market[3]	• Perception of energy • New technology and energy forms • Net customer additions • Changes in building type and capture rates • Changes in end-use market share • Changes in use per customer
Energy Supply	• Availability of supply • Access to supply • Renewable Gas supply
Operating	• Aging infrastructure and time dependent threats • Third party damages • Attitudes towards fossil-fuel industry • Municipal operating challenges • Cybersecurity • Unexpected events
Regulatory	• Regulatory uncertainty and lag • Administrative penalties

1.2 SUMMARY ASSESSMENT OF FEI'S BUSINESS RISK

Table A1-2 provides a summary assessment of whether the risk to FEI associated with particular risk categories and factors are higher/lower/similar relative to how they were represented in the 2016 Proceeding or are recognized as a new risk for this Proceeding. At present, while all of the risk categories are important contributors to FEI's overall business risk, FEI highlights **political risk** and **regulatory risk** in particular as the risk categories where changes can have the greatest potential to affect FEI's ability to earn its return on, and of, invested capital.

Table A1-2: Summary of FEI's Business Risk

Business Risk Category	Risk Factor	Change in Risk Since 2016
Business Profile		**Similar**
	Type and size of the utility	Similar
	Service area	Similar
	Customer profile	Higher
Economic Conditions		**Higher**
	Overall economic conditions	Higher
Political		**Higher**
	Climate action goals and expectations	Higher
	Energy policies and legislation	Higher

[3] This category was referred to as Market Shifts in the 2016 Proceeding.

Business Risk Category	Risk Factor	Change in Risk Since 2016
Indigenous Rights and Engagement		**Higher**
	Legislative and policy developments	Higher
	Aboriginal rights and title	Higher
	Social license/work interruption	Higher
Energy Price		**Higher**
	Commodity price	Higher
	Commodity price volatility	Higher
	Price competitiveness and carbon tax	Higher
Demand/Market		**Higher**
	Perception of energy	Higher
	New technology and energy forms	Higher
	Net customer additions	Higher
	Changes in building type and capture rates	Similar
	Changes in end-use market share	Higher
	Changes in use per customer	Similar
Energy Supply		**Similar**
	Availability of supply	Similar
	Access to supply	Similar
	Renewable Gas supply	New (Higher)
Operating		**Higher**
	Aging infrastructure and time dependent threats	Similar
	Third party damages	Similar
	Attitudes towards fossil-fuel industry	New (Higher)
	Municipal operating challenges	New (Higher)
	Cybersecurity	New (Higher)
	Unexpected events	Higher
Regulatory		**Higher**
	Regulatory uncertainty and lag	Higher
	Administrative penalties	Similar

The key points from this "snapshot" regarding the relative risk of FEI compared to the analyses completed for the 2016 Proceeding (which were based on 2015 data), discussed throughout this Appendix, are summarized by business risk category below.

- *<u>Business Profile</u>:* FEI's primary market continues to be residential and commercial space and water heating end-uses. Despite some shift in load to the industrial and low carbon transportation (LCT) sectors, which are both more volatile and more sensitive to economic conditions, FEI assesses its overall business profile risk to be similar to the 2016 Proceeding.

- *<u>Economic Conditions</u>:* The current Canadian economic environment continues to be dominated by uncertainty. FEI's assessment of major economic indicators indicates that BC is recovering from the pandemic lows. Nevertheless, the record high inflation rate, caused by government fiscal and monetary policy to boost economic growth and improve employment, and BC's challenges for long-term economic growth points to higher risk.
- *<u>Political</u>:* The increase in political risk is the most notable of all of the risk factors. Government policies and regulations at all levels, as well as stakeholder interests, have a significant impact on FEI's operations, competitiveness and ability to achieve its important initiatives. The overall thrust of climate change and energy policies is moving at a more rapid pace than at the time of the 2016 Proceeding and the role of natural gas, or even Renewable Gas, within the province's future energy landscape is unclear. While FEI believes that gas infrastructure is an optimal tool to reach decarbonization goals, there is a lack of awareness and acceptance of that role, given it is not directly discussed in net-zero climate goals and plans. This is apparent in the provincial government's recently updated CleanBC Roadmap to 2030 (Roadmap)[4] which is anticipated to have a significant impact on FEI's competitive and operational landscape with implications for customer rates and throughput. The Roadmap introduced a Greenhouse Gas Reduction Standard (GHGRS) that establishes a greenhouse gas (GHG) reduction obligation for natural gas utilities to reduce emissions from energy delivered to the buildings and industrial sectors. Although the full extent of the impacts are not yet known, the short timeframe by which to reduce GHG emissions to meet the GHGRS cap represents substantial risk to FEI. FEI's risk is further compounded by the fast pace of legislation and policies on electrification initiatives and BC Hydro's Electrification Plan[5], which increases competition from electricity. FEI assesses that its political risk has increased significantly relative to the political risk environment at the time of the 2016 Proceeding.
- *<u>Indigenous Rights and Engagement</u>:* FEI has made Indigenous Rights and Engagement risk its own category (instead of being one of the risk factors under Political Risk) to reflect the increasing significance of these considerations for FEI's overall business. FEI defines Indigenous Rights and Engagement risk as the potential for utility operations to be negatively impacted by policy or legislation concerning Aboriginal rights and title or by Indigenous groups intervening directly in the utility regulatory process or by asserting Aboriginal rights and title. As provincial and federal governments navigate reconciliation and implement the UN Declaration on the Rights of Indigenous Peoples, FEI has assumed a higher level of business risk related to its relationship with Indigenous groups compared

4 https://cleanbc.gov.bc.ca/.
5 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/electrification/Electrification-Plan.pdf.

to what it anticipated at the time of the 2016 Proceeding. Indigenous groups in BC are diverse and the added uncertainty from outstanding claims to Aboriginal title and rights further complicates the landscape within which FEI operates. Combined with regulatory updates that have increased consultation requirements and included a focus on seeking consensus and consent of Indigenous groups, as well as the risk of litigation in the absence of consent, FEI faces an elevated risk of cost escalation, project delays and/or projects being denied approval.

- *Energy Prices:* The risk relating to energy prices is higher than what it was in the 2016 Proceeding. Current market prices for natural gas are higher than in 2015 and forecasted to increase as demand from power generation and liquefied natural gas (LNG), and a potential decline in crude oil production, puts pressure on prices. Furthermore, market prices are expected to remain volatile as a result of extreme weather events, changes in natural gas demand for power markets in the region, and anticipated growth in demand to supply the LNG export market. The volatility is greater than that presented in the 2016 Proceeding. In terms of competitiveness, the current price advantage of natural gas versus electricity is not expected to be maintained, especially with recent rate announcements from BC Hydro which will see electricity rates held fairly flat over the next several years. Current and planned carbon tax rates will continue to negatively affect natural gas price competitiveness relative to electricity. Further, the increasing share of higher cost Renewable Gas in FEI's gas supply portfolio further contributes to FEI's higher price competitiveness risk. The upfront and installation costs of natural gas-fired equipment have increased relative to the cost data available in 2015 for that same equipment. Moreover, new technology which supports the use of electricity, such as electric heat pumps, that have a higher upfront and installation cost than natural gas-fired equipment, are more cost competitive when government-provided incentives and rebates are considered.

- *Demand/Market:* Overall, since the 2016 Proceeding, FEI's demand/market risk has increased. Customers' energy choices are increasingly influenced by a desire to minimize negative environmental impacts. While Renewable Gas can be a relatively affordable option to achieve this goal, the electric options such as high-efficiency heat pumps are gaining faster and more widespread traction among customers and policy makers. FEI is already experiencing the effects of this shift in its net customer additions, particularly in the residential sector, where due to BC's high turnover rate, a large segment of its existing customers homes may be torn down and rebuilt with electric-only options to meet more stringent code requirements. Further, the gradual decline in the single-family dwelling (SFD) segment, where FEI has higher capture rates, in favour of multi-family dwellings (MFD) and the downward trend in the share of natural gas in space heating and water heating applications continue to impact FEI's risk profile. FEI's new residential customers continue to have lower use per customer than average residential customers do. This is somewhat offset by load growth in the more volatile and economically sensitive transportation and industrial sectors.

- *Energy Supply:* Relative to 2015 levels, FEI's energy supply risk remains similar. Availability and accessibility of natural gas supply to FEI's service territory remains unchanged, as natural gas producers forecast production increases to meet growth in demand for gas-fired power generation and LNG. In terms of delivery risk, FEI continues to rely on a single system for a significant portion (currently 80 percent) of its gas requirements, and the material supply risk that this represents was highlighted in 2018 when Enbridge's T-South pipeline (or Westcoast T-South system) ruptured. The expansion of FEI's Renewable Gas supply adds new energy supply risk considerations since the 2016 Proceeding, such as the risks of lower than expected supply volume, competition from other purchasers, natural gas system readiness, and acceptance of non-local supply.

- *Operating:* FEI's overall operating risk has increased since the 2016 Proceeding. Operating risk factors continue to include infrastructure integrity and time dependent threats, and third party damages. Unexpected events also continue to contribute to FEI's operating risks. Since 2015, events such as the COVID-19 pandemic and the Enbridge T-South pipeline rupture, as well as more frequent extreme weather events, have highlighted the ever-changing nature of unexpected events facing FEI. While these types of operating risks have always been present, there is a growing recognition in the industry of utility exposure to significant unforeseen events and the importance of resiliency. Furthermore, unlike in the 2016 Proceeding, FEI now identifies its operating risks as including negative sentiment towards companies within the fossil-fuel industry which increases the risk of protests and environmental activism against utility assets, challenges recruiting top talent to a carbon-based industry and poses difficulty and delays in obtaining capital project approvals or operating permits, and increases cybersecurity risk across many aspects of its operations. FEI is also facing municipal challenges to its right to construct and operate that were not previously experienced as frequently or at the level FEI experiences today. All of these factors working together increase FEI's overall operating risk.

Regulatory: The degree to which FEI, as a regulated public utility, is dependent on regulators for timely and objective approvals that directly impact its ability to earn a fair return on and of capital is what is referred to in this section as regulatory risk. FEI has assessed its overall regulatory risk as higher than what was assessed in FEI's 2016 Proceeding, with certain risk factors increasing and others being similar. The BCUC's jurisdiction is confined to what is conferred by the *Utilities Commission Act* (UCA), but within that framework the BCUC has significant discretion in the exercise of those powers. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty which in itself gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FEI with an opportunity to earn its fair return, or that necessary investments are not approved. The underlying BCUC regulatory framework remains the same, but there are new developments that merit note. There is uncertainty caused by the level of regulatory support for the implementation of certain initiatives and the BCUC's decision to consider a more generic approach to deferral account financing treatment. The risk associated with regulatory lag and ultimate approval of cost recovery has also increased since the 2016 Proceeding, with new challenges in both BCUC and other regulatory processes. There are increased requirements for stakeholder consultation, environmental reviews, Indigenous rights and title and municipal operating challenges.

Considered together, FEI's overall business risk is best characterized as being significantly higher relative to its risk at the time of the 2016 Proceeding.

2. BUSINESS PROFILE

As business risk is specific to a particular utility, it is important to understand the fundamental characteristics (or business profile) of the utility being assessed. FEI's analysis indicates that, while aspects of FEI's business profile are adding risk, compared to the 2016 Proceeding FEI has assessed the business profile risk as similar overall. The main points discussed in the following sections are:

- Section 2.1 discusses that FEI remains a relatively large utility whose primary market is selling natural gas to its core customers and there is no fundamental change in its size or type.
- Section 2.2 explains that FEI's service area is unchanged.
- Section 2.3 discusses that FEI has been expanding its service offerings with the goal of offsetting the loss of core residential and commercial load. Early experience has shown the challenges in the low carbon and transportation sector, and the extent to which FEI will be successful in growing load in this sector is uncertain. Even with success, this load is not a one for one replacement in terms of risk due to the nature of the load.

2.1 *TYPE AND SIZE OF THE UTILITY ARE RELATIVELY UNCHANGED*

FEI is the largest distributor of natural gas in British Columbia, serving approximately 1,060,000 residential, commercial, industrial, and transportation customers in more than 135 communities. FEI provides transmission and distribution services to its customers, and obtains natural gas supplies on behalf of most residential, commercial, and industrial customers.

FEI's core business continues to be serving space and water heating load in the residential and commercial sectors. This market continues to experience competitive challenges, which are central to FEI's overall business risk. FEI also serves industrial and LCT sectors that are increasing in importance in its business profile. Table A2-1 summarizes FEI's overall business profile in 2015 and in 2022.

Table A2-1: FEI's Business Profile[6]

	2015[7]	2022[8]
Type of Utility	Local Distribution Company (LDC)	
Energy Product Offering	Natural gas, biomethane, propane	
Service Area	Mainland, Vancouver Island, and Whistler	
Rate Base ($000s)	3,661,370	5,409,207
Sales/Transportation Volumes (TJ)	176,035	234,057
Average Number of Customers	970,389	1,068,458
Customer Profile by Demand		
Residential	42%	41%
Commercial	32%	29%
Industrial	26%	31%
Customer Profile by Sales Revenue		
Residential	60%	57%
Commercial	33%	30%
Industrial	7%	12%

Overall, FEI assesses that the risk related to the type and size of its gas utility is similar to the 2016 Proceeding. FEI remains a relatively large natural gas distribution utility and although the risk of this type of utility has increased, this risk is covered off under other sections. Further, although rate base has increased by almost 50 percent since 2015, growth in demand and customers has not kept pace. There is some greater diversification of demand paired with a shift to more volatile market segments.

2.2 FEI'S SERVICE AREA CONCENTRATED IN LOWER MAINLAND

FEI's business profile risk is further impacted by its regional consumption profile. Figure A2-1 below provides FEI's business profile by region. As can be seen, the majority of FEI's volume, revenue and customers are in the Lower Mainland region followed by the Inland and Vancouver Island regions. The significant share of Lower Mainland consumption in FEI's profile is a risk factor since, as discussed in Section 4.2.3 in the context of Political risk, many of the municipalities

[6] This table excludes data for the Fort Nelson service area. Fort Nelson's 2021 Approved rate base is $12,503 thousand.

[7] Numbers from FEI's Annual Review for 2015 rates.

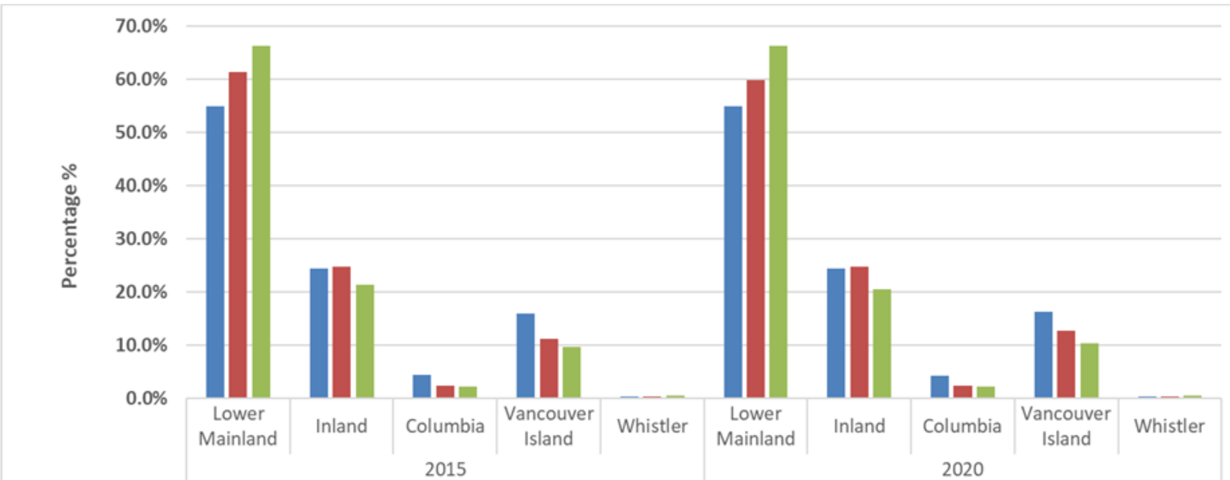
[8] Numbers from FEI's Annual Review for 2022 Rates:

- Residential includes Rate Schedule 1. Commercial includes Rate Schedules 2, 3, 23.
- Industrial includes Rate Schedules 4, 5, 6, 7, 22, 25, 27, 46.
- With the exception of the rate base amount, all the numbers are for non-bypass customers only. Bypass Transportation volume equals 33,112 TJs and Revenue equals $21,884 thousand.

Errata dated October 20, 2022

within this region are pursuing aggressive carbon free policies that can hinder FEI's ability to add new customers or retain existing customers. While the proportion of FEI's customers in the Whistler and Vancouver Island regions has increased in recent years, it is not significant enough to change FEI's business profile in a meaningful way and/or reduce its reliance on the Lower Mainland region's load and revenue.

Figure A2-1: FEI's Business Profile by Region[9]



	2015 Lower Mainland	2015 Inland	2015 Columbia	2015 Vancouver Island	2015 Whistler	2020 Lower Mainland	2020 Inland	2020 Columbia	2020 Vancouver Island	2020 Whistler
Volume	54.9%	24.4%	4.4%	15.9%	0.4%	54.9%	24.3%	4.2%	16.2%	0.4%
# of customers	61.5%	24.7%	2.4%	11.2%	0.3%	59.9%	24.7%	2.3%	12.7%	0.3%
Revenue	66.2%	21.4%	2.3%	9.7%	0.5%	66.3%	20.6%	2.2%	10.4%	0.5%

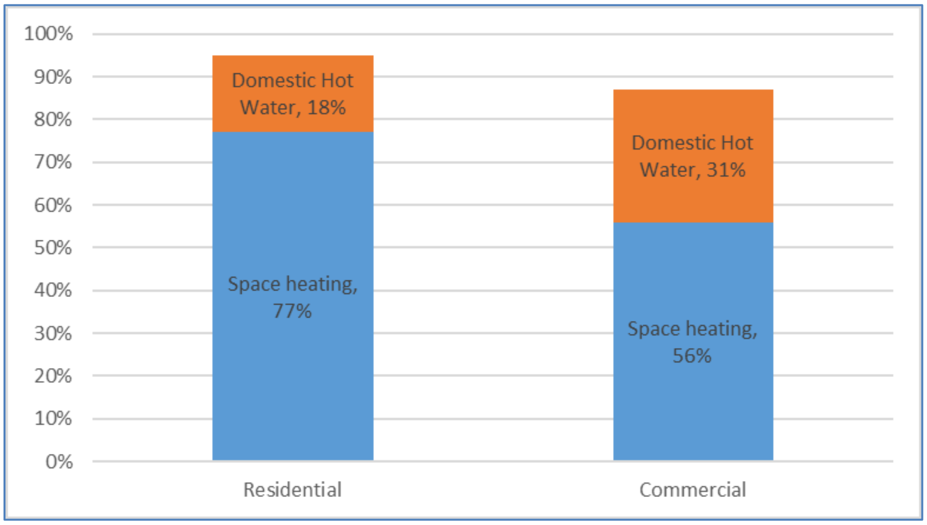
2.3 *SHIFTING CUSTOMER PROFILE PRESENTS DIFFERENT CHALLENGES*

The fact that the majority of FEI's delivery margin and revenue are generated from residential customers is significant because FEI faces its greatest challenges in maintaining its share of the residential market. FEI assesses that its customer profile risk is higher compared to the 2016 Proceeding, both due to the increased risk to maintaining load in the core residential and commercial sectors, and that the load being added to mitigate those losses is subject to greater volatility and market conditions.

Figure A2-2 below demonstrates that in FEI's residential and commercial sectors, space and water heating are the dominant end uses, accounting for about 95 percent and 87 percent of the energy consumption respectively for each sector.

9 Percentages are calculated based on 2020 actual normalized data.

Figure A2-2: Residential and Commercial Consumption by End Use[10]



Note: Residential Space Heating includes fireplace end-use at 15% of total residential consumption

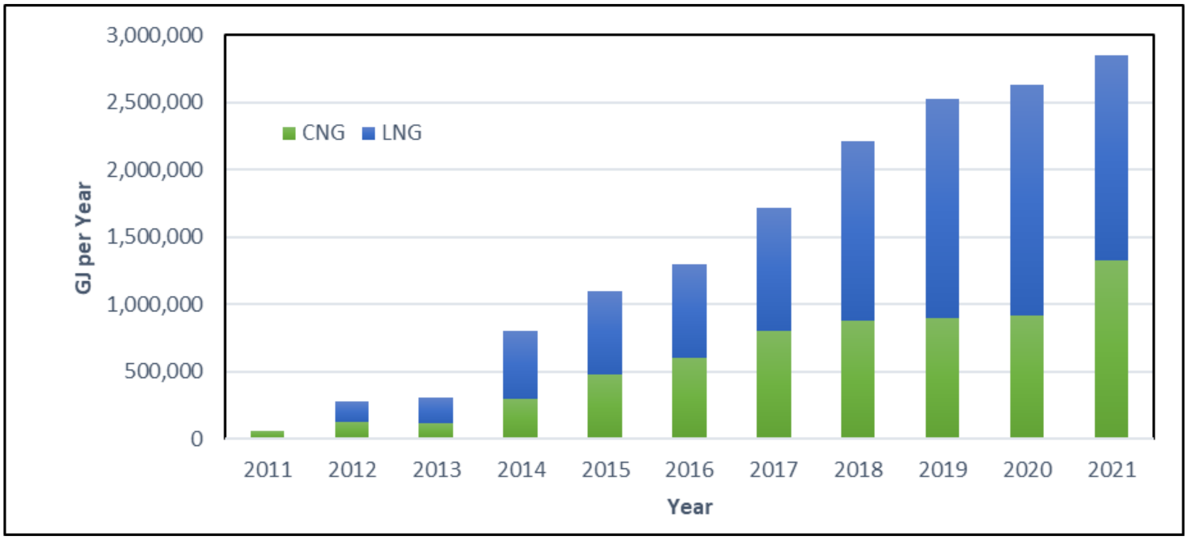
Thus, the space and water heating end-uses in residential and commercial sectors are FEI's largest market for natural gas consumption. Many government policies designed to curb GHGi emissions in the building sector, described in Section 4.2, are targeting these two markets. As explained in Section 7.5, the evidence indicates that FEI's share of space heating and water heating is on a downward trend while electricity is gaining market share in these two crucial sectors.

At the same time, FEI is experiencing growth in its industrial and LCT sectors. Although this leads to some diversification of load, the energy demand in these sectors tends to be more volatile than residential use and, all else equal, the increased share of this type of load in FEI's load and revenue profiles will lead to higher revenue (and potentially earnings) volatility going forward. For instance, the LCT sector's LNG demand and revenue took a much larger hit from the COVID-19 pandemic than the residential or commercial sectors. As an example, actual LNG Service volumes for 2020 increased year-over-year by 5 percent compared to the 2019 year-over-year increase of 22 percent. More recently, there was a significant 11 percent decrease in load for 2021 compared to 2020.

The growth of LCT is primarily driven by the Greenhouse Gas Reduction Regulation (GGRR). The GGRR allows FEI to incentivize eligible vehicles and upgrades to maintenance facilities, invest in refueling infrastructure, and provide safety and training programs. As Figure A2-3 below illustrates, consumption by CNG and LNG customers combined is increasing.

[10] Based on 2019 data.

Figure A2-3: CNG and LNG Sales Volume (2011-2021)



In 2021, total consumption for CNG and LNG customers was approximately 2.85 million GJs, which represents a 9 percent growth over 2020. However, FEI's LCT sales have not achieved the levels forecast at the time of the 2016 Proceeding. For instance, the total LCT demand for 2017 in the 2016 Proceeding was forecast at 4.4 PJs which is significantly higher than the actual realized load in the same year or even compared to the 2021 demand. In other words, diversification through growth of the LCT business has not been as rapid as anticipated at the time of the 2016 Proceeding.

FEI discusses the compressed natural gas (CNG) and LNG markets below.

CNG and LNG Vehicles

FEI continues to develop and expand the CNG transportation market. To further support the use of CNG vehicles and related infrastructure, FEI incentivized 871 CNG powered vehicles as of December 31, 2021, bringing the total number of incentivized compressed and liquefied natural gas powered vehicles on road to 1,019.

FEI is seeing an emergence of customer interest in alternative LCT technologies such as battery electric and hydrogen fuel cell vehicles. There are currently no commercially proven, widely available battery-electric and hydrogen offerings for medium and heavy-duty vehicles, which is the target market for FEI, with the exception of technology demonstration projects for battery-electric transit buses in BC. Economic and operational challenges continue to hinder the emergence of these low-carbon solutions. As battery-electric and hydrogen technology progresses, FEI anticipates that all forms of low- and zero-carbon transportation fuels including Renewable Gas, battery-electric and hydrogen will all have a role in reducing emissions in the province. No single solution will dominate zero- and low-carbon transportation in the medium and heavy-duty vehicle classes in the next ten to fifteen years; a portfolio of technologies will be needed for specific applications. The North American Council for Freight Efficiency (NCAFE)[11] report titled "Viable Class 7/8 Electric, Hybrid, and Alternative Fuel Tractors" determines that renewable diesel, CNG, and Renewable Gas fuels are at parity with diesel today on weights and range, and result in lower emissions than diesel. The report concludes that CNG and Renewable Gas vehicles will play a vital role in the medium and heavy-duty vehicle industry for the next ten to twenty years while the market transitions toward battery-electric and hydrogen technologies.

FEI believes that the ability to offer Renewable Gas as a drop-in fuel to CNG and to LNG will provide a viable option for customers to further decarbonize without incurring any additional capital expenditure. Given the risks with the emergence and adoption of new lower carbon fuel types, FEI believes Renewable Gas to be a viable alternative to battery-electric and hydrogen fuel sources for achieving equivalent lifecycle emissions reductions. Another benefit to adopting Renewable Gas as a transportation fuel is the ability for customers to monetize carbon credits and mitigate the incremental premium associated with the Renewable Gas commodity price. Yet, as discussed in Section 4.2.2.1.5, changes to BC's Low Carbon Fuel Standard may affect carbon credits for CNG customers. The long-term success and continued adoption of natural gas vehicles for the medium and heavy-duty is predicated on FEI's ability to secure Renewable Gas supply for the transportation market. The risk associated with Renewable Gas supply is discussed in Section 8.3.

LNG

LNG AS A MARINE FUEL

Within the LNG segment, there are two key marine segments that FEI targets: short sea and trans-Pacific. FEI has made significant commitments for a total of ten short sea marine vessels (six for BC Ferries and four for Seaspan) which have been incentivised through the GGRR. Seaspan has no plans to add any additional LNG-powered vessels to their fleet. At this time, BC Ferries does have plans to replace their five major class ferries with LNG as they are expected to be upgraded in the next two to four years; however, it is possible that BC Ferries may electrify some of the major class ferries or adopt hydrogen should the technology be commercially proven and infrastructure is readily available at a competitive price. FEI is working closely with BC Ferries and monitoring all technologies; however, there is a risk that future growth and adoption for LNG as a marine fuel may be capped at the current ten vessels.

There are three methods of LNG bunkering: truck-to-ship, ship-to-ship, and shore-to-ship. FEI currently only has capability for truck-to-ship. The current truck-to-ship fueling method works well for regional ferry and small vessel operators with relatively small fuel capacities. However, trans-Pacific vessels requiring larger LNG transfer volumes will need a ship-to-ship LNG fueling method, which is the current method used to fuel trans-Pacific vessels with traditional marine fuels. FEI expects this capability to be developed sometime in 2023 or 2024, and is working in conjunction with the Vancouver Fraser Port Authority and other key stakeholders. This capability

[11] https://nacfe.org/emerging-technology/electric-trucks-2/viable-class-7-8.

will be developed by third-party bunker service providers who will own, operate, and manage the bunker vessel and the delivery of fuel to customers. Reliance on these third party bunker service providers to develop this capability required to support the expansion of the LNG sales market introduces additional risk when it comes to capturing this bunkering market.

The Tilbury Pacific Marine Jetty Project, of which FortisBC Holdings Inc (FHI) is a co-proponent, which would allow for bunkering from shore-to-ship, using LNG produced by FEI, is currently completing an environmental assessment (EA) under the direction of the BC Environmental Assessment Office. The EA is expected to conclude later in 2022. If approved, construction could begin in 2023 and the jetty could be in limited service for marine LNG fuelling by the end of 2024. In addition to the EA approval, an Oil and Gas Commission (OGC) permit is required for construction. In other words, they are subject to regulatory risk that could delay or hinder the success of the project which FEI is relying upon to grow LNG sales. There is also significant construction required for the project to proceed and construction contracts have not yet been signed.

LNG CONTAINER EXPORTS

There continues to be a significant demand for containerized LNG in Asia as Asia moves away from coal and diesel to a less carbon intensive future. As the world economies came back online in 2021, China, South Korea and Japan saw the quick return of manufacturing which placed a burden on the supply chain. When ports opened, there was an unprecedented pent up demand for consumer goods causing port congestion and shipping rates to increase to historic highs. LNG container sales are also impacted by the Dangerous Goods designation at domestic ports and on international shipping vessels, limiting the amount of LNG that can be shipped at one time. FEI is currently working with the port operators, Provincial and Federal Trade Departments, and end user customers to try and facilitate LNG container sales by private charter vessels and smaller, more versatile breakbulk ships. FEI continues to see interest and demand from overseas markets and anticipates that sales will return once these factors subside. FEI believes that while there is optimism for the future, this recent change in demand for LNG container exports highlights the risk of this market segment given its sensitivity, and thus sales volatility, to external economic factors.

LNG AS AN ON-ROAD TRANSPORTATION FUEL

The prospects of LNG as an on-road transportation fuel have deteriorated since the 2016 Proceeding. Four out of the seven LNG stations built by FEI have been closed due to customers shifting away from LNG as an on-road transportation fuel. Until recently, there has been little development in the production of higher horsepower engines for heavy-duty long haul trucking and as such, LNG is slowly becoming a less popular option for fleet owners looking to reduce emissions. FEI continues to serve current LNG on-road customers and will continue to do so as long as these customers require fuel and may again support the LNG on-road sector once a new higher horsepower engine is commercially available.

In summary, FEI's primary market continues to be residential and commercial space and water heating end-uses. Despite some shift in load to the industrial and LCT sectors, which are both more volatile and more sensitive to economic conditions, FEI assesses its overall business profile risk to be similar to the 2016 Proceeding.

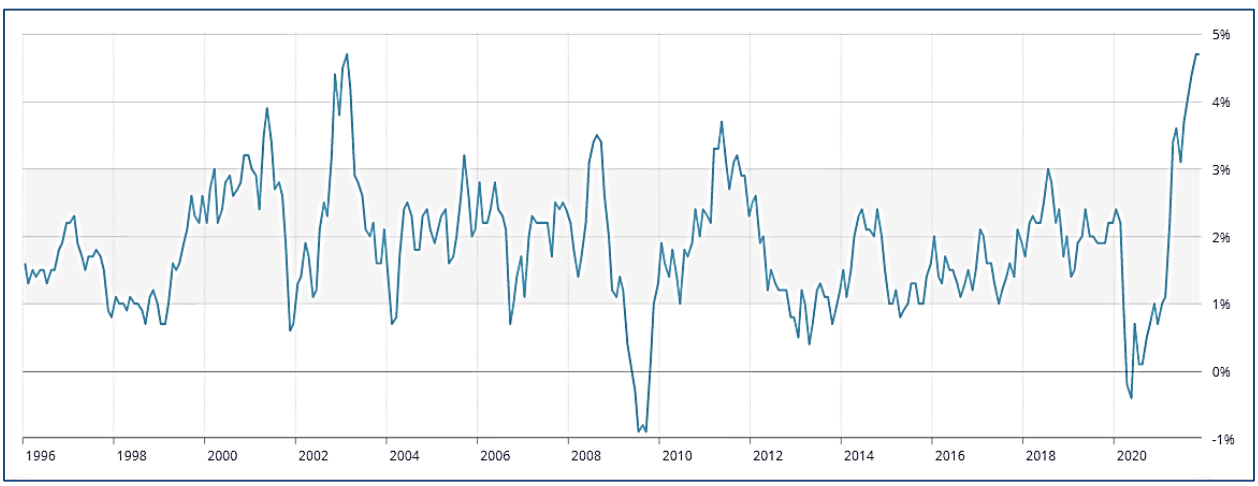
3. ECONOMIC CONDITIONS

Economic conditions can affect the ability of utilities to attach new customers or retain existing customers and maintain throughput levels, in addition to affecting utility access to capital and cash flow from customers. Compared to the 2016 Proceeding, and considering the unprecedented economic turmoil and uncertainty caused by the COVID-19 pandemic and record high inflation numbers due to government fiscal and monetary policy to boost economic growth and improve employment as well as BC's challenges for long-term economic growth, FEI assesses that the economic condition risk has increased.

The COVID-19 pandemic, one of the most disruptive economic events in modern history, continues to wreak havoc on normal economic activity as the rise of COVID-19 variants puts downward pressure on Canada's economy forcing both federal and provincial governments to record deficit spending and the central banks to implement unprecedented monetary policies to maintain access to capital markets. These efforts, along with the global supply bottlenecks, have resulted in increased inflationary pressure not seen in the last 30 years[12], further reducing buying power for those on fixed incomes.

The 2020 economic shutdown resulted in the worst annual GDP downturn in the last 20 years. This historical decline was followed by a material economic recovery in 2021 as the economy started to re-open. However, as shown in the figure below, the 2021 economic rebound is accompanied by a sharp increase in consumer prices which, relative to the last decade and the Bank of Canada's target inflation range, are at elevated levels.

Figure A3-1: Canada's Consumer Price Index (1996 until November 2021)[13]



[12] According to Statistics Canada inflation for the month of December rose to 4.8%, the highest print since it reached 5.5% in September 1991.

[13] Bank of Canada; Retrieved from https://www.bankofcanada.ca/rates/indicators/key-variables/key-inflation-indicators-and-the-target-range/.

Table A3-1 below summarizes the changes in leading economic indicators for four major provinces across Canada. As shown, while all four provinces faced negative economic growth in 2020, BC experienced the lowest decline. With regards to the housing starts however, Ontario and Quebec's 2020 housing starts were higher than the 2019 housing starts while's BC 2020 housing starts declined. Further, unemployment numbers in Quebec and BC are close and faring better than the other two provinces.

Table A3-1: Economic Indicators for Four Jurisdictions in Canada (2015 to 2023)[14]

	2015	2016	2017	2018	2019	2020	2021F	2022F	2023F
British Columbia									
Real GDP (% change)	2.3	2.9	3.7	2.8	2.5	-3.8	5.2	4.0	2.5
Unemployment (%)	6.2	6.1	5.2	4.7	4.7	8.9	6.5	4.7	4.5
Housing starts (1000 of units)	31.4	41.8	43.7	40.9	44.9	37.9	47.6	36.1	34.8
Alberta									
Real GDP (% change)	-3.5	-3.6	4.3	1.9	0.0	-8.2	5.3	5.0	4.0
Unemployment (%)	6.1	8.2	7.9	6.7	7.0	11.4	8.7	7.1	6.4
Housing starts (1000 of units)	37.3	24.5	29.5	26.1	27.3	24	31.4	30.9	28.8
Ontario									
Real GDP (% change)	2.7	2.2	2.8	2.9	2.1	-5.0	3.9	4.9	3.2
Unemployment (%)	6.8	6.6	6.0	5.7	5.6	9.6	8.0	5.8	5.3
Housing starts (1000 of units)	70.2	75.0	79.1	78.7	69.0	80.8	99.5	83.6	83.3
Quebec									
Real GDP (% change)	1.0	1.6	2.9	3.0	2.7	-5.3	5.9	3.6	2.4
Unemployment (%)	7.6	7.2	6.1	5.5	5.1	8.9	6.1	4.6	5.0
Housing starts (1000 of units)	37.9	38.9	46.5	46.9	48.0	53.4	67.8	54.8	49.4

Focusing on BC, BC's economy fell 3.8 percent in 2020, representing the biggest downturn in four decades. While the economy was expected to achieve sizable growth in the 2021-2022 period, offsetting the 2020 downturn and returning to 2.5 percent growth in 2023, the recent floods and mudslides as a result of extreme weather events may impact these projections. Further, BC's unemployment rate is currently higher than 2015 levels but is forecast to improve in the following years. Government deficit spending is a key factor in the forecast economic rebound. The province was running a small surplus before the onset of the pandemic. But ramped-up

[14] Historical numbers are based on Statistics Canada and forecasts are based on TD Economics December 15th 2021 Provincial Economic Forecast report.

government spending, required to support the economy, led to a fiscal deficit of $5.5 billion in 2020–21 followed by an estimated $1.7 billion deficit in 2021–22.

Housing starts are an important variable in determining residential customer additions. As was the case in other provinces, BC's housing market survived the pandemic in reasonably good shape. As seen in Table A3-1, despite the pandemic, BC's housing starts are higher than 2015 levels, reflecting the continued housing boom fueled by record low interest rates.

Based on the Conference Board of Canada (CBOC) long-term forecast, from 2026 to 2040, economic growth is forecast to average 1.5 per cent, slightly less than the growth expected for Canada's economy as a whole[15]. Demographic issues are expected to further lead to lower housing starts over the long term as the aging population lowers the demand for new homes. Housing starts are forecast to decline from around 38,000 in 2020 to 18,000 in 2040. These long-term forecasts for both GDP and housing starts are lower than what was forecast in the CBOC's 2015 long-term forecast indicating that in the CBOC's view, BC's long-tem outlook is slightly worse than what was assumed in 2015. As for investments, according to the CBOC, once the Coastal GasLink project is completed in 2024–2025, there will likely be a limited number of large-scale projects. In addition, new emission targets under BC's climate plan may work to limit further expansion in a sector that could otherwise be a growth driver, the province's LNG sector.

In conclusion, FEI's assessment of BC's major economic indicators indicates that BC is recovering from the pandemic lows and that, with exception of the unemployment number, the 2022 forecast numbers for housing starts and GDP growth are higher than the 2015 levels. Nevertheless, the record high inflation rate, caused by government fiscal and monetary policy to boost economic growth and improve employment, and BC's challenges for long-term economic growth points to higher risk.

15 Conference Board of Canada; British Columbia's 20-Year Outlook; August 2021.

4. POLITICAL RISK

FEI defines political risk as the potential for governments or other stakeholders to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, and safety regulations. The political landscape is a significant risk factor for FEI, and is the risk category where FEI has experienced the greatest change since the 2016 Proceeding. FEI's assessment is that its political risk is significantly higher than what was assessed in the 2016 Proceeding.

Climate action goals and legislation are moving forward at a rapid pace at all levels of government. While FEI's infrastructure and energy conservation programs play a critical role in climate action, there are inherent risks to FEI's approach and how it fits into the future energy landscape within BC. Factors outside of the company's control such as public perception, political decisions, increased competition from the electricity sector supported by electrification-friendly federal, provincial and municipal policies, could hamper FEI's ability to execute on its climate goals. For example, the provincial government recently introduced the Roadmap which increases uncertainty for utilities like FEI and increases risk to utility investments and infrastructure.

The subsections below are organized as follows:

- Section 4.1 explains how increasing public concern over climate change has resulted in action by all levels of government to address these concerns, which represents a challenge to FEI's business; and
- Section 4.2 outlines climate change policies and an increase in legislation at all levels of government to meet GHG emissions reductions requirements.

4.1 *RISKS ASSOCIATED WITH CLIMATE ACTION GOALS AND EXPECTATIONS HAVE INCREASED*

As discussed below, FEI has assessed the business risk associated with climate action goals and expectations to have increased significantly.

4.1.1 Public Concern about Climate Change Is Driving Government Policy

Public opinion influences the development of public policy and increasing public concern over climate change has resulted in action by all levels of government to address these concerns. This action on climate change has created an imperative for utilities like FEI to adapt quickly.

Several polls show public attitudes supporting urgent, imperative climate action. For example:

- Polling conducted by Angus Reid in May 2021 concluded…"45 per cent of Canadians say the federal government needs to do more to tackle climate change."[16]
- Polling by Positive Energy found that climate urgency is increasing; 39 per cent of Canadians say we need to act now (an increase from 31 per cent in November 2020 and 21 per cent in June 2020)[17].
- Ipsos Reid also polled in 2020 that two-thirds of Canadians believe climate change is as serious a problem as the COVID-19 pandemic.[18]
- In a survey conducted by Clean Energy Canada, 57 percent of British Columbians support efforts to put fighting climate change at the centre of BC's COVID-19 pandemic recovery plans.

In response to public opinion, the federal, provincial and local governments are strengthening climate targets and policies. The following subsections provide more detail on how all levels of government have responded to political pressure from constituents by enacting stringent policies and net-zero targets.

4.1.2 Net-Zero GHG Emissions Future Is Required for Climate Stabilization

Achieving net-zero GHG emissions has risen in importance as climate science is increasingly suggesting that this will be required to stabilize increasing global temperatures by mid-century. In response, the federal government has introduced legislation to move to a net-zero target by 2050; in the 2020 provincial election the BC NDP pledged to move to a net-zero target as well.

A net-zero emissions future requires a substantial reduction in emissions and that any residual GHG emissions from the combustion of fossil fuels be offset by the removal of atmospheric carbon through the expansion of carbon sinks and/or carbon capture technologies. This places additional pressure on FEI to transition away from the fossil fuel that it currently delivers and creates additional risks for FEI for a number of reasons, including:

- The pathways to achieve a net-zero future in BC are not well understood. There is considerable uncertainty on the portfolio of policies, technologies and other actions that will be required to reach net-zero.
- Net-zero targets are more ambitious, requiring in many respects a step change in technology deployment and rate of reduction in fossil fuel consumption.
- Many technologies that may be required for net-zero are in the early phases of technological development.

[16] https://angusreid.org/wp-content/uploads/2021/05/2021.05.03_Climate_Change.pdf.

[17] https://www.uottawa.ca/positive-energy/sites/www.uottawa.ca.positive-energy/files/2021-1809_positive_energy_feb_populated_report_-_updated_with_tabs.pdf.

[18] https://www.ipsos.com/en-ca/news-and-polls/Two-Thirds-Of-Canadians-Think--In-The-Long-Term-Climate-Change-Is-As-Serious-Of-A-Problem-As-Coronavirus.

The uncertainty around how a net-zero energy economy can be achieved is illustrated by the Canadian Institute for Climate Choices in their report titled Canada's Net-Zero Future.[19] The report is an in-depth examination of a net-zero future for Canada to-date and concludes that there are many pathways to achieve net-zero without a defined optimal pathway.

Similarly, the International Energy Agency (IEA) recently released a report called Net-Zero to 2050[20]. The report aims to inform decision-making at all levels of government on the scale of action required to achieve net-zero and outlines whether government policy is broadly aligned with the IEA's Net-Zero Emissions pathway. Some of the key recommendations by the IEA include no investment in new fossil fuel supply projects from today, and that fossil fuel consumption shrinks by 75 per cent globally by 2050. Another recommendation is no exploration and development of new natural gas or oil resources going forward, and by 2025 there would be no gas heating equipment adopted in new buildings.

While there is broadening consensus among policymakers on the need to achieve net-zero emissions over the long-term, there is considerable uncertainty on what role the gas system will play in achieving these goals and how policymakers will utilize the gas system for a net-zero transition.

While gas infrastructure is a promising tool to reach decarbonization goals, there is a lack of awareness and acceptance of the role it could play. This creates a higher risk for FEI relative to the political risk environment at the time of the 2016 Proceeding. This higher level of risk must be managed with continued investment in research, analysis, and development of low-carbon solutions within a net-zero context, and engagement with policymakers at all levels of government and key stakeholders who inform climate change-related policy development.

4.2 *NEW ENERGY POLICIES AND LEGISLATION POSE A SIGNIFICANT CHALLENGE*

Targets and policies in response to public support for climate action are being developed at all levels of government to make meaningful progress toward GHG reduction targets, creating a challenging operating environment for FEI. There is also currently a lack of clarity within federal, provincial and local governments on the role of the gas system. This is compounded by the fast pace of legislation and policies in support of electrification. In contrast, government direction and policies that identify and consider the gas system's role in decarbonization have been slower to emerge and develop. Overall, the risk faced by FEI associated with new energy policies and legislation has increased significantly since the 2016 Proceeding.

---

[19] https://climatechoices.ca/reports/canadas-net-zero-future/.
[20] https://www.iea.org/reports/net-zero-by-2050.

4.2.1 Federal Government

Both the federal Liberal and NDP parties committed to greater effort to meet and exceed the Paris targets, including a pledge to reach net-zero by 2050. In the fall of 2020, the Liberal government announced a new climate plan to exceed its 2030 targets, signaling carbon tax increases, deep energy and climate policy reform, and significant public investment into energy transition efforts. Of significance, within the plan is a proposed carbon tax escalation of $15 per tonne per year after 2022, reaching $170 per tonne by 2030. Section 6.3.2 outlines the impact this will have on FEI's price and competitive position. Most recently, at the COP26 conference in November 2021, the federal government announced a cap on oil and gas sector emissions[21] to reach net-zero by 2050.

There are many policies and agendas that affect the timing and magnitude of risk that FEI faces. Additionally, the lack of clarity from federal and provincial policymakers on the role of the gas system in decarbonization has increased risk and uncertainty for FEI. While the solutions that FEI offers to align with a low-carbon future would assist with the federal government's goals, a lack of program support, stringent policies and favouring one solution set over others put FEI's system and ratepayers at risk. FEI's risk due to federal government policies is significantly higher than in the 2016 Proceeding. Some specific policies are discussed below.

4.2.1.1 Pan-Canadian Framework

The Pan-Canadian Framework on Clean Growth and Climate Change[22] (PCF) was Canada's first national climate plan and was released in December 2016 (after the 2016 Proceeding), marking a shift towards increased federal involvement in climate policy. The PCF has four main pillars: pricing carbon pollution, complementary measures to reduce emissions, climate change adaptation and actions to accelerate innovation. Most notably, the PCF contained measures to significantly reduce emissions in the buildings sector by making new buildings net-zero, retrofitting existing buildings, fuel switching, improving energy efficiency for appliances and equipment and supporting building codes and energy efficient housing. The PCF set an aspirational goal in 2017 that by 2035 all space heating technologies sold have a performance of greater than 100 percent efficiency. This would effectively ensure that only electric or gas heat pumps would be available for use by this time. The PCF signalled further electrification measures for the buildings sector and fuel switching from natural gas.

4.2.1.2 Net-Zero Emissions Accountability Act

The Net-Zero Emissions Accountability Act (Bill C-12) was introduced in November 2020. Were it to be adopted, Bill C-12 will establish a process to set five-year national emissions-reductions targets for the years 2030, 2035, 2040, and 2045. To inform Bill C-12, the federal government formed the Net-Zero Advisory Body, which does not include any representatives from the gas industry. This presents a risk that the role of the gas system will be absent in future net-zero goals, creating additional uncertainty and risk for FEI that solutions offered through the gas

21 https://liberal.ca/our-platform/cap-and-cut-emissions-from-oil-and-gas/.
22 https://publications.gc.ca/collections/collection_2017/eccc/En4-294-2016-eng.pdf.

system could be overlooked in the recommendations made by the Advisory Body which will set the direction for federal policy making.

4.2.1.3 Clean Fuels Regulation

The federal government published a draft of its Clean Fuel Regulation[23] at the end of 2020, which is central to the federal government's mandate to reduce GHG emissions 30 percent by 2030. The 2020 draft no longer includes the gaseous and solids streams and instead only targets liquid fuels, mainly used in the transportation sector. While the removal of the gaseous stream means there is currently no federal mandate for gas utilities to decarbonize their fuel, it also signals that there is no longer-term vision for the low-carbon solutions delivered by the gas system as part of the federal government's overall approach to climate action despite the merits of this approach to decarbonization.

4.2.1.4 Healthy Environment and a Healthy Economy Federal Climate Plan

In December 2020, the federal government released a plan titled *A Healthy Environment and a Healthy Economy*[24] (HEHE) that builds on the PCF. The current HEHE plan includes a number of measures that promote electrification of key emitting sectors in Canada.

A significant focus of federal activity has been on improving building energy efficiency for new and existing buildings. The HEHE contains measures to improve energy efficiency in buildings and work on building codes with provincial and territorial governments. This includes an investment of up to $1.5 billion over three years in energy efficient buildings. It also includes an investment of $2.6 billion over seven years to help homeowners retrofit their existing homes, build a low-emission buildings material supply chain, build a new retrofit code for existing buildings to be put into place by 2025, and build Canada's first national infrastructure assessment to undertake long-term planning towards a net-zero future.

The HEHE does not outline a specific role for the gas system to achieve its 2030 target except for expanded program spending for clean fuels, which includes renewable and low-carbon gases.

4.2.2 Provincial Government

The provincial government has intensified its effort to take climate action through a variety of policies, measures and proposals discussed below, which suggest that both electrification and decarbonization of the gas system are key strategies to meet the provincial government's climate goals. The depth and intensity of measures reflects that, while BC has made progress to reduce the carbon intensity of its economy, it is not on pace to achieve its 2030 target of a 40 percent reduction from 2007 levels. As part of its renewed effort to accelerate progress toward achieving

[23] https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard/about.html.

[24] https://www.canada.ca/en/environment-climate-change/news/2020/12/a-healthy-environment-and-a-healthy-economy.html.

its GHG emissions target, the province set sectoral targets in March 2021. These targets, set on a 5 percentage point range, represent the required emission reduction from 2007 levels by 2030 for the following sectors:

- Transportation – 27 to 32 percent;
- Industry – 38 to 43 percent;
- Oil and Gas – 33 to 38 percent; and
- Buildings and Communities – 59 to 64 percent.

Notably, FEI delivers the majority of its energy to the Industry and Buildings and Communities sectors which are also the sectors with the most ambitious targets. This places significant pressure on FEI to source affordable, reliable and low-carbon energy to continue to serve these sectors.

4.2.2.1 CleanBC Roadmap to 2030

On October 25, 2021, the provincial government released the Roadmap as an update to the 2018 CleanBC plan as part of its commitment to achieve BC's legislated GHG reduction target of 40 per cent below 2007 levels by 2030. The Roadmap articulates a plan to fully achieve this target and sets the course to reach net-zero by 2050. The Roadmap, which won an award at the United Nations COP26 climate conference at Glasgow, Scotland[25], includes ambitious measures that place FEI at the forefront of the energy transition and is anticipated to have a significant impact on FEI's customer rates, competitiveness and throughput. Amongst the key measures in the Roadmap are a number of policies that directly impact FEI including:

- An increased carbon tax which will rise to $170 per tonne by 2030;
- A GHG cap for natural gas utilities;
- A zero carbon requirement for new buildings and highest efficiency standards for space and water heating equipment by 2030[26];
- Amendments to the Low Carbon Fuel Standard to decrease the carbon intensity benchmark while adding marine and aviation fuels; and
- A 75 percent reduction in oil and gas methane by 2030.

The Roadmap identifies key priorities in regard to decarbonizing FEI's customer emissions in the buildings and communities, transportation, and industry sectors; however, its measures rely heavily on the electrification of energy end uses to reduce GHG emissions. This policy preference is demonstrated in the release of the BC Hydro Electrification Plan (see Section 4.2.2.2.2 below)

---

[25] https://news.gov.bc.ca/releases/2021ENV0068-002116

[26] This includes a requirement that all space and hot water heating equipment must meet or exceed 100 percent efficiency after 2030 which cannot be met with conventional gas equipment.

which aims to increase electrification of gas end uses and transportation and in measures such as zero carbon new construction and energy efficiency standards where gas solutions are not yet established.

The Roadmap presents substantial risk to FEI which was not present at the time of the 2016 Proceeding. FEI's political risk, due to current and pending provincial legislation, has increased significantly. Several aspects of the Roadmap are considered further below.

4.2.2.1.1 CARBON TAX

Among the measures announced in the Roadmap, the carbon price of $45 will either match or exceed the federal carbon price, which is expected to rise to $170 per tonne by 2030 with annual increases of $15 starting in 2023. The risk for FEI is that a GHGRS cap as proposed in the Roadmap would put an implicit price on carbon by limiting the supply of GHG emissions that would be allowed. If the carbon tax is also charged on gas customers then they will effectively pay a double carbon charge[27], further weakening the competitiveness of the gas system and the low-carbon solutions the gas system offers.

4.2.2.1.2 GHG REDUCTION STANDARD: EMISSIONS CAP FOR NATURAL GAS UTILITIES

Before the Roadmap, the 2018 CleanBC plan outlined a target for natural gas delivered to industrial and residential consumers to contain at least 15 percent renewable content by 2030. Displacing 15 per cent of the natural gas supply with Renewable Gas would increase the annual supply of RG to approximately 30 PJ and reduce emissions by approximately 1.5 million tonnes from natural gas delivered to customers connected to FEI's system. This made the Renewable Gas target a substantial part of the buildings emissions reduction strategy.

The province's approach was updated in the Roadmap with a cap on GHG emissions for natural gas utilities called the GHG Reduction Standard (GHGRS). The GHGRS will establish an obligation for natural gas utilities to reduce GHG emissions from energy delivered to the buildings and industrial sectors. FEI expects that compliance with the cap will be overseen by the BCUC. Enabling legislation will be developed or enhanced through amendments to the regulation that will further define how this policy will be implemented for natural gas utilities.

The move from a voluntary Renewable Gas target to a mandated GHG emissions cap is a substantial change in direction for provincial policy. While details on the GHGRS remain under development, the cap will place a stringent emissions reduction obligation on gas utilities. Compliance pathways to achieve the cap have not yet been developed; however, these pathways will be highly consequential for the overall role of natural gas utilities and for customers that rely on the energy that natural gas utilities deliver.

The GHGRS is a first in Canada, and will mandate FEI to invest in carbon saving technologies and solutions to displace natural gas consumption by 2030. The cap will be set at 6.11 Mt of CO_2e

[27] Customers will be required to pay compliance costs on the 47 percent reduction, plus the carbon tax will be paid on the remaining 53 percent.

per year for 2030, which is approximately 47 percent lower than 2007 levels[28]. The GHGRS would require a GHG reduction of approximately 5.5 Mt of CO_2e which is equivalent to displacing approximately half of the natural gas delivered by FEI.

It is anticipated that the GHGRS policy framework will enable utilities like FEI to invest in a broad set of GHG saving actions such as Renewable Gas, energy efficiency and other measures. However, it is unclear to what extent FEI will be able to maintain its customer load and how the framework will impact customer rates, how new investments and costs will undermine FEI's competitiveness, what compliance or penalty mechanisms will be applied to enforce FEI's obligation to reduce emissions and how much fuel switching from the gas system for greater electrification will impact the utilization of FEI's infrastructure.

Additionally, an emissions reduction of 61 percent by 2030 as targeted in the buildings sector as part of the GHGRS is extremely aggressive, disproportionately impacts FEI, and is more representative of a 2040 target which requires a more rapid transition in the buildings sector at greater cost and risk. For comparison, the sectoral target for buildings embedded in the GHGRS target is nearly three times the Colorado Clean Heat Standard[29]. The GHGRS was designed after Colorado's standard, which is set at only a 22 percent reduction. These impacts are explored in greater detail throughout this Appendix.

4.2.2.1.3 DIFFERENT COMPLIANCE PATHS TO ACHIEVE THE GHGRS COULD HAVE SIGNIFICANT IMPACTS ON FEI

FortisBC commissioned the Pathways Report[30] to analyze two energy pathways: a pathway primarily focussed on Electrification, as well as a Diversified Pathway which includes a mix of expanded electrification and low carbon gas that maintains a prominent role for FEI's infrastructure to achieve deep decarbonization objectives. The report demonstrates that the Diversified Pathway maintains the use of the gas system out to 2050, achieves GHG reductions in-line with the provincial government's objectives and is a more affordable, resilient and practical pathway for BC. However, significant market transformation will be required to scale the supply of Renewable Gas and deploy building envelope efficiency upgrades and efficient appliances, such as gas heat pumps and hybrid heating systems.

Whether the provincial government adopts the Diversified Pathway as its preferred approach and whether it will be fully implemented is uncertain at this time, adding risk that the decarbonization potential of the gas system will not be fully realized to achieve the goals of the GHGRS. This includes uncertainty over enabling compliance pathways to achieve the reduction and to what extent electrification will be used to advance the GHGRS. Furthermore, it is unknown whether rate impacts caused by complying with the GHGRS can continue to be competitive and affordable for customers, and whether FEI's infrastructure will continue to be fully utilized.

---

28 Representing the average sectoral reduction required for the buildings and communities and industry sectors.
29 https://leg.colorado.gov/bills/sb21-264.
30 https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf.

The challenge to reduce GHG emissions in line with the goals and timing of the GHGRS is significant and presents substantial risk to FEI. FEI will need to significantly increase the pace and scale of investments in carbon reducing solutions.

4.2.2.1.4 BUILDINGS

In the Roadmap, new carbon pollution standards are set for the BC Building Code, which include a transition to zero-carbon new buildings by 2030. The standards will be performance-based and will allow for flexible options, which include low-carbon fuels like Renewable Gas. For Renewable Gas to have a meaningful role in the buildings sector decarbonization policies, issues such as GHG reduction permanency[31] will need to be resolved. This makes new approaches such as the proposed revised Renewable Gas program submitted to the BCUC in December 2021 essential to aligning with the provincial government's GHG reduction objectives.

In addition to requiring low-carbon energy for new buildings, all new space and water heating sold and installed in BC will need to be at least 100 per cent efficient. Electric and high-efficiency gas heat pumps will be used to reach this goal and incentives for conventional gas-fired equipment will be phased out. This suggests that the provincial government sees a declining role for conventional home heating appliances in favour of gas and electric heat pump solutions. However, gas heat pumps are not yet commercially available for customers to purchase, leading to a significant risk for FEI related to the uncertain timing of gas heat pump commercialization in relation to the implementation of the 100 percent efficiency standard in 2030 and near-term phase out of incentives on conventional gas equipment. This risk is further discussed in Section 7.2 and raises significant uncertainty on the role that the gas system and gas appliances will have in the buildings sector for both new builds and retrofits.

As demonstrated above, the direction to reduce GHG emissions in new buildings is increasing in stringency and ambition. FEI is evaluating low-carbon solutions to align with this increased ambition; however, the Roadmap adds a new risk related to FEI's ability to connect new customers to its system and raises the risk of losing a large portion of new customers in the residential building sector.

4.2.2.1.5 LOW CARBON FUEL STANDARD

The BC Low Carbon Fuel Standard (LCFS) requires fuel suppliers to decrease the average carbon intensity of the fuels they supply. In the 2018 CleanBC plan, the stringency of the LCFS was doubled and the carbon intensity reduction target for gasoline and diesel rose from 10 percent to 20 percent by 2030. In the Roadmap, the carbon intensity target will be raised beyond 20 percent to 30 percent. The LCFS will also be expanded to include marine and aviation fuels, which is a positive for FEI because the inclusion of marine fuels improves the competitiveness of BC LNG. However, there is currently no detail on the timing or nature of this policy development.

[31] Permanency of GHG emissions reductions is an important issue for municipal policymakers and refers to the extent to which FEI's measures, such as RG, are voluntary in nature allowing customers to opt out of an offering over time, thereby eroding their permanence.

The increased stringency of the LCFS will increase risk for FEI's CNG vehicles as the volume of credits they generate may be significantly reduced or eliminated. This will reduce the competitiveness of CNG and LNG vehicles. While Renewable Gas will be able to generate more credits as a result of the LCFS change, there will be pressures on the use of Renewable Gas supply to meet FEI's other GHG reduction obligation through the GHGRS.

4.2.2.1.6 OIL AND GAS

The Roadmap aims to reduce methane emissions from upstream oil and gas, reduce oil and gas emissions in line with sectoral targets, advance carbon capture and sequestration and engage industrial customers in GHG reduction planning. While there are not many details on the cap on oil and gas emissions, it could potentially increase the commodity cost of gas in the province, which could make FEI less competitive.

4.2.2.2 Electrification

The Roadmap, based on the measures outlined above, is supportive of greater electrification, placing pressure on FEI to retain customers and grow its business by attracting new customers. This, in turn, can force FEI to become less cost competitive over time. The section below highlights how the Buildings Electrification Roadmap and BC Hydro Electrification Plan further aim to electrify many aspects of BC's economy, including loads currently served by FEI.

4.2.2.2.1 BUILDING ELECTRIFICATION ROADMAP

The Building Electrification Roadmap[32] (BERM) was sponsored by the provincial government, BC Hydro and the City of Vancouver and is a central strategy to decarbonize the building sector by using electrification. Some key aspects of BERM include:

- Characterizing the low cost of natural gas as a primary barrier facing BC's building sector;
- Highlighting technologies that facilitate the transition from natural gas to electricity;
- Noting Renewable Gas as another energy source that can facilitate building decarbonization; and
- Describing electric heat pumps as a means to transition out of natural gas fired appliances.

The BERM provides an analysis of the state of affairs of BC's building sector and its associated emissions, and provides recommendations that mainly revolve around using policy tools to increase the costs of natural gas to be equal to electricity costs, replacing natural gas appliances in favour of electric ones, and investing heavily in electric heat pumps. While Renewable Gas was cited as an energy source that could potentially aid in building decarbonization, the BERM points towards electrification as the main opportunity and solution for BC to reach its climate goals, creating risk for FEI.

32 https://www.zebx.org/wp-content/uploads/2021/04/BC-Building-Electrification-Road-Map-Final-Apr2021.pdf.

4.2.2.2.2 BC HYDRO ELECTRIFICATION PLAN

The Electrification Plan[33] initiated by BC Hydro was launched in September 2021 as part of its Revenue Requirements Application. The Electrification Plan proposes new programs and incentives to switch from fossil fuels to electricity in homes and buildings, transportation and industry. BC Hydro plans to spend $360 million on electrification initiatives over the next five years, of which $190 million will be used to encourage customers to switch from natural gas and diesel to electricity.

In the buildings sector, BC Hydro identified expanding residential air source heat pumps and switching from natural gas furnaces as a key strategy. While BC Hydro acknowledges that there are still barriers for building owners switching to electric heat pumps, mainly affordability, a new incentive allows customers to receive up to $11 thousand per household if they switch from natural gas to an electric heat pump. In the Industrial sector, BC Hydro also identified displacing fossil fuels and attracting new load from traditional resource industries and manufacturing.

The Electrification Plan states that electricity rates will go down for customers for the years that the Electrification Plan is in its "testing phase" between 2021-2026[34]. The Electrification Plan does not discuss the long-term costs or potential impacts of relying on electrification-only measures past 2026 and rate impacts of electrifying substantial natural gas loads and what that means for British Columbians.

4.2.2.3 Government's Use of BC Hydro to Advance Government Climate Policies

BC government policy directions and legislative tools from the last couple of years in respect of BC Hydro have affected the competitive landscape in a way that promotes electricity to the disadvantage of natural gas. In particular, government has socialized the utility's costs to strengthen BC Hydro's financial standing, and focused on policies that increase BC Hydro's load, lower BC Hydro customers' rates and increase BC Hydro's competitiveness.

The provincial government's 2019 decision to write-off BC Hydro's rate smoothing deferral account is one recent example of BC Hydro costs being transferred to taxpayers. On February 14, 2019 the BC government issued a news release stating that "as part of transitioning to enhanced oversight, government has accepted a recommendation from the review for BC Hydro to stop using the rate-smoothing regulatory account and to write off its balance to zero in 2018-19. This will limit rate increases and relieve ratepayers of the burden of directly paying off $1.1 billion in deferred costs over the next five years.[35]" The government's decision to socialize $1.1 billion of BC Hydro's costs, other things equal, reduces FEI's price competitiveness in service areas where FEI competes with BC Hydro. In addition, customers of other electric utilities in BC

---

33 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/electrification/Electrification-Plan.pdf.

34 https://www.bchydro.com/news/press_centre/news_releases/2021/rra-f23-f25.html.

35 https://news.gov.bc.ca/releases/2019EMPR0004-000231.

(such as FBC) are paying their own electric rates as well as subsidizing those of BC Hydro through taxes.

The Roadmap is another example of how the provincial government is using BC Hydro to advance its electrification policy. The Roadmap states that in order to help support and drive BC Hydro's focus on GHG reductions, the BC Government will add electrification and fuel switching to BC Hydro's mandate[36]. The Roadmap also includes various initiatives to help BC Hydro gain additional market share in space heating and water heating end-uses which will have a direct negative impact on FEI's biggest market.

Preferential tax treatment for electricity is another example. While carbon pricing, discussed in Sections 4.2.2.1.1 and 6.3.2, is government's main tax initiative to discourage the consumption of fossil fuels, the BC government provides additional preferential tax treatment for electricity to encourage electricity consumption even further.

In June 2018, the provincial government issued a news release indicating its plan to phase out the Provincial Sales Tax (PST) on electricity for commercial and industrial customers:

> To lower electricity costs for BC businesses and industries, the BC government is phasing out the provincial sales tax (PST) on electricity. Following the 50% reduction that started on Jan. 1, 2018, government will completely eliminate the PST on non-residential electricity on April 1, 2019. Residential use of electricity is already PST-exempt[37].

The elimination of the PST for electricity consumption, in addition to the increase in carbon tax on natural gas bills, further reduces FEI's price competitiveness (see Section 6.3.2) and is another sign of government support for electrification of the economy.

4.2.3 Municipal Governments

Another area of significant change since the 2016 Proceeding is the evolution of municipal policies that constrain the use of natural gas in buildings by promoting fuel switching to renewable energy sources. In the 2016 Proceeding, FEI's evidence in this regard focussed on the City of Vancouver and the Creative Energy utility in Vancouver, as the developments were largely confined to this. Since such time, boosted by the provincial government's decision to provide greater autonomy and power to local governments to address climate related challenges, municipal climate and energy policy has been evolving quickly and spread to more municipalities.

The majority of BC's local governments have signed the BC Climate Action Charter, a voluntary agreement between the BC government and the Union of BC Municipalities where each local government signatory commits to take action on climate change. Since the 2016 Proceeding, an

---

[36] CleanBC Roadmap to 2030, p. 30.
[37] https://news.gov.bc.ca/releases/2017fin0035-001987?bcgovtm=20200509_EML_NEWS_69_INFO_BSD_BCNDP_EN_ACTIVE

increased number of local governments are now taking climate action and are actively collaborating with each other to learn from best practices. For example, Metro Vancouver Regional District (Metro Vancouver)[38] has developed its own Climate 2050 Strategy (in September 2018 and revised in July 2019) which is made up of three main components: *Climate 2050 Strategic Framework*[39], to pursue a carbon-neutral region by 2050; *Climate 2050 Roadmaps*, which aim to describe the trajectory toward a resilient, low-carbon region for each sector or so-called Issue Areas[40]; and, an *Online Reporting and Communication Tool*, which aims to support Metro Vancouver and its members by showcasing best practices, background and reference materials.[41]

Metro Vancouver, in its Climate 2050 Buildings Roadmap, envisions Metro Vancouver residents living in zero emissions buildings across the region by 2050. It states that all buildings must have zero emissions in their operation, deriving all energy needs (e.g., heating and cooling) from 100 percent clean and renewable sources by 2050. In its recently published *Discussion Paper on Energy* dated April 2021, Metro Vancouver set its goal on reducing emissions to power the Metro Vancouver region with 100 percent clean, renewable energy sources. Its targets specific to this goal are reaching 30 percent renewable energy use in buildings by 2025, 55 percent by 2030 and 100 percent by 2050. The discussion paper identifies electrification as one "Big Idea" and calls for acceleration of electrification and restriction of fossil fuel supply infrastructure expansion in Metro Vancouver[42].

Another important development since the 2016 Proceeding is the declarations of climate emergencies by some of the most populous municipalities in BC[43]. Along with the declarations of climate emergency, a growing number of municipalities are using various approaches to reach their ambitious GHG reduction targets. These include effective bans on conventional natural gas equipment by requiring efficiency levels higher than 100 percent, adoption of stringent BC energy Step Code (Step Code) levels for new buildings and/or requiring the builders to meet or exceed certain GHGi targets per square metre of floor space, requiring connections to District Energy Systems (DES) and other measures such as financial and non-financial incentives for all electric options for space and water heating applications.

For instance, in January 2019, Vancouver City Council declared a climate emergency as a call to scale up Vancouver's efforts to cut carbon pollution. In April 2019, Vancouver City Council approved the Climate Emergency Response, which established six new targets (referred to as

[38] Metro Vancouver is a federation of 21 municipalities, one Electoral Area and one Treaty First Nation that collaboratively plans for and delivers regional-scale services.

[39] AQ_C2050-StrategicFramework.pdf (metrovancouver.org).

[40] Ten Climate 2050 Issue Areas are (1) Water and Wastewater Infrastructure, (2) Human Health and Well-Being, (3) Nature and Ecosystems, (4) Buildings, (5) Transportation, (6) Energy, (7) Land-Use and Growth Management, (8) Industry, (9) Agriculture and (10) Waste.

[41] Climate 2050 Strategic Framework, September 2018 and Revised July 2019, p.12.

[42] http://www.metrovancouver.org/services/air-quality/climate-action/climate2050/regional-priorities/energy/updates/Documents/FINALClimate%202050Energydiscussionpaper%20web.pdf

[43] About 20 municipalities including City of Vancouver, City of Victoria, District of North Vancouver and others have declared climate emergencies.

"Big Moves") to guide the City's efforts in response to the climate emergency. In October 2020, the City of Vancouver published its Climate Emergency Action Plan (CEAP) which provides the roadmap to achieve the Big Moves. Big Move 4, which focuses on heating and cooling in new and existing buildings, states that by 2030 the carbon pollution from buildings will be cut in half from 2007 levels. This entails setting annual carbon pollution limits for buildings.

The patchwork of stringent emissions regulation and policies at the local government level has led to a significant increase in FEI's policy risk at municipal levels that was not present at the time of the 2016 Proceeding. For instance, an increasing number of local governments are enacting policies that favour the use of electricity over Renewable Gas to lower emissions in buildings, creating a significant policy conflict with provincial measures which promote the expansion of Renewable Gas supply.

In the following sections, the major municipal level policies and their magnitude of impact are discussed in more detail.

4.2.3.1 Local Governments Have Been Granted Greater Autonomy

The provincial government is giving more regulatory authority to local governments, making them, in some instances, the de facto regulators of BC's Step Code and the pending GHGRS. This has created a patchwork of regulation which also complicates compliance and planning. Credit rating agencies like Moody's are also increasingly aware of the incremental risk that this approach can pose to utilities:

> Patchwork of regulations and agendas will affect timing and magnitude of the incremental risk. States and local governments pursue their own agendas, which have varied implications for utility companies that serve large, diversified regions[44].

At the municipal level, this is enabled by way of city bylaws and local government policies, which have resulted in significant differences in municipal policies throughout the province. The legislation continues to require all local governments to set emission reduction targets at the municipal and regional district level. These activities are expected to accelerate, and an indication of this is found in the Premier's mandate later to the Attorney General and Minister Responsible for Housing, which outlines one key platform where progress is expected: "Build on our government's work to require new buildings and retrofits to be more energy efficient and cleaner by supporting local governments to set their own carbon pollution performance standards for new buildings."[45]

This increased regulatory power at the local government level is evident with the release of the Roadmap, where the provincial government describes adding a new carbon pollution standard to

44 Moody's Investor Service, September 2020; "Sector in-depth report: Shifting environmental agendas raise long-term credit risk for natural gas investments", p. 1.

45 Eby_mandate_2020_jan.pdf (gov.bc.ca), p. 4.

the BC Building Code, supporting a transition to zero-carbon new buildings by 2030. Local governments will serve as pilots for future province-wide requirements. The adoption of the carbon pollution standard into the BC Building Code will pave the way for all new buildings to be zero-carbon by 2030, which in the long-term could potentially improve the current patchwork of regulations with a single baseline standard across the entire province. However, it is FEI's understanding that, in the interim, the carbon pollution standard will provide local governments with the regulatory authority and autonomy to adopt Greenhouse Gas Intensity (GHGi)[46] targets for buildings under their jurisdiction. In 2023, the provincial government will review progress and start phasing in provincial regulations over time. In the meantime, local governments will seek to implement their own standards which are expected to be inconsistent across the province.

As shown in Table A4-1 below, the adoption of GHGi targets at the local government level has already resulted in a complex and diverse set of regulations across the province. The implementation of GHGi levels, and the range of targets that have been set (from 6 $kgCO_{2e}/m^2$, to 1 $kgCO_{2e}/m^2$) vary substantially. Municipalities may adopt a GHGi regulation for the entirety of their geographic bounds, as seen in the District of North Vancouver, but limit the application of such regulation to certain building types or sub-building types. Similarly, GHGi requirements may be set at the permit level for a specific home or development, or may be required via a rezoning application. In some cases, municipalities may use a combination of one or more of these mechanisms to effect the desired GHG reduction outcome. Therefore, there is no consistency in approach or adoption across FEI's service territory, which makes creating a consistent strategy to meet these inconsistent targets particularly challenging.

Table A4-1: Sample List of Local Governments and their Low Carbon Energy System (LCES) Targets

Local Government	Building Energy Requirement	Types of Buildings Impacted	Effective Date
District of West Vancouver	Either Step 5 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Single family, townhouse and other Part 9[47] residential buildings	February 2021
	Either Step 5 or Step 2 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 9 Detached secondary suites	
	Either Step 4 or Step 2 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 3[48] residential Multi-family and apartment buildings.	
District of North Vancouver	Either Step 5 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 9 Single family home, coach house, smaller townhouse.	July 2021
	Either Step 4 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 3 Residential Larger multi-family and apartment projects	

46 GHGi is the total annual GHG emissions from all the energy use for the operation of a building, per square metre per year. It is calculated by multiplying the total amount of a building's energy use in one year by the associated emission factor for that energy source, and dividing it by the building's gross floor area.

47 Part 9 refers to housing and small buildings (that are up to three storeys in height, and an area not exceeding 600 m^2 in area).

48 Part 3 refers to commercial and MFD that exceed three storeys or exceed 600 m^2 in area.

Local Government	Building Energy Requirement	Types of Buildings Impacted	Effective Date
	Either Step 3 or Step 2 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 3 Commercial, Office and Retail buildings	
City of North Vancouver	Either Step 5 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Newly constructed Part 9 residential buildings	July 2021
City of Burnaby	Either Step 3 or Step 2 with a Low Carbon Energy System (6 $kgCO_2e/m^2$)	Rezoning applications for Part 3 residential and commercial buildings	July 2019
City of Surrey	Either Step 3 or Step 2 with a Low Carbon Energy System (6 $kgCO_2e/m^2$)	Part 3 Residential new construction	April 2019
	Either Step 4 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 3 Residential new construction	2023-2024
City of Richmond	Either Step 3 or Step 2 with a Low Carbon Energy System (6 $kgCO_2e/m^2$) or $\leq$ 1.2 tCO_2e / year	Part 9 Single family dwellings and duplexes, townhomes and apartments	December 2020
	Either Step 3 or Step 2 with a Low Carbon Energy System	Part 3 Residential Buildings more than 6 stories or non combustible construction	January 2021
	Either Step 4 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$) or $\leq$ 0.6 tCO_2e / year	Part 9 Single family dwellings and duplexes, townhomes and apartments	January 2022
	Either Step 5 or Step 4 with a Low Carbon Energy System (3 $kgCO_2e/m^2$) or $\leq$ 0.6 tCO_2e / year	Part 9 Single family dwellings and duplexes, townhomes and apartments	January 2025

The definition of the LCES, shown in the above table, is also inconsistent across municipalities, which can further complicate compliance for builders and developers, and challenge FEI's ability to address these requirements in a consistent manner. For instance, as presented in the table below, the City of Port Moody's LCES definition mandates equipment efficiency factors that are not offered in any commercial or pre-commercial end-use natural gas technology and thus supports fuel switching as their primary objective. Such specification forces the homeowners and builders to refrain from connecting to a natural gas energy source, losing the opportunity to use Renewable Gas and creating a policy conflict with provincial measures to expand Renewable Gas supply.

Table A4-2: Various Definitions of the Low Carbon Energy Systems Used by a Sample of Municipalities

Municipality	Low Carbon Energy Systems Definition
District of North Vancouver	A building that uses primarily low carbon energy sources to provide heating, cooling, and hot water for a building, and has a total modelled greenhouse gas intensity of no more than 3 $kgCO_{2e}/m^2/yr$.

Municipality	Low Carbon Energy Systems Definition
Surrey	A highly efficient, professionally operated and maintained mechanical system that supplies a building's space, heating, cooling and domestic hot water heating demand primarily from renewable energy sources, at a carbon intensity that is low enough so that when applied to modelled building energy use, the development satisfies the City's defined GHG limits. The City's District Energy System for Surrey City Centre is considered an LCES.
Richmond	A building's space heating, cooling, and domestic hot water heating mechanical system that is supplied with energy through either a connection to city-owned district energy system or, an on-site energy supply equipment designated to meet a minimum of 70% of building annual heating, cooling, and domestic hot water energy demand from a renewable energy source.
Port Moody	A professionally designed and maintained, highly efficient mechanical system that supplies a building's space heating, cooling, and domestic hot water heating demand primarily from renewable energy sources, and meets defined greenhouse gas intensity (GHGi) limits of 6 $kgCO_{2e}/m^2$/year and a coefficient of performance (COP) greater than 2.

In summary, increasing autonomy of local governments to set emissions reduction targets will limit energy choices for customers and create unequal access to conventional and Renewable Gas service in FEI's service territory. For instance, a new building in a municipality with a GHGi target will not have access to FEI's conventional natural gas service, while another new building across the street in a different municipality without a GHGi target may be able to use conventional natural gas. Similarly, the efficiency requirements in Port Moody preclude the use of gas equipment entirely whereas neighboring municipalities have not adopted this stringent standard.

The move towards a decentralized approach to address climate change can also affect FEI's existing customers. Municipalities' responsibilities are limited to their geographical boundaries. Municipal governments are responsive to their own constituents and typically do not consider the wider public interest discussions with regards to energy choice, energy security or affordability in other regions of the province. The push by some municipalities in large and high-density regions, such as the Lower Mainland, to electrify the building sector will eventually impact energy prices for customers in other parts of the province.

4.2.3.2 Local Government Policies for the New Construction Market

As discussed in Section 7.3.1 and corroborated in the excerpt below from the City of Vancouver's CEAP, the high turnover rate of buildings in BC means the focus on new construction is often the first step taken by local governments to reach the net zero targets set by various municipalities:

> The strategy to transition off of fossil fuels in existing buildings starts with continuing to implement Vancouver's Zero Emissions Building Plan for new construction because approximately 40% of buildings existing today will be replaced with new buildings by 2050. From there, the strategy will build on the

successes of the Zero Emissions Building Plan and the BC Step Code for new construction, adapting the approach to the challenges of existing buildings.[49]

In alignment with the provincial government's policies in the building sector, local governments are pursuing aggressive emission reduction targets in the new construction market. To achieve these targets, local governments use two main policy tools in their capacity: (i) setting emission limits per square metre (GHGi targets) by adopting higher levels of the Step Code along with LCES; and (ii) using financial and non-financial incentives to encourage low-carbon solutions which usually are focused to promote electricity-only options and to deter connection to the natural gas network. Each of these solutions is discussed further below.

4.2.3.2.1 GHGI TARGET LIMITS FOR NEW CONSTRUCTION

A number of local governments have adopted the Step Code along with a GHGi[50] target for new construction. As explained in Section 7.2, the Step Code is a provincial building code that provides the tools for municipalities to adopt a higher level of energy efficiency in new construction that goes above and beyond the requirements of the BC Building Code. Local governments can reference the Step Code in a policy, program or bylaw, requiring that builders comply with the Step Code for the new construction project. In addition to the Step Code, some local governments have begun implementing their own GHGi targets for new construction (as set out in the Table A4-2 above). The addition of GHGi targets, in conjunction with Step Code performance targets, means that only an energy source with lower carbon emissions, such as electricity or Renewable Gas[51], can be used in new construction.

Municipal GHGi targets limit FEI's ability to serve new homes and buildings using conventional natural gas. Some of the common current GHGi target levels added to the Step Code and their impact on gas appliance use are set out in the table below.

Table A4-3: Common Examples of GHG Targets for New Single Family Homes

GHGi Levels	Natural Gas Appliance Use to Meet Target
6 $kgCO_{2e}/m^2$	Domestic hot water only or convenience gas appliances only such as fireplace, cooktop and/or BBQ
3 $kgCO_{2e}/m^2$	Convenience gas appliances only such as fireplace, cooktop and/or BBQ. No space or water heating.
1 $kgCO_{2e}/m^2$	No gas appliances.

[49] City of Vancouver Climate Emergency Action Plan (October 2020), page 42.
[50] Total greenhouse gas emissions associated with the use of all energy utilities on site. The unit of measure is in $kgCO_2e$ /m^2year.
[51] While the carbon intensity of Renewable Gas is low enough to meet the Step Code and municipal GHGi targets, Renewable Gas currently cannot be used to meet these building requirements due to its lack of permanency with FEI's existing program offerings. The building would need to stay with Renewable Gas for its lifetime in order for the GHG emissions target to be met. However, a customer in FEI's current voluntary Renewable Gas Program can opt out of the program at any time, meaning that FEI's current Renewable Gas Program does not provide the requisite certainty that GHGi targets will be met.

For a relative comparison, the GHGi baseline for new construction using conventional natural gas lies in the range of approximately 11 to 27 kg CO_{2e}/m^2 for homes.

Although a natural gas appliance can meet the 6 kg CO2e/m2 target described in Table A4-3 above, FEI's experience shows that a builder or developer may choose not to use gas simply due to the added cost and inconvenience.[52] The likelihood of builders and developers using gas is consequently much lower in municipalities with GHGi targets.

As shown in Table A4-4 below, many municipalities in the Lower Mainland have already adopted this approach. The table below provides the building energy and emissions requirements for the City of Vancouver as an example, where the City of Vancouver has taken the approach of being specific in energy use measures.[53] Furthermore, the City of Vancouver is requiring zero emissions heating and hot water equipment as per the Vancouver Building By-law in new one to three storey residential buildings from January 1, 2022.[54]

Table A4-4: Building Energy and Emissions Requirements for the City of Vancouver

Policy / Bylaw	Building Energy Requirement	Types of Buildings Impacted	Effective Date
Vancouver Building Bylaw[55] **(June 2021)**	TEUI = 110 kWh/m^2, TEDI = 25 kWh/m^2 5.5 $kgCO_2e/m^2$	Residential occupancy Low-Rise (Up to 6 storeys), except Hotel and Motel	June 1, 2021
	TEUI = 120 kWh/m^2, TEDI = 30 kWh/m^2 6 $kgCO_2e/m^2$	Residential Occupancy High-Rise (over 6 storeys), except Hotel and Motel	
	TEUI = 140 kWh/m^2, TEDI = 20 kWh/m^2 8 $kgCO_2e/m^2$	Hotel and Motel occupancies	
	TEUI = 120 kWh/m^2, TEDI = 20 kWh/m^2 3 $kgCO_2e/m^2$	Personal Business, and Mercantile occupancies	
	TEUI = 100 kWh/m^2, TEDI = 20 kWh/m^2 3 $kgCO_2e/m^2$	Office occupancies	

52 Builders and developers typically do not install gas piping for just one or two gas appliance(s) due the additional cost to install the natural gas piping. In addition, due to the combustion nature of gas appliances, these appliances require venting to the outside, which again incurs additional costs to ensure that there is not inward or outward air leakage through additional leakage points or areas in the building envelope. For the builder, minimizing air leakage is a preventive measure to meet the airtightness levels of the Step Code.

53 Total Energy Use Intensity (TEUI) is a measure of total energy required to operate a building and is used to reduce the operational energy required by new buildings, as quantified on an annual basis. It includes all energy uses that are required to operate a building, including: space heating, lighting, air conditioning, heating hot water, and other end uses Total Energy Demand Intensity (TEDI) measures the thermal energy (energy in the form of heat) used by a building for space conditioning and for conditioning of ventilation air, during normal operations. TEDI is a subset of TEUI.

54 https://vancouver.ca/green-vancouver/zoning-amendments-to-support-climate-emergency.aspx.

55 https://vancouver.ca/files/cov/vbbl-part-10-unofficial-wording-effective-june-1-2021.pdf.

Policy / Bylaw	Building Energy Requirement	Types of Buildings Impacted	Effective Date
Vancouver Building Bylaw[56] **(Jan 2022)**	TEUI Varies with conditioned area TEDI = 20 kWh/m^2 3 $kgCO_2e/m^2$	Residential Buildings of 1 to 3 Storeys, and Houses (excluding Hotels/Motels)	January 1, 2022

4.2.3.2.2 INCENTIVES FOR GHG EMISSIONS REDUCTION IN NEW CONSTRUCTION

Local governments also rely on "incentives" for builders to reduce emissions in new construction. Similar to GHGi targets, approaches differ between municipalities and may be limited to specific projects or apply to municipalities as a whole.

FEI provides two publicly available examples of a municipality incentivizing developers to use a renewable energy (rather than natural gas). However, there are many more instances where a developer, through the zoning negotiation process is deterred from installing natural gas service.

- **City of Surrey**: In May 2021, the council for the City of Surrey approved a Zero Carbon Incentive to be applied to new buildings built in the Darts Hill Neighbourhood. The incentive is intended to encourage the construction of zero carbon operation buildings. The Zero Carbon Incentive allows for additional densities measured in Floor Area Ratio (FAR), or Units Per Hectare (UPH). To qualify for the incentive, buildings must have 100 percent of the operational energy needs of the site and building met with non-polluting energy, including heating, hot water, and cooking, and the building must not be connected to a fossil fuel supply grid. This is in addition to any Step Code and City of Surrey energy and sustainability provisions already in effect.[57]
- **District of Squamish:** On April 20, 2021, the District of Squamish adopted a Low Carbon Incentive Program Bylaw to encourage the construction of buildings that use low carbon energy sources, such as electricity, rather than high carbon energy sources, such as fossil fuels. The focus of the energy use is ongoing operations, most notably space and water heating appliances, such as furnaces or hot water tanks. The Low Carbon Incentive would apply community-wide to all new residential developments within certain zoning. The proposed incentive structure is to establish a new base maximum floor area ratio in the subject zones that is one third of the existing maximum density. This reduced density would be the density that could be achieved for buildings that use higher carbon energy sources, such as natural gas powered furnaces or hot water tanks. Developments that utilize low carbon energy sources could achieve a bonus maximum floor area ratio, which would be the equivalent of the current density. Given the significant density bonus for low carbon development, it is expected that most builders would utilize low carbon energy

[56] https://vancouver.ca/files/cov/vbbl-part-10-unofficial-wording-effective-jan-1-2022.pdf.
[57] https://www.surrey.ca/sites/default/files/media/documents/DartsHillNCP.pdf.

sources[58], such as electricity to meet the District's requirements and gain the added floor area ratio.

In addition to a direct financial impact on developers, city planners exert influence on builders to conform to local government policies (whether adopted in a bylaw or other policy). This is primarily achieved by streamlining permitting process for electric-only options which will have the same effect. For instance, as stated in the City of Vancouver's CEAP report, the streamlined permitting process for standard electric heat pump installation is one of the key measures used to incent adoption of electric heat pumps:

> Overly complicated and restrictive permitting requirements for standard heat pumps installations is identified as a key barrier to early owner action in the forthcoming BC Building Electrification Road Map. Of particular importance in the near-term will be to establish a simple, consistent and low-cost process for low-carbon retrofits, focused on simplifying the process for installing an electric heat pump. In 2020, the City took a number of steps to start to address this issue, including:
>
> - A new page dedicated to electric heat pump permitting on the City of Vancouver website.
> - A revised, simplified bulletin for low-rise housing. If an installation meets specific criteria, the project only requires an online electric permit.
> - A public-friendly "Neighbourly Noise Guideline" to help owners and contractors select and install a quiet, hassle-free system.
>
> Additional steps that will be taken over the next year include: 1) establishing a low-cost, flat fee for any heat pump permit, and 2) streamlining the heat pump permit process for pad mounted residential heat pumps.[59]

From a practical standpoint, as developers' primary objective is to garner the best return on their construction project, any request that could either add to their cost (direct financial impact) or delay the approval of permits (indirect financial impact) will motivate a developer to take the action required of them as stipulated by the local government. The effect of the policy or bylaw is that it impedes the ability of customers to choose gas as their energy source and prohibits FEI from connecting the new customer.

4.2.3.3 Reducing Emissions in Existing Buildings

FEI's existing customers are also affected by the regulations and other policies of local governments requiring reductions in their emissions profile. An example is the City of Vancouver's

[58] https://squamish.ca/yourgovernment/projects-and-initiatives/2020-zoning-bylaw-update/low-carbon-incentive/

[59] City of Vancouver Climate Emergency Action Plan (October 2020); Appendix J, Page 25 of 79.

CEAP from October 2020 which aims to cut the carbon pollution from building operations in half from 2007 levels by 2030. This is to be accomplished by requiring a switch from gas-fired space heating and hot water systems to renewable energy:

> Similar to Vancouver's approach for new buildings, we will set annual carbon pollution limits for most existing buildings that decrease over time. This means a maximum amount of fossil fuels a building can use in its operations. This regulatory approach provides a clear signal for trades to invest in training, suppliers to begin sourcing needed systems, and for building owners to start long-term planning toward zero emissions. It also signals the need for supportive policies and programs to the provincial government, BC Hydro, FortisBC, district energy utilities, and the B.C. Utilities Commission.[60]

This policy comes into effect for existing large office and retail buildings and detached homes in 2025. Starting in 2025, carbon intensity limits (kg CO_{2e}/m^2 /year) will incrementally decrease to zero over time before 2050 on large commercial office and retail buildings. Prescriptive requirements or carbon limits for other building types will be required in 2030.[61]

As a step to reduce emissions in existing homes, the City of Vancouver is encouraging existing gas customers to replace their residential gas appliances reaching end of life with electric equivalents such as heat pumps. Streamlining the permitting process for electric-only option retrofits (installation of electric heat pumps) is also used as another tool to encourage electrification of the existing buildings:

> The City will remove the energy upgrade requirements in Part 11 (Existing Building Alterations) of the Vancouver Building By-law that are triggered when a building owner/tenant applies for a building permit to undertake renovations in an existing building. Removing these requirements will result in a reduction in permit application and processing times, as well as reduced costs for building owners and tenants. This will eliminate a barrier faced by commercial tenants who must coordinate renovations with both building owners/managers and the City. Removing the Part 11 energy upgrade requirements will also simplify the permitting process for owners of residential ground-oriented dwellings.[62]

As well as streamlining the permitting process for rental and non-market housing that switch to electricity:

---

60 City of Vancouver Climate Emergency Action Plan (October 2020), p. 43.
61 https://council.vancouver.ca/20201103/documents/p1.pdf.
62 City of Vancouver Climate Emergency Action Plan (October 2020), Appendix J, page 25 of 79.

> … the City will streamline permitting for energy retrofits and heat pumps, and remove the current energy upgrade requirements for unrelated work so that City processes are not a barrier.[63]

Another example is the City of Burnaby's strategy for existing buildings. The City of Burnaby's "Zero Emission Building Retrofit" big move aims for existing buildings in the city to transition to low-carbon energy sources for space and water heating by 2050. It involves an update to the Heating System Permit requirement using a stepped transition approach to heat pumps or other renewable energy systems. In addition, the City of Burnaby is exploring additional policy tools and developing a retrofit strategy. By 2025, the transition from gas furnaces to heat pumps will be a requirement for heating and hot water system upgrades.[64]

From 2016 and onwards, a number of other local government councils have approved climate action plans to tackle carbon emissions in existing buildings:[65]

- City of Victoria
- City of North Vancouver
- District of West Vancouver
- City of Port Moody
- City of New Westminster
- Resort Municipality of Whistler
- District of Squamish
- City of Victoria
- District of Saanich

FEI is planning to significantly increase its Renewable Gas supply and promote the use of gas heat pumps in the future to address these policies. However, there is still considerable risk and uncertainty around technology commercialization, regulatory support from the BCUC, and policy support and alignment amongst all levels of the government; all of these are required for FEI to effectively execute on these plans.

4.2.3.4 Municipal Policies Beyond the Building Sector

Given the provincial support for more local climate policies, some local governments are starting to target or expand their regulation of air emissions. The new air quality requirements and fees introduced by Metro Vancouver are one recent example. Metro Vancouver exercises its jurisdiction over air emissions in its territory through its air quality by-law and associated fees bylaw. In October 2021, Metro Vancouver (i) introduced a new fee structure such that existing

[63] City of Vancouver Climate Emergency Action Plan (October 2020), p. 135.
[64] https://pub-burnaby.escribemeetings.com/filestream.ashx?DocumentId=47477.
[65] The list only includes the local governments that FEI is aware have climate actions plans, and is not necessarily exhaustive.

fees and fees for newly specified air contaminants increase significantly over time; (ii) increased application fees for permits, approvals and amendments, and (iii) increased administrative and emission fees for regulated facilities (including boilers and process heaters). Under the new fee structure, fees related to methane emissions begin in 2022 at $180 per tonne and increase to $1,120 per tonne by 2025. The removal of a maximum application fee, in combination with an increase in annual fees and the addition of fees for specific air contaminants increases costs for assets requiring a Metro Vancouver air discharge permit. These assets include FEI's Tilbury LNG facility, compressor stations and biogas upgrader facilities.

5. INDIGENOUS RIGHTS AND ENGAGEMENT RISK

FEI defines Indigenous Rights and Engagement risk as the potential for governments to negatively impact utility operations through policy legislation and/or regulations concerning Aboriginal rights and title or by Indigenous groups to intervene directly in the utility regulatory process or by asserting Aboriginal rights and title. FEI has made Indigenous Rights and Engagement risk its own risk category (instead of being one of the risk factors under Political Risk in the 2016 Proceeding) to reflect the increasing significance of these considerations for FEI's overall business.

FEI faces an elevated level of business risk related to relationships with Indigenous groups in BC relative to the time of FEI's 2016 Proceeding. This elevated risk is based on the evolving nature of the Crown's relationship with Indigenous groups, developments in reconciliation in Canada, significantly increased expectations among Indigenous groups, and legal claims related to Aboriginal rights and title. Specifically:

- Section 5.1 explains the operating complexity created by the number and diversity of Indigenous Groups in BC.
- Section 5.2 explains that, with significant legislative and regulatory changes, expectations regarding reconciliation and free, prior and informed consent (FPIC) have significantly increased (with differing perspectives on the content of FPIC), including, and in particular, in regulatory processes. This has added further uncertainty, risk and cost for FEI in developing and maintaining relationships with Indigenous groups, the development of new projects and ongoing operations and maintenance of FEI's infrastructure.
- Sections 5.3 and 5.4 discuss litigation risk and the risk associated with social licence concerns and protests, respectively, which are also greater.

5.1 *NUMBER AND DIVERSITY OF INDIGENOUS GROUPS IN BRITISH COLUMBIA CREATES OPERATIONAL COMPLEXITY FOR FEI*

Aboriginal and treaty rights (collectively, Indigenous rights) are expressly recognized and affirmed by section 35 of the *Constitution Act, 1982*. With respect to Indigenous rights, two factors differentiate BC from elsewhere in Canada: 1) the number of First Nations in BC; and 2) un-resolved issues around Aboriginal title in most of the province.

BC has a larger number of First Nations compared with the rest of Canada. There are approximately 200 First Nations in the province which accounts for nearly one-third of all First Nations in the entire country.[66] Indigenous groups in BC are culturally diverse, each with a unique history, culture and relationship with the Crown.

[66] About British Columbia First Nations (aadnc-aandc.gc.ca).

Most land in BC is not subject to treaty (the land is unceded), and most Indigenous groups in BC are not signatories or adherents to a treaty (historic or modern) unlike in most other provinces. Most of FEI's operations are in areas not covered by treaty, meaning that these areas are subject to assertions of Aboriginal title and may be subject to legal claims for title in the future. However, FEI also has some operations in treaty areas.

Treaties assist in delineating rights of the signatory Indigenous group. Since most Indigenous groups in BC are not treaty signatories or adherents, there are a significant number of outstanding claims to Aboriginal title and rights across the province. Further, most of BC is covered by overlapping claims of title from different Indigenous groups.

The overlap in asserted Indigenous rights, including title, means that the Crown and proponents are often required to consult and, if necessary, accommodate several Indigenous groups for a project. The number of Indigenous groups to be consulted can increase substantially for linear projects like pipelines or transmission lines. For example, for much of the Lower Mainland and Fraser Valley, where FEI has significant operations, the overlap can be upwards of dozens of Indigenous groups for a single project.

In addition to these two factors, Indigenous groups may also have varying forms of governance systems. Traditional government systems may exist in parallel to governance by elected band councils under the *Indian Act*, the *First Nations Elections Act,* modern treaties and self-government agreements. Some Indigenous groups also choose to organize themselves and operate as Tribal Councils or stewardship alliances. The complexity of understanding the relationship amongst and engaging with multiple or conflicting governance systems can be seen in the example of the Wet'suwet'en internal conflicts regarding the Coastal GasLink project in which the band councils had reached agreements with the proponent but many of the hereditary chiefs did not support the project. These conflicts are causing delays to the project and have required the procurement of an injunction to clear the ongoing blockades.[67] Further, where multiple governance systems exist, this can substantially increase the number of Indigenous groups to be consulted for a project.

Additionally, Indigenous groups are participating in regulatory and governmental processes (including BCUC processes) with increased regularity and this greater involvement can affect the time and cost to FEI to obtain regulatory approvals.

While the number of First Nations and unresolved issues around Aboriginal title remain relatively unchanged since the 2016 Proceeding, the legal framework in BC, including the adoption of the UN Declaration on the Rights of Indigenous Peoples including requirements for seeking the free, prior and informed consent of Indigenous Peoples before proceeding with project development, has changed and has increased expectations with respect to Indigenous consultation and

[67] *Coastal GasLink Pipeline Ltd. v. Huson*, 2019 BCSC 2264, paras. 53-68; Wet'suwet'en elected chiefs reject deal struck between government and hereditary chiefs | Vancouver Sun; Minister's statement on Coastal GasLink project | BC Gov News.

accommodation, involvement in decision-making and seeking and obtaining consent. These changes are described in detail below.

5.2 SIGNIFICANT LEGISLATIVE AND POLICY DEVELOPMENTS SINCE 2016

There have been significant legislative and policy developments in this area since the 2016 Proceeding, described below, that have broad impacts on FEI's business.

5.2.1 BC Has Passed Legislation to Give Effect to the UN Declaration of the Rights of Indigenous Peoples

In November of 2019, the province passed into law the *Declaration on the Rights of Indigenous Peoples Act* (DRIPA)[68] and in June 2021, the federal *United Nations Declaration on the Rights of Indigenous Peoples Act* (UNDRIP Act) became law. DRIPA and the UNDRIP Act, provide for BC and Canada's laws (respectively) to be brought into alignment with the UN Declaration on the Rights of Indigenous Peoples (Declaration)[69] and the development of action plans to meet the objectives of the Declaration.[70]

BC released its draft action plan in June 2021 which identifies actions for 2021-2026 including co-developing other agreements (whether modern treaties, self-government agreements or others); co-developing strategic-level policies reflecting collaboration and cooperation on stewardship of the environment, land and resources; and engaging First Nations to identify and support clean energy opportunities related to the BCUC Inquiry on the Regulation of Indigenous Utilities.[71]

At this point, the federal action plan has not been developed and the priorities for that plan are unknown. However, the legislative review and action plans of both governments may result in amendments to provincial and federal legislation or policy which may impact FEI's operations.

DRIPA also empowers the provincial government to enter into decision-making agreements with Indigenous groups. Such agreements could require the exercise of statutory power of decision jointly by an Indigenous governing body and the BC government or the consent of an Indigenous governing body before the exercise of a statutory power of decision.[72] The draft BC action plan identifies entering into such decision-making agreements and seeking all necessary legislative amendments to enable the implementation of such agreements to be one of the focuses for the years 2021-2026.[73] BC is in the process of negotiating its first DRIPA consent-based decision-making agreement for the environmental assessment processes for two mining projects.[74] The

68 S.B.C. 2019, c. 44 (*DRIPA*).
69 UNDRIP_E_web.pdf.
70 DRIPA, ss. 3 snd 4.
71 Declaration_Act_-_Draft_Action_Plan_for_consultation.pdf (gov.bc.ca).
72 DRIPA, s. 6.
73 Declaration_Act_-_Draft_Action_Plan_for_consultation.pdf (gov.bc.ca).
74 https://news.gov.bc.ca/releases/2022PREM0034-000899.

Errata dated October 20, 2022

potential for BC to enter into such agreements with respect to the permitting or assessment of FEI projects adds uncertainty to FEI's operations, such as delays in obtaining project approvals.

Both DRIPA and the UNDRIP Act have raised questions and differing perspectives as to the meaning of FPIC in the Declaration and what obligations may exist with respect to seeking consent from Indigenous groups. At this point, neither DRIPA nor the UNDRIP Act include a definition of consent or FPIC. Many Indigenous groups assert that FPIC requires that consent be obtained from Indigenous groups for a project to proceed. The conflicting perspectives on FPIC's meaning have created new risks for FEI, including cost escalation, project delays, uncertain timelines and risks that authorizations may be challenged where decisions are made without the consent of Indigenous groups.

Further, BC's "Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples" include that meaningful engagement aims to secure FPIC when BC proposes to take actions which impact Indigenous peoples and their rights, and identifies that BC will look for opportunities to build processes and approaches aimed at securing consent and mechanisms to build deeper collaboration and consensus.[75] The draft DRIPA Action Plan includes as an action for 2021-2026, the finalization of the Draft Principles.[76] The development of such processes and mechanisms may impact the method and timing for obtaining project approvals.

5.2.2 Legislation Relevant to FEI's Operations Is Being Amended to Align with the Declaration

In BC, legislation related to project permitting is being adopted to align with the Declaration. For example, the new *Environmental Assessment Act* (*EAA*),[77] which was brought into force in December 2019, introduces changes to the environmental assessment (EA) process in BC to incorporate the concept of FPIC. Under the previous EAA,[78] the provincial government would inform the proponent of which Indigenous groups required consultation based on strength of claim. Under the new EAA, Indigenous groups can self-select which project assessments they wish to participate in as a Participating Indigenous Nation. The EAA also includes that the Environmental Assessment Office (EAO) may establish a tariff of costs to be paid by proponents to participating Indigenous nations for their participation in the EA process.[79] The Crown and proponent may also have consultation obligations with Indigenous groups which do not identify as Participating Indigenous Nations but whose Indigenous rights may be impacted. These changes could significantly increase FEI's engagement and consultation obligations with Indigenous groups in EAs.[80] As this process is still new, there is little guidance from the EAO as to how this change to the engagement process under the new EAA will affect EA applications. However, the Tilbury Phase 2 LNG Expansion Project (which is not a linear project) is in the new

[75] Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous People (gov.bc.ca).
[76] Declaration_Act_-_Draft_Action_Plan_for_consultation.pdf (gov.bc.ca), action 2.2.
[77] S.B.C. 2018, c. 51.
[78] S.B.C. 2002, c. 43.
[79] EAA, s. 48.
[80] EAA, s. 14.

EA process (concurrently with the federal impact assessment process). In this process, FEI is engaging with 42 Indigenous groups including 15 registered Participating Indigenous Nations.[81] This is a significant increase from the number of nations which would have been consulted under the former EAA.

Under the new EAA, the EAO must seek to achieve consensus with the Participating Indigenous Nations at various stages of the EA process.[82] The EAA also requires that at certain stages, the consent or lack of consent of Participating Indigenous Nations be considered: namely, in deciding whether to proceed with an assessment and the Minister's decision whether to issue an environmental assessment certificate. If the Minister's decision is contrary to the consent or lack of consent of the Participating Indigenous Nation, the Minister must offer to meet with the Participating Indigenous Nation and attempt to achieve consensus.[83] Additionally, the EAA provides for the ability for Participating Indigenous Nations to undertake an assessment of the impacts of the project on their rights within the environmental assessment process or substitute their process for aspects of the EA process.[84]

In addition, the new EAA process includes a project notification requirement which now requires a threshold range rather than specific threshold. The notification for projects which are within 15 percent of the thresholds requires the EAO to actively engage with Indigenous Nations and the public, and therefore creates a direct channel for stakeholder and Indigenous Nations to pressure the Minister to exercise their authority to designate a project as reviewable under the EAA. While the Minster previously had the authority to designate a non-threshold project as reviewable, this notification process may be considered as creating an increased likelihood of such a designation being made.[85]

Similar to the changes in the EAA, the federal *Impact Assessment Act* (IAA) requires that an impact assessment consider any assessment of effects conducted by an Indigenous governing body provided for the project being assessed and provides a mechanism for the Minister to enter into agreements with Indigenous governing bodies regarding the assessment of effects.[86]

These provisions in the EAA and IAA may increase the cost of Indigenous engagement within the EA process, increase the risk of delays and of legal challenges related to consensus-seeking and consent. These risks increase the pressure on FEI to enter into agreements with more Indigenous groups regarding projects, regardless of their strength of claim, due to their potential influence on regulatory processes.

Although not all FEI's projects or operations require an EA (Reviewable Projects Regulation[87]), the EAA provides an opportunity for a person (including an Indigenous group) to apply to have a

81 EAO Readiness Decision Report Tilbury Phase 2 LNG Expansion Project.
82 EAA, see for example ss. 16, 19, 27, 28, 29, 31 and 32.
83 EAA, ss. 16 and 17.
84 EAA, ss. 19(4) and 41.
85 Project_notification_policy_v12_sept_20_2021_-_final.pdf (gov.bc.ca).
86 IAA, S.C. 2019, c .28, s 1, ss. 22(1)(q) and 114.
87 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/243_2019#section3.

not otherwise reviewable project designated as a reviewable project.[88] These changes to the EAA may significantly increase the timelines and costs for a project that would have otherwise not been reviewable through the EA process.

Other legislation relevant to permitting has also been amended with the Declaration in mind including the *Heritage Conservation Act* which includes expanded powers to the Minister to amend, suspend or cancel permits and require reporting for the discovery of objects with heritage value.[89] This increases the risk of operating for FEI, particularly as it relates to extended timelines.

BC has also introduced amendments to the *Interpretation Act* to include interpretive directions that BC legislation must be interpreted as not abrogating or derogating from Indigenous rights and must be read so as to be consistent with the Declaration.[90] At this point, it is unclear what impact such amendments may have but there is the potential that such amendments may change how regulatory bodies interpret their home statutes which could have resulting impacts on regulatory processes and FEI's operations.

5.2.3 Indigenous Utility Inquiry Report Introduces New Risks for Incumbent Utilities

In April 2020, the BCUC released its final report as part of its Indigenous Utilities Regulation Inquiry (Inquiry Report), with a number of recommendations for the provincial government regarding the regulation of Indigenous controlled utilities. The Inquiry Report defined an Indigenous utility as a "public utility" for which, as the owner or operator, an Indigenous Nation has de facto or de jure control.[91] An Indigenous Utility could provide public utility services to persons within its service area free from BCUC regulation (i.e., self-regulating), without restricting the types of services offered.[92] An Indigenous Utility's self-regulating service area would vary between Indigenous Nations, but would be confined to reserve lands or lands covered by specific modern treaties, or self-governing agreements.[93]

The Inquiry Report further considered issues related to Indigenous Utilities providing service beyond reserve or treaty lands and the co-existence of Indigenous and incumbent utilities[94]. The report states that the franchise and exclusivity rights are a matter of public interest and considering the need for economic development of Indigenous communities, an existing franchise should not prevent an Indigenous utility from operating on reserve or treaty land. In certain cases where the Indigenous utility will likely materially impair the franchise of the incumbent utility, "a limited carve-

88 EAA, s. 11.
89 R.S.B.C. 1996, c. 187.
90 R.S.B.C. 1996, c. 238.
91 Inquiry Report, section 4.4.
92 An Indigenous utility would need to demonstrate it has its own arms length complaint and dispute resolution process to protect all ratepayers. Further, the BCUC would retain jurisdiction over Mandatory Reliability Standards (Inquiry Report, section 4.8).
93 Inquiry Report, sections 4.5, 4.6 and 4.7.
94 Inquiry Report, section 4.9

out of the incumbent utility's service area is required".[95] The BCUC also acknowledged that "the effective transfer of service area from the incumbent utility and the stranding of the incumbent utility's assets can be viewed as a seizure of the incumbent utility's assets unless compensation is provided or a compelling public interest reason exists"[96] and commented that a "reasonable compensation for the stranded assets could be the book value, which represents the portion of costs that are unrecovered, or the market value.[97]" The BCUC further proposed an incremental approach to the entry of Indigenous utilities operation within their asserted traditional territories and recommended that the UCA be amended to require the BCUC to consider UNDRIP and the economic development needs of a First Nation applying for a CPCN to operate an Indigenous utility on Traditional Territory.[98]

While it is still somewhat unclear how or when the provincial government may implement the BCUC's recommendations, implementation of these recommendations could potentially lead to reductions in rate base and earnings, higher rates caused by loss of demand from existing customers located in Indigenous utilities' service areas and further complicate the CPCN regulatory process.[99] Even though the recommendations have not been implemented, this risk has materialized with the Osoyoos Indian Band's notification to FBC of its discussions with a third party regarding the development of an Indigenous Utility for its business park, which is currently served by FBC.

5.3 ABORIGINAL RIGHTS AND TITLE LITIGATION AND RECENT COURT DECISIONS

Project proponents such as FEI may also be affected by judicial reviews of permits and authorizations for projects based on claims of inadequate consultation or other Indigenous rights litigation.

Risks exist to regulatory approvals and timing where Indigenous groups claim inadequate consultation or do not support a project or project approval. An example of such risks is shown in the Trans Mountain pipeline litigation where a number of challenges to regulatory decisions for that project have been put forward by Indigenous groups over several years. In this situation, most of the Indigenous groups along the project route supported or did not oppose the project, but a few of the Indigenous groups challenged the regulatory processes.[100]

[95] Inquiry Report, section 4.9.3, p. 65.
[96] Inquiry Report, p. 65.
[97] Inquiry Report, p. 66.
[98] Inquiry Report, section 4.9.4
[99] BC's DRIPA draft action plan included as an action the engagement of First Nations to identify and support clean energy opportunities related to the Inquiry Report (action 4.24), which suggests that BC may take some action with respect to the BCUC's recommendations prior to 2026.
[100] *Tsleil-Waututh Nation v. Canada (Attorney General)*, 2018 FCA 153*; Coldwater First Nation v. Canada (Attorney General)*, 2020 FCA 34.

In June 2021, the BC Supreme Court found cumulative impacts from industrial development in the North Montney region of BC infringed Blueberry River First Nations' (Blueberry) treaty rights.[101] The court found that Treaty 8 rights included a promise that a way of life based upon hunting, fishing and trapping would not be forcibly interfered with and that the basic elements needed for this way of life to continue would not be destroyed. As a result of the decision, BC was ordered to establish mechanisms to assess and manage cumulative impacts of industrial development. BC and Blueberry are in the process of negotiating such mechanisms.

In October 2021, BC and Blueberry reached an initial agreement addressing the majority of permitted but not yet started projects in the area (though 20 currently approved authorizations will not proceed without further negotiations) and providing $65 million to Blueberry. However, the cumulative impacts framework is still being negotiated. In the interim, the review of applications for decisions are being prioritized based on emergency, environmental protection and public safety (though review of most applications has essentially halted).[102] The provincial government has also announced that it would engage with other Treaty 8 First Nations regarding the development of any such mechanism.

As a result of the decision and the ongoing negotiations, significant delays for authorization applications in the Treaty 8 region are expected until the new mechanism to assess and manage cumulative effects is developed as well as after to deal with the inevitable backlog of applications. Further, at this point, it is currently unknown what such a mechanism may look like and what risks it may add to FEI's operations. Risks are expected for FEI's operations and related applications within Treaty 8 and potentially elsewhere in BC if BC considers implementing such a mechanism in other areas of BC. The decision and the current negotiations have also created considerable uncertainty in BC's investment climate.

In *Thomas and Saik'uz First Nation v. Rio Tinto Alcan Inc.*, the BC Supreme Court acknowledged that Indigenous groups have the ability to pursue private law claims such as nuisance or trespass against third parties, including project proponents, based on impacts to Indigenous rights and title.[103] However, where a third party's conduct has been statutorily authorized, this can be used as a full defence against the claims. This case increases risk for project proponents because it expands the circumstances in which Indigenous groups may bring claims against third parties and may result in an increase in claims being brought against project proponents with respect to impacts to Indigenous rights.

---

[101] *Yahey v. British Columbia*, 2021 BCSC 1287.
[102] BC and Blueberry River First Nations working together (INDB 2021-28) | BC Oil and Gas Commission (bcogc.ca).
[103] 2022 BCSC 15.

There are also other Aboriginal rights claims currently before the courts with the potential to impact project proponents.[104] The relief sought in these claims varies, including damages and injunctions against existing infrastructure.[105]

Litigation risk associated with potential projects is also recently demonstrated in the claim brought by the West Moberly First Nation, alleging that the BC Hydro Site C project infringes its treaty rights. West Moberly are seeking a permanent injunction to prohibit the construction of the project, and also sought an interlocutory injunction application as part of that proceeding.[106] Prior to the claim, the West Moberly First Nations (with the Prophet River First Nation) sought judicial reviews of the environmental assessments and other permits for the project.[107]

5.4 *SOCIAL LICENCE CHALLENGES AND WORK DISRUPTIONS ARE OCCURRING*

There has also been an increase over the past few years in blockades and demonstrations on the ground where members of Indigenous groups or other individuals do not support a project. Such blockades and demonstrations can prevent access to project construction sites, assets and operations, delay construction of projects and may require a proponent to seek an injunction to prohibit interference with a project, assets or operations.

Challenges can also exist for the Crown and project proponents to determine the proper body which represents the Indigenous rights-holders for the purposes of consultation or negotiation of a project agreement. Further, disagreement can occur between governing bodies of an Indigenous group, or between an Indigenous group's governing body and individual members regarding whether to support or oppose a project, as can be seen in the Wet'suwet'en example discussed above and below. There are also circumstances where the majority of an Indigenous group support a project, but there is a smaller, but dedicated faction within a community that opposes the project. Those factions can often cause significant issues for projects and increase risk.

The Coastal GasLink natural gas pipeline project is a recent example of a linear pipeline project in BC, where the proponent had support from all of the Indigenous bands along the pipeline route but did not have support from a faction of the hereditary leadership of one of the Indigenous groups. The situation resulted in blockades on the ground, necessitating Coastal GasLink to seek an injunction to prevent impediments to its construction of the project.[108] The protests of the Coastal GasLink project expanded, with blockades being erected multiple times and with major

---

104 For example, *Anderson v. Alberta (Attorney* General), 2020 ABCA 238.

105 *Newfoundland and Labrador (Attorney General) v. Uashaunnuat (Innu of Uashat and of Mani Utenam)*, 2020 SCC 4.

106 *West Moberly First Nations v. British Columbia*, 2018 BCSC 1835.

107 *Prophet River First Nation v. British Columbia (Environment)*, 2015 BCSC 1682 and 2017 BCCA 58; *Prophet River First Nation v. Canada (Attorney General)*, 2015 FC 1030 and 2017 FCA 15; *Prophet River First Nation v. British Columbia (Minister of Forests, Lands and Natural Resource Operations)*, 2016 BCSC 2007.

108 *Coastal GasLink Pipeline Ltd. v. Huson*, 2019 BCSC 2264.

infrastructure across the country being blockaded and several other injunctions being granted to other parties whose assets were blockaded.[109]

Due to both the nature of FEI's business including linear projects and the large number of Indigenous groups who have overlapping territories across FEI's service area, FEI faces risk of a similar nature to Coastal GasLink. The reality of trying to achieve support and consent from dozens of Indigenous groups over a wide geographic area is uncertain and creates significant risk if there is just one Indigenous group, or factions within one Indigenous group, that opposes a project or existing infrastructure.

In addition to litigation risks and risks of demonstrations, lack of support or consent from Indigenous groups can also create delays in regulatory processes and project timelines.

As a result of the Declaration, DRIPA, the UNDRIP Act, the new legislation and recent case law, Indigenous groups have increased expectations with respect to consultation and accommodation, their involvement in decision-making and obligations around seeking and obtaining consent which have added costs and extended timelines to permitting processes and added risks of disruptions to projects through legal challenges or blockades and demonstrations.

[109] For example, Canadian Pacific Railway Limited v. Doe, 2020 BCSC 388.

6. ENERGY PRICE RISK

Energy prices impact a utility's business risk because price is among the factors that can influence consumer energy choices. Electricity remains the primary alternative available in British Columbia for space and water heating.[110] There are a number of factors that impact the price competitiveness of natural gas in BC relative to electricity.[111] They include:

- Natural gas commodity price;
- Natural gas commodity price volatility; and
- Price competitiveness, including the impact of increasing carbon tax and an increased share of higher priced Renewable Gas in FEI's gas supply portfolio as well as a consideration of the relative installation costs of gas appliances compared to electric appliances.

While commodity price remains a driver of business risk, recent experience suggests that other non-price considerations such as GHG emissions, new technologies, type of housing mix and the size of new dwellings, customer perceptions and government policy (such as local governments' support for non-fossil fuel alternatives through updates to building codes and bylaws, which is discussed in the previous section), are taking on greater importance in the decisions of energy consumers. These other considerations are addressed in Sections 4 and 7.

FEI's assessment is that the overall energy price risk is higher than 2015 levels that were reviewed in the 2016 Proceeding. Specifically:

- Section 6.1 explains that natural gas prices are higher, having been affected by flat natural gas production, and the long term forecast is for prices to remain higher than they were in 2015.
- Section 6.2 discusses natural gas prices being more volatile due to the impact of increasing demand in the Pacific Northwest and increasing constraints on regional infrastructure.
- Section 6.3 details how FEI's price competitiveness has eroded significantly on any basis of comparison – using energy cost alone, energy cost including installation cost, when adding in carbon tax, and when incorporating increasing volumes of more costly Renewable Gas.

[110] In this document, the references to electricity as an energy source in British Columbia mainly relate to BC Hydro, which delivers nearly 95 percent of electricity within the province.

[111] This was recognized by the BCUC in its 2009 Cost of Capital Decision, p. 36, where the BCUC stated: "…natural gas' competitive edge over electricity is dependent on too many significant variables, such as the level of the carbon tax, the volatility of natural gas prices and the impact of government policy on BC Hydro's rates, to be considered permanent".

6.1 NATURAL GAS COMMODITY PRICE

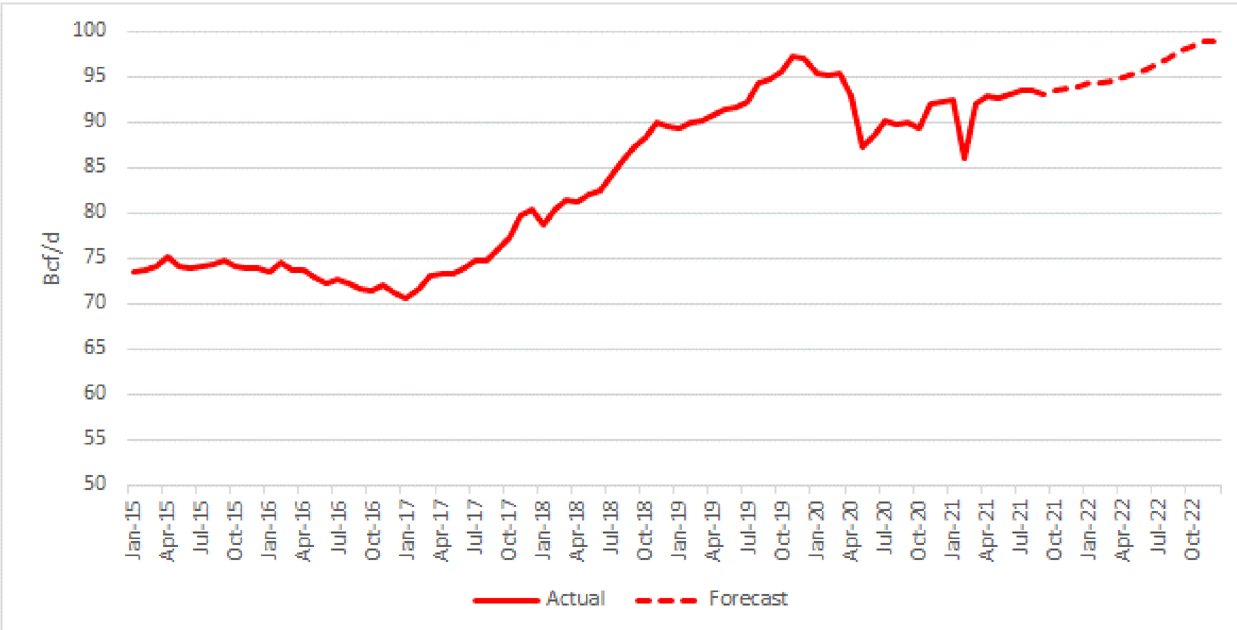
This section addresses the commodity price of natural gas and how it affects FEI's competitive position. While natural gas commodity prices are set by the market, electricity prices are heavily influenced by BC Hydro's low embedded costs, making it more difficult for FEI to compete against electricity than gas utilities in many other provinces. Natural gas competitiveness in BC and in other provinces in Canada is further challenged by the implementation of the carbon tax as well as other non-price factors.

6.1.1 Flat Natural Gas Production Has Put Upward Pressure on Regional Prices

In general, commodity rates in the natural gas utility sector reflect the utility's cost of purchasing the gas on behalf of its customers, without mark-up. Natural gas prices are set in an open and competitive market and are influenced by many variables throughout North America, as well as each utility's operating region. Commodity rates will therefore fluctuate in response to changes in supply and demand conditions for natural gas.

As in 2015, the current North American natural gas marketplace continues to be heavily influenced by the abundance of shale gas supply. Continued advances in drilling technology associated with shale gas and the upsurge in associated natural gas supply from increased oil production in the past few years had resulted in an oversupplied natural gas market. However, in March of 2020, production fell (as can be seen in Figure A6-1 below) due to low crude oil prices and producers using fiscal discipline and constraining capital costs on drilling and production output, which reduced associated gas output. This resulted in near term prices rising due to demand increasing while supply has remained stagnant. Supply is forecasted to increase and alleviate some of the pressure on prices and help to meet the increasing demand from LNG exports, exports to Mexico, electricity generation and back-up for intermittent renewable energy. U.S. dry gas production has reached 93 Bcf/day in September 2021 having increased significantly since 2015 when production was at 73.4 Bcf/day in January 2015. Figure A6-1 below shows the actual U.S. dry gas production from January 2015 to September 2021 and the forecasted production from October 2021 to December 2022.

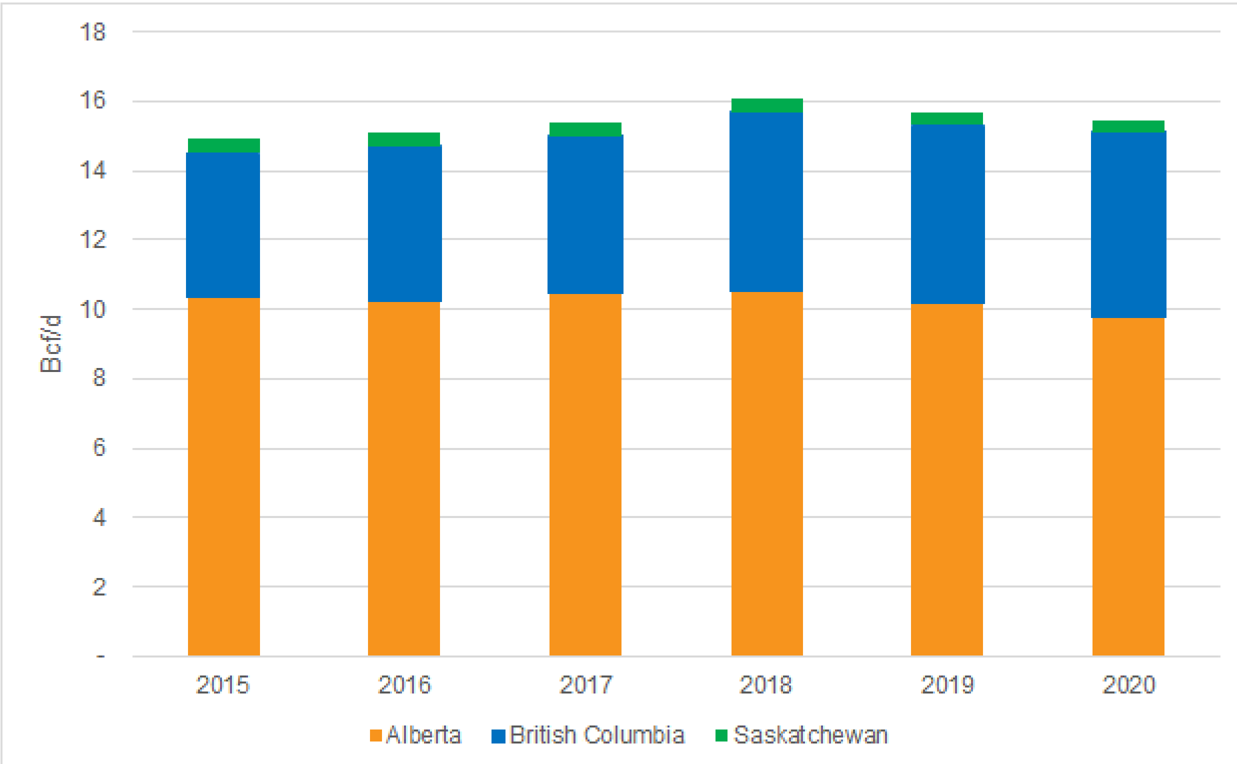
Figure A6-1: U.S. Dry Gas Production (Actual and Forecast)[112]



This supply growth has also occurred in BC as natural gas production has increased over one Bcf/day since 2015. However, overall the production in the Western Canadian Sedimentary Basin (WCSB) has been flat as declines in Alberta and Saskatchewan production levels have offset the increases in BC production. Figure A6-2 below shows the annual WCSB production totals in Alberta, BC and Saskatchewan.

[112] EIA - Short-Term Energy Outlook – October 2021.

Figure A6-2: WCSB Production Growth[113]



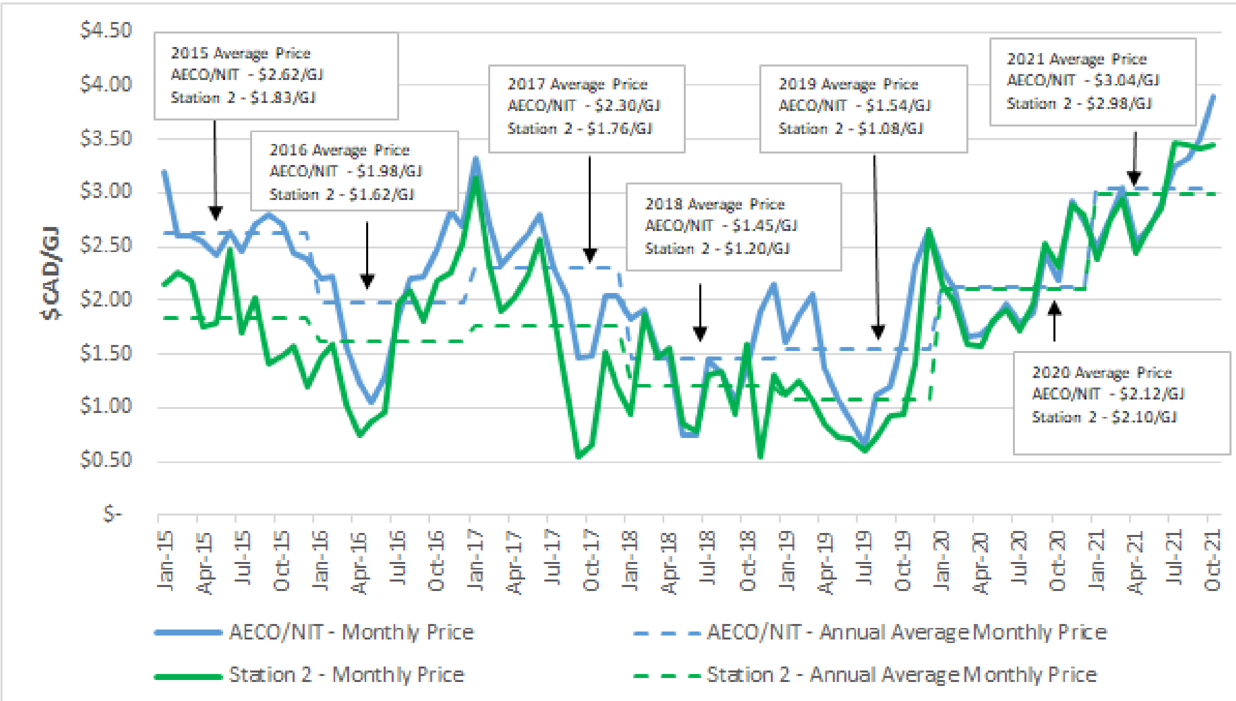
The flat production levels in the WCSB have contributed to regional natural gas prices increasing. Figure A6-3 below illustrates the AECO/NIT[114] and Station 2[115] monthly prices from January 2015 to October 2021. While AECO/NIT and Station 2 prices experienced some decline since 2015, Station 2 prices have risen and the differential between AECO/NIT and Station 2 has tightened.

[113] Source: ©2021 IHS Markit. All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.

[114] AECO/NIT (NOVA Inventory Transfer) is one of the largest natural gas trading hubs in North America, located in Alberta. AECO/NIT prices can be used as a high-level proxy for FEI's commodity supply portfolio costs.

[115] Station 2 is the main natural gas trading hub in northern BC. Natural gas produced in northern BC is traded here and then moved to markets further south or east into Alberta and US markets.

Figure A6-3: AECO/NIT and Station 2 Natural Gas Monthly and Annual Average Prices



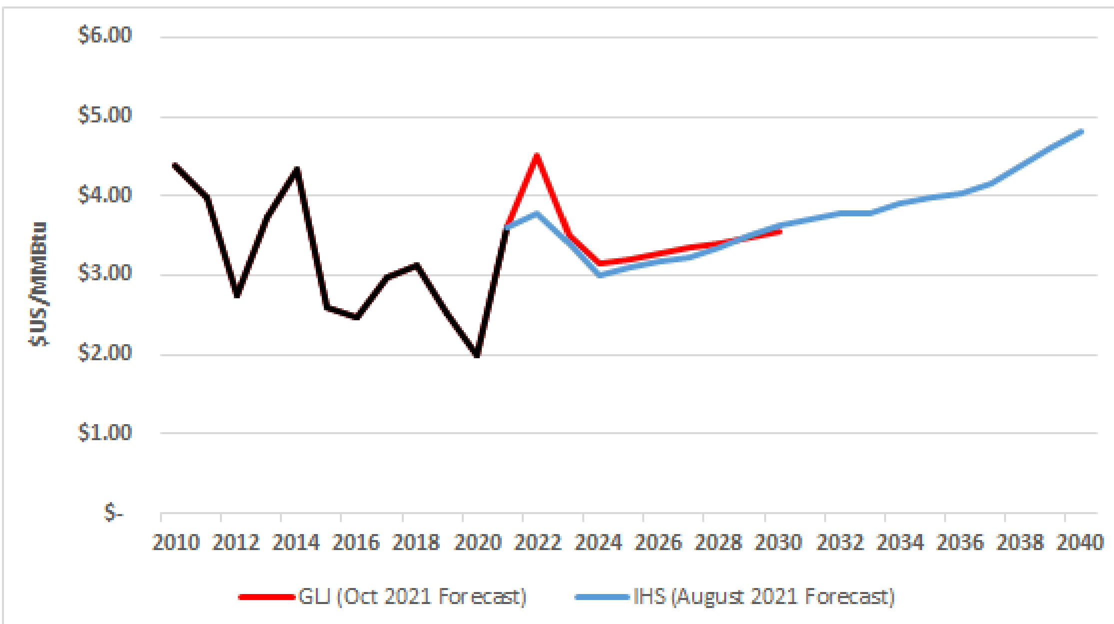
6.1.2 Natural Gas Prices Are Higher Compared to 2015

FEI purchases a mix of AECO/NIT price based monthly supply in Alberta and at Station 2, and daily priced supply at both AECO/NIT and Station 2 to meet its customer requirements. When looking at both AECO/NIT and Station 2 average prices, actual 2021 market prices at AECO/NIT and Station 2 have increased 16 percent and 63 percent respectively from where they were in 2015.

Relative to the cost of other energy sources, the low prices for natural gas in recent years have provided incentives and opportunities for the greater use of natural gas across North America and have been a key driver for increasing demand. The majority of demand growth has been from LNG exports, exports to Mexico, as well as industrial demand, specifically from the petrochemical sectors. Demand has also increased due to new electricity load powered by natural gas and greater switching from retiring coal-fired power plants to natural gas and combined cycle power plants. Regionally, the addition of LNG Canada coming on line in 2026, and the possibility of Woodfibre LNG to follow, will likely continue to put pressure on prices, especially if supply production does not keep up with forecasts.

In terms of supply, as stated above, producers are continuing to improve their balance sheets and becoming financially healthier. This is expected to contribute to production growth as forecasted. However, crude oil prices can play a major role in reducing associated gas output, which is produced as a by-product of the production of crude oil and is more responsive to crude oil prices rather than natural gas prices, as happened in 2020. The drop in oil prices in 2020 was caused by the excess global supply of crude oil and lower demand induced by the COVID-19 pandemic. As occurred in 2020, if oil and associated gas production is reduced, this could cut overall gas supply and lead to higher natural gas prices as the average cost to produce gas increases without contribution from liquids-rich associated gas; this has been a factor in increased prices seen in 2021. Figure A6-4 below compares long-term price forecasts from different information sources for Henry Hub[116] natural gas that would reflect the expectations of the impact of long-term natural gas supply and demand fundamentals. The long term forecasts indicate that by 2030, gas prices could be above $3.50 US/MMBtu and continue to increase above $4.00 US/MMBtu out to 2040. As described in section 4.2.2.1, the natural gas commodity price may be further impacted by the provincial government's Roadmap and restrictions placed on the oil and gas sector.

Figure A6-4: Long-Term Henry Hub Natural Gas Price Forecasts (nominal dollars)[117]



Given that current and 2021 forecasted market prices for natural gas are higher than the actual 2015 prices, FEI assesses the natural gas commodity price risk to be higher compared to 2015.

[116] Henry Hub is the benchmark gas trading hub for North America and is located in Louisiana.

[117] Source: ©2021 IHS Markit. All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.

6.2 NATURAL GAS COMMODITY PRICE VOLATILITY

The natural gas market continues to be volatile and is more volatile than it was in 2015. With the anticipation of increased demand in the region and infractructure becoming more constrained, regional price disconnections are expected to continue.

6.2.1 Volatility is Greater Compared to 2015

Natural gas prices are more volatile than electricity prices in BC principally due to the fact that natural gas is market-based, while electricity supply is primarily cost-based. Price volatility is an impediment to attracting and retaining natural gas customers because it can have a negative impact on natural gas rates and can negatively influence consumers' view of using natural gas as a fuel[118].

With the abundance of shale gas supply in North America, the natural gas market price environment continues to remain relatively low compared to the pre-shale gas era, but with the continued potential for price volatility, which has occurred recently. For example, some regions may have limited pipeline or storage infrastructure to meet demand during peak times, which can lead to market price spikes and higher price volatility. BC is one of these regions where infrastructure is limited during high demand periods, and is becoming increasingly constrained due to market dynamics in the region.

Natural gas price volatility has increased. From 2015 to 2018, forward curve prices decreased in each year, with AECO/NIT forward prices dropping from $3.00/GJ down to $2.00/GJ as supply exceeded demand across North America. In 2019 and 2020, lower natural gas production in the WCSB, due to producers' continuing fiscal discipline and constraining capital costs on drilling and production output, decreased supply causing forward prices to increase. Currently, 2021 forward prices have become more volatile and increased further, averaging over $3.50/GJ for the next two years, as demand continues to outpace supply.

Compared to 2015, the 95 percent confidence range for recent forward market gas prices has widened, reflecting the potential price volatility and continuing uncertainty as to where market prices could ultimately settle in the future. This is illustrated in comparing Figures A6-5, which was included in the 2016 Proceeding and Figure A6-6 that has been updated with a more recent forward curve.

[118] FortisBC Customer Volatility Tolerance & Preferences study prepared by Sentis Research, June 2017.

Figure A6-5: AECO/NIT June 30, 2015 Forward Price Curve and 95% Confidence Interval Bands

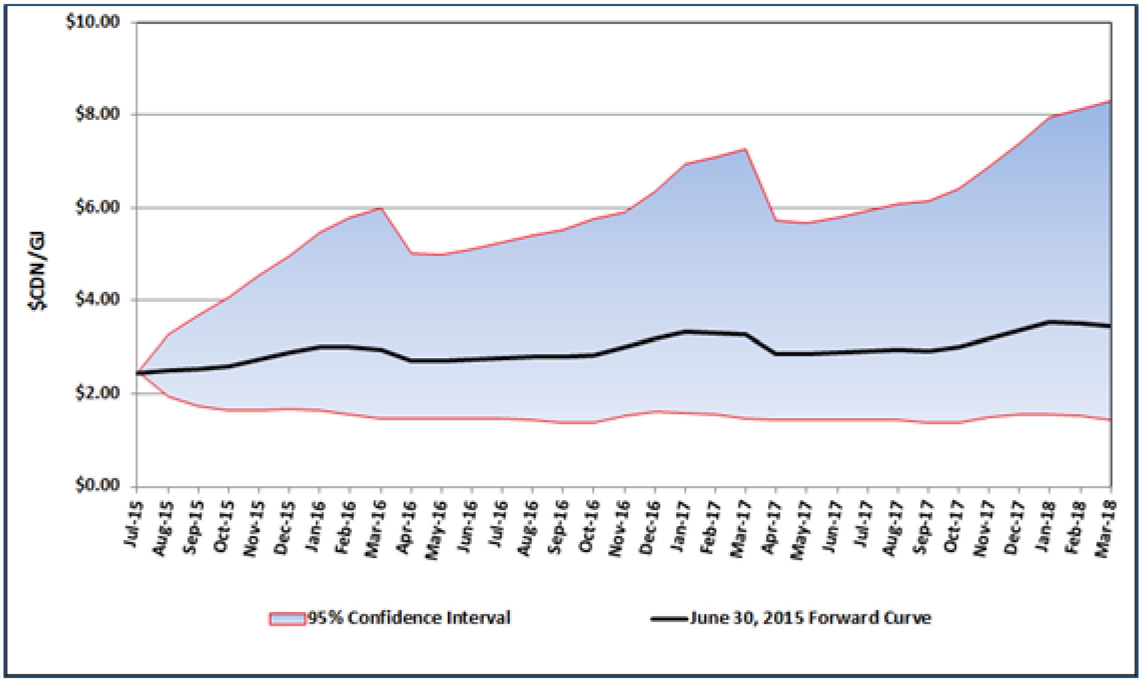
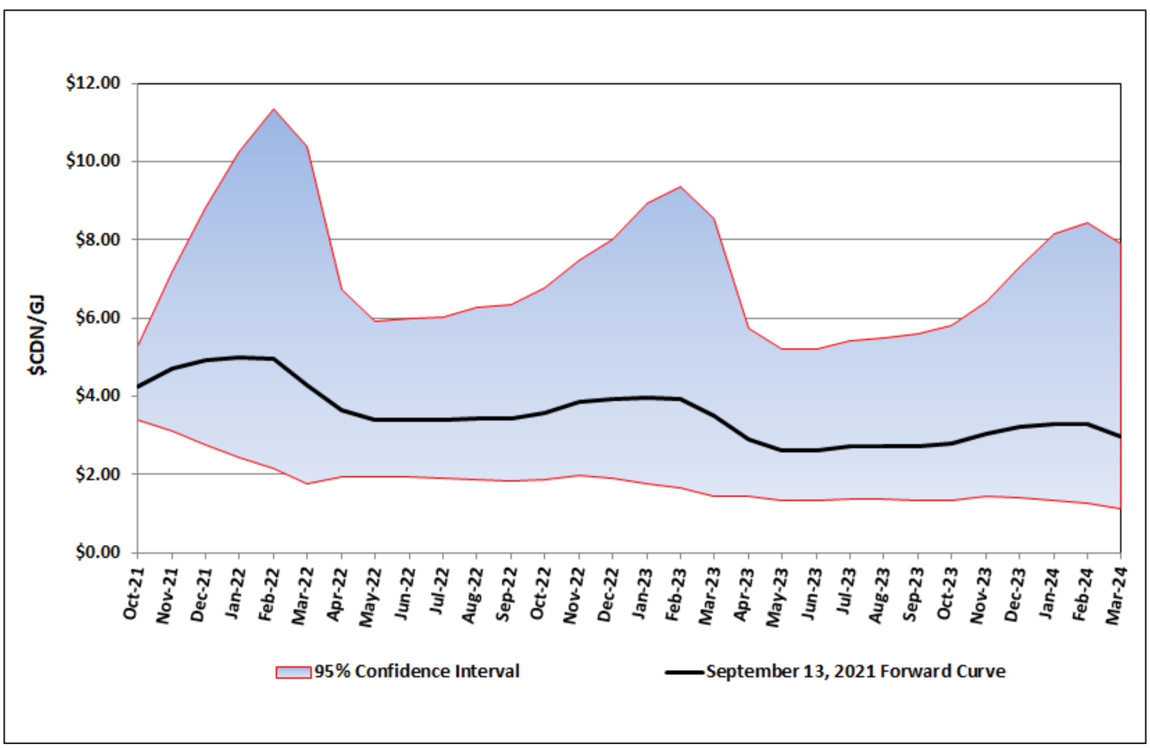
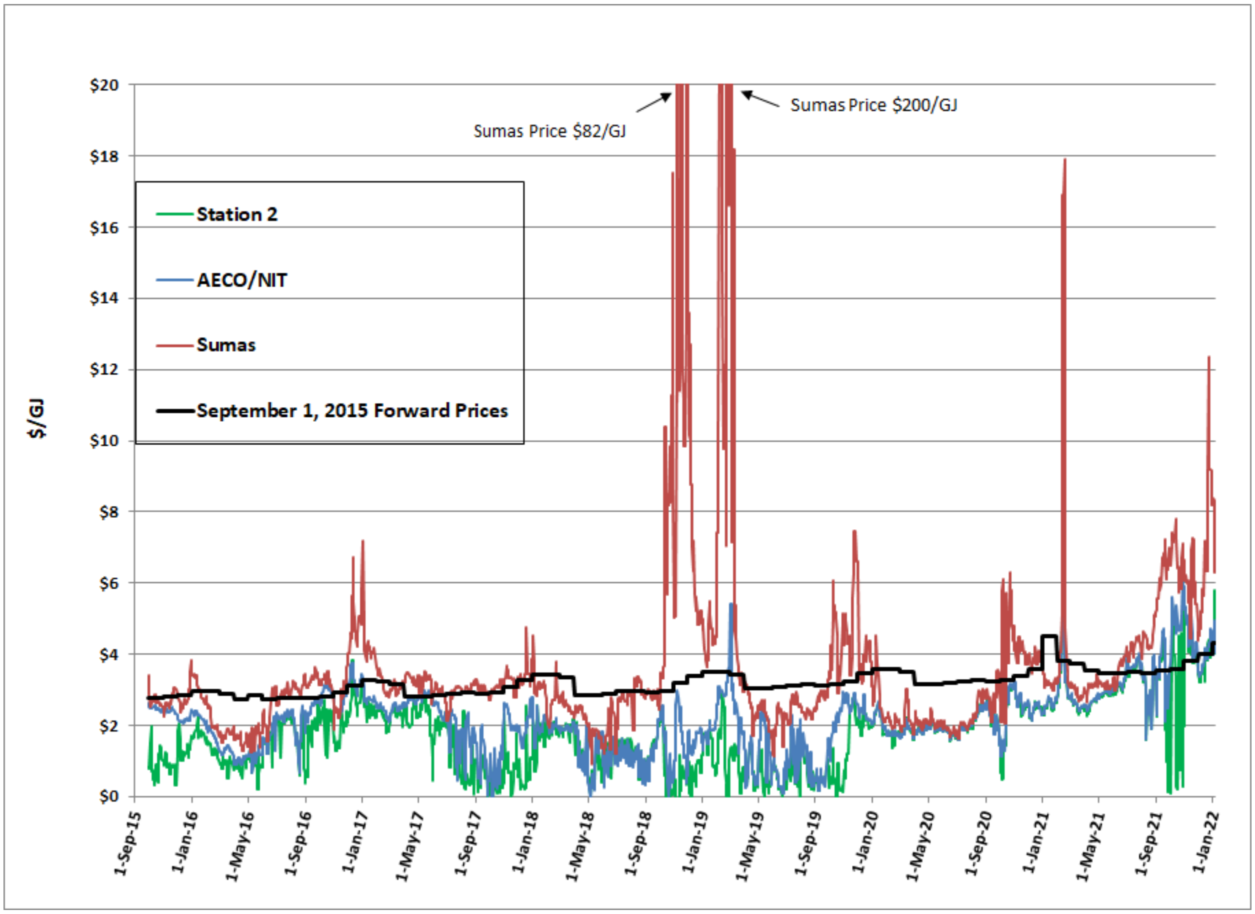


Figure A6-6: AECO/NIT September 13, 2021 Forward Price Curve and 95% Confidence Interval Bands



Daily gas prices have been even more volatile than monthly and forward market prices. The following Figure A6-7 shows the actual AECO/NIT, Station 2 and Sumas[119] daily prices since 2015 compared to the September 1, 2015 forward curve[120]. The volatility in monthly prices is typically less significant because daily prices typically react to immediate actual supply and demand events, while monthly prices are set based on the market's expectations of supply and demand for the upcoming month.

Figure A6-7: Actual Regional Daily Prices



As illustrated, regional daily gas prices have fluctuated from lows of negative prices in October 2018 to highs of over $200/GJ in March 2019 and continued volatility as shown in 2020 and 2021.

The largest price spike occurred in winter 2018/19, after the Enbridge pipeline rupture, where the Sumas price was disconnected more than AECO/NIT and Station 2 prices (which are most relevant to FEI, given that is where the bulk of FEI's gas commodity is purchased). Restricted gas

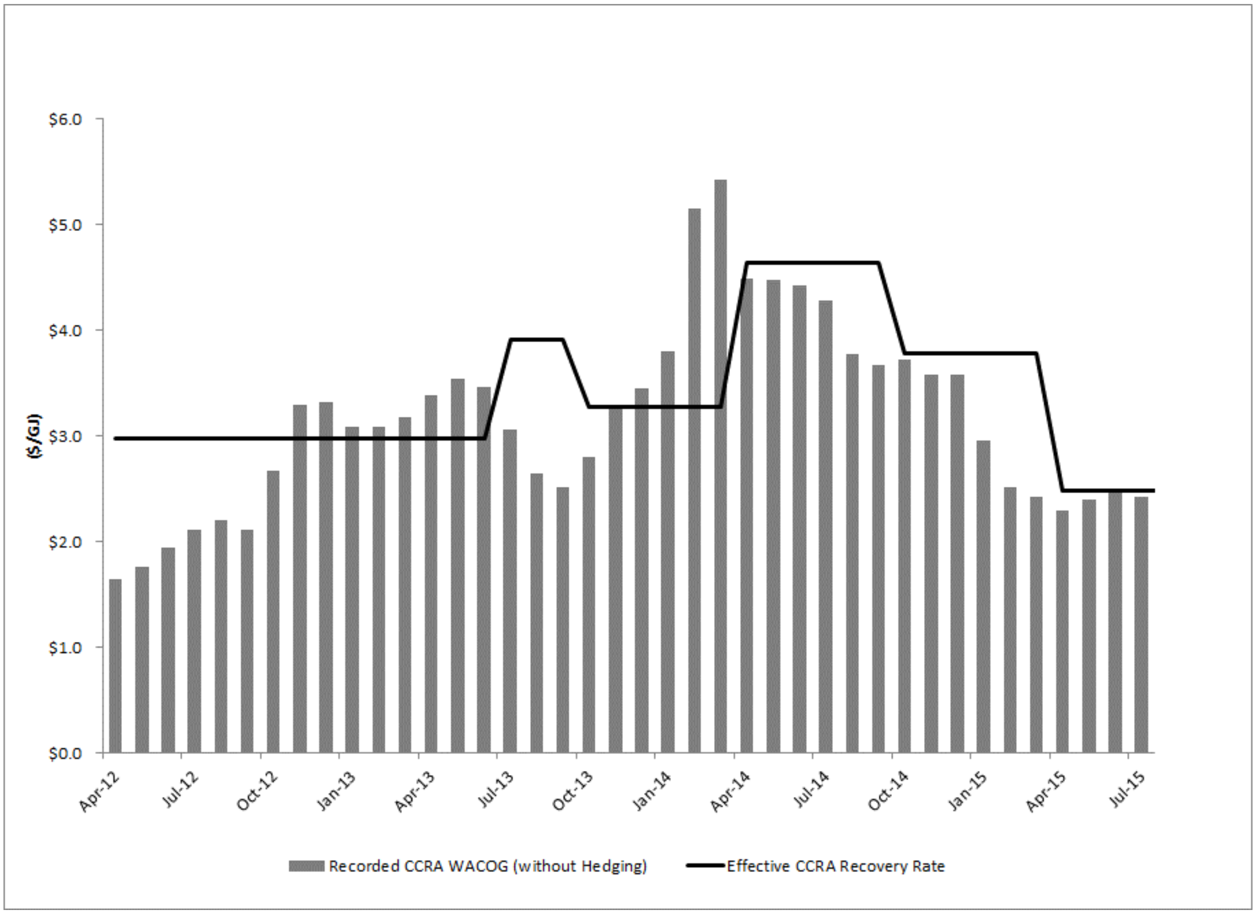
[119] Sumas is the trading hub located on the BC-Washington border at Huntingdon. It is the main trading hub for BC gas supply moving south to US markets.

[120] AECO/NIT Forward Price Curve as of September 1, 2015.

flows due to the Enbridge pipeline rupture and cold weather caused prices to spike above $80/GJ in November 2018. The combination of continuing T-South capacity restrictions, cold winter weather and storage operational issues in the Pacific Northwest (PNW) in February 2019 caused Sumas daily prices to spike to record levels of $200/GJ. Sumas market prices were at higher than normal levels for most of the 2018/19 winter period. More recently, pricing volatility occurred in February and December 2021, as prices spiked close to $18 per GJ and $12 per GJ, respectively. The price spike in February was due to cold weather in the PNW at the same time as frigid temperatures for much of the US midcontinent, while record breaking extreme cold in the PNW caused Sumas prices to spike in December. Sumas volatility is important to note because FEI's Transport Model customers located in the Lower Mainland may purchase their commodity off the Sumas index (i.e., monthly or daily).

Only some of the market price volatility is reflected in FEI's commodity portfolio weighted average cost of gas (WACOG) due to the use of deferral accounts and rate-setting mechanisms and since most of FEI's gas commodity is purchased at AECO/NIT and Station 2. The WACOG represents the actual cost of gas purchased and ultimately recovered from customers through commodity rates. Figure A6-8 illustrates the Commodity Cost Reconciliation Account (CCRA) WACOG and FEI's actual commodity rates from 2012 to 2015, in the lead up to the 2016 Proceeding.

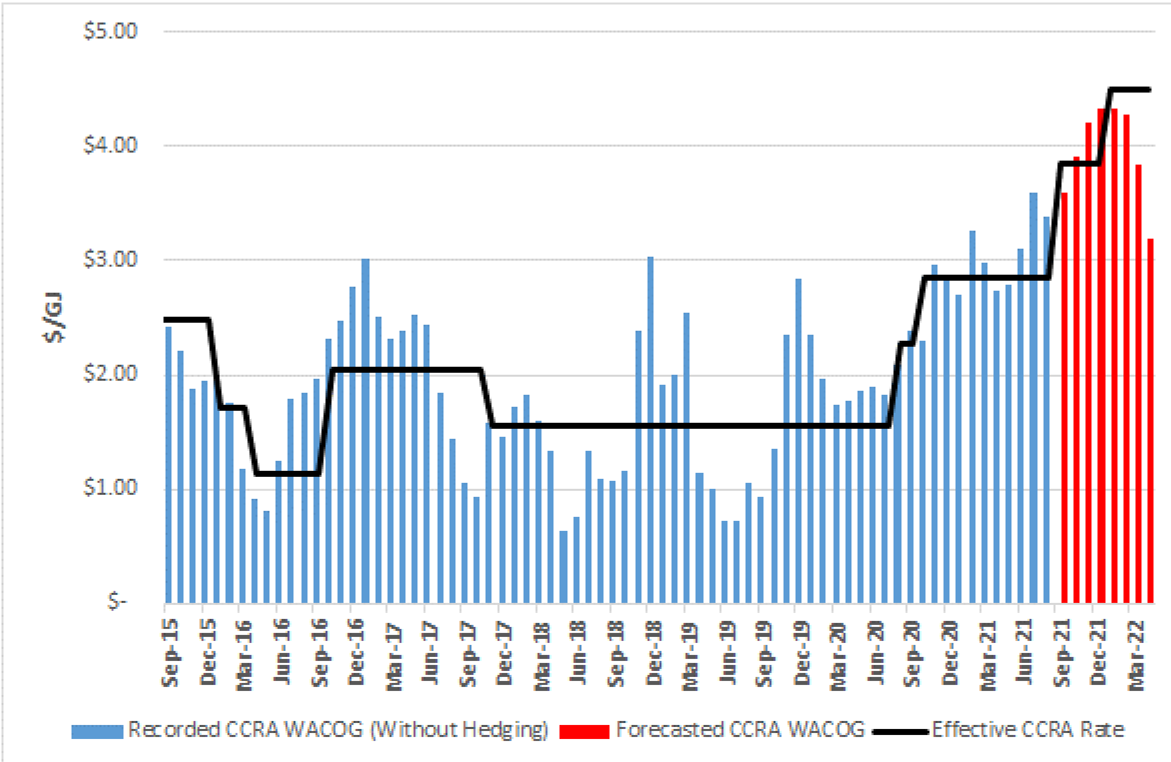
Figure A6-8: 2012 – 2015 WACOG (excluding hedging) vs Commodity Rate



FEI's commodity rate fluctuated during that time period, moving from near $3/GJ in 2012 up to almost $5/GJ in 2014 and then back down again to near $2.50/GJ in 2015.

The following Figure A6-9 is updated to show FEI's WACOG and actual commodity rates over the past six years.

Figure A6-9: 2015 – 2022 WACOG (excluding hedging) vs Commodity Rate



As Figure A6-9 above illustrates, similar to the regional gas prices at AECO/NIT and Station 2, FEI's WACOG and commodity rate have fluctuated throughout the past six years, although the commodity rate did remain more stable and was unchanged from January 2018 to July 2020. Recently, volatility has increased and FEI's commodity rate has increased to $4.50/GJ in January 2022, up from $2.22/GJ in August 2020, as increased demand and lower supply continue to cause volatility at all the regional markets as explained in Section 6.1 above.

6.2.2 Regional Market Price Volatility Is Expected to Continue

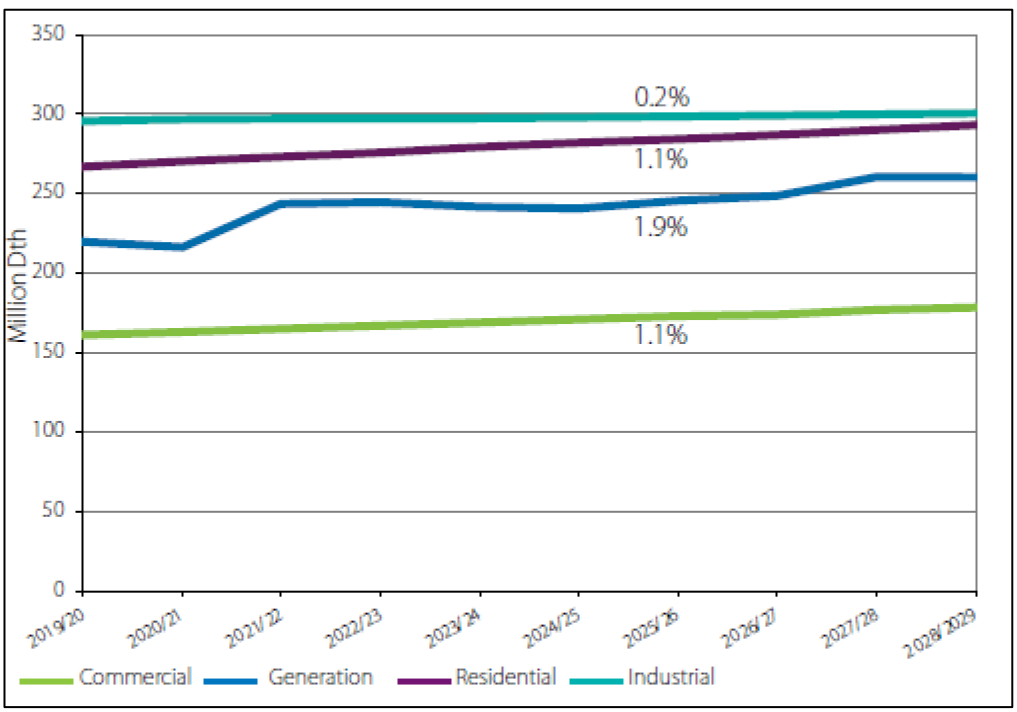
This regional market price volatility is expected to continue in the future. Regional infrastructure additions can help mitigate some of the regional price disconnection risk; however, these additions require a long time to plan, to secure shipper commitments, to receive regulatory approval, and to construct. The Southern Crossing Pipeline, Westcoast T-South, Mist, Jackson Prairie storage facilities expansions are examples of regional infrastructure projects that were approved and subsequently constructed to meet growing regional demand that helped to reduce some of the regional constraints. However, further infrastructure is needed to meet the pace of future demand growth, provide resiliency and help to complement the clean energy transition in the PNW region.

Future demand growth has been driven by relatively low natural gas prices. Particular areas of anticipated growth are for electricity generation and to supply the LNG export market. Each of these areas have had growth since 2015 and are discussed briefly below.

In recent years, natural gas usage for power generation has increased in the PNW, due to the retirement of coal plants. As power generation from coal is replaced with renewable projects in the region, it is uncertain what the future usage will be, as renewables are not sufficiently available at this time, and will be intermittent, depending on weather conditions. Therefore, natural gas demand and power market in the PNW will continue to become more interconnected, consequently increasing price volatility.

The 2020 Natural Gas Outlook by Northwest Gas Association (NWGA) reviews the role that natural gas will need to play in maintaining system reliability and affordability as the U.S. PNW is required by public policy to adopt the use of more renewable energy.[121] Figure A6-10 shows the forecast increase in natural gas demand in 2020/21 and also in 2026/27, which corresponds to the major coal retirements in the region.

Figure A6-10: Regional Natural Gas Demand by Sector [122]



The first LNG export project to receive approval to proceed in western Canada was LNG Canada in October 2018. LNG Canada is located in Kitimat and is expected to come online in 2026. Phase One will have two "trains" or separate LNG cooling processes. Each train is being

[121] NWGA (2020). "2020 NWGA Gas Outlook."
[122] Northwest Gas Association (2020). "2020 NWGA Gas Outlook."

designed to handle 6.5 million tonnes per year of LNG exports to Asia for a total of 13 million tonnes annually (around 1.8 Bcf/day of gas) in the first phase. Another project that is expected to proceed is Woodfibre LNG. It is forecasted to export an additional 0.5 Bcf/day beginning in 2027.

Given these developments, it is apparent that the natural gas and power markets in the region are becoming increasingly connected. This interconnection may cause increasing volatility at the market hubs in the West, and/or elevated natural gas prices during the winter season, depending on certain weather and market conditions beyond the I-5 corridor and into the West in general. With the fully contracted use of regional infrastructure, and potential for increasing demand, there is greater risk of price spikes lasting for longer periods of time. This future outlook increases FEI's price risk.

With regional market price volatility continuing, regional infrastructure becoming more constrained in the future unless planned infrastructure projects can proceed, FEI assesses the risk associated with market price volatility to be higher than at the time of the 2016 Proceeding.

6.3 *PRICE COMPETITIVENESS: GAS VERSUS ELECTRICITY*

A potential natural gas customer often compares the cost of gas space heating and water heating equipment with the alternative electric options before making a purchase decision. As such, price competitiveness of natural gas versus electricity is an important risk factor that needs to be analyzed. Compared to 2015, FEI's price competitiveness risk has increased and will likely continue to increase in the next number of years.

In the following sections, the price competitiveness of natural gas is compared with electricity from both the energy cost and total cost (energy cost plus capital and maintenance costs) perspectives. Further, the role of carbon pricing on the future of natural gas price competitiveness is discussed in more detail, as well as the impact of increasing supplies of Renewable Gas on price competitiveness.

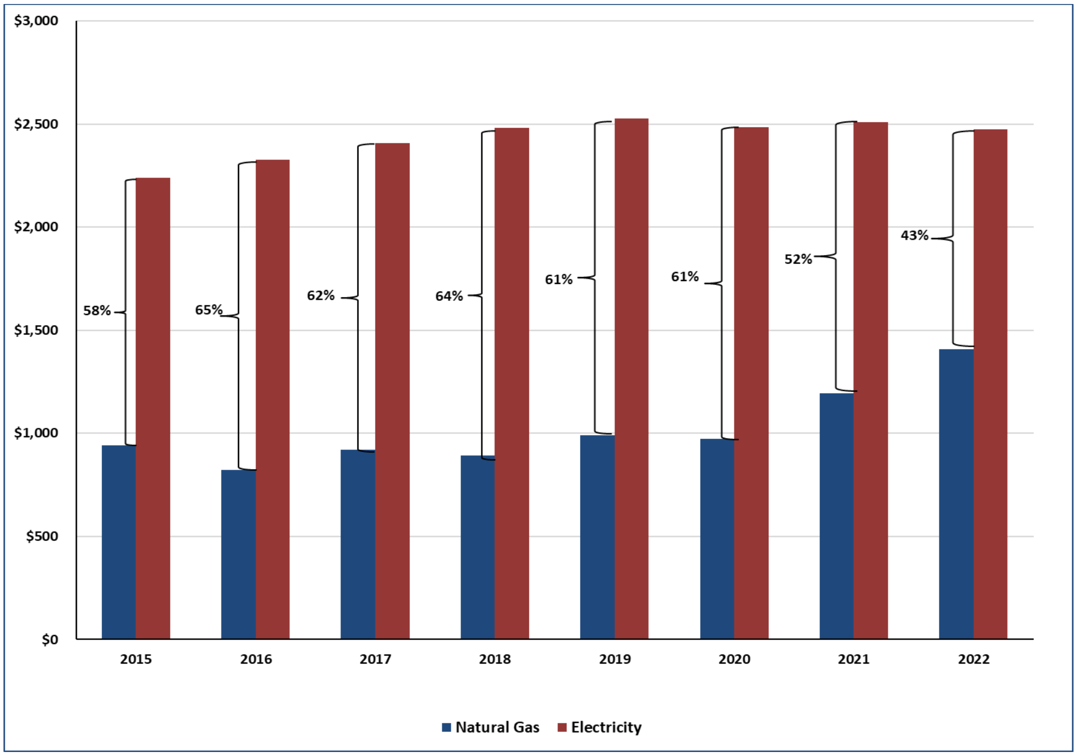
6.3.1 Price Competitiveness Based on Energy Cost Has Decreased since 2015 and this Trend Is Expected to Continue

Below, FEI compares its energy rates (excluding installation costs) against BC's electricity rates and against rates in other jurisdictions in Canada.

Comparison to BC's Electricity Rates

A review of the trend in the energy cost differential between natural gas and electricity indicates that, compared to 2015, natural gas' cost advantage has declined and therefore FEI's price competitiveness risk has increased. Figure A6-11 below shows the trend in annual bill amounts based on FEI's burner tip rates versus BC Hydro's electric equivalent rates, with the favourable energy cost advantage held by gas decreasing from 58 and 65 percent (2015 and 2016) to 43 percent (2022).

Figure A6-11: Residential Annual Bill Amount Trend in BC



Assumptions:

- Estimated residential bills are based on prevailing rates on April 1 of each specified year. BC Hydro bill estimates exclude the basic charge since a household already pays the basic electric charge for non-heating use.
- The average efficiency of gas equipment is assumed to be 92% relative to 100% for electricity to determine equivalent electric rates.
- Estimated bills are calculated based on annual use rate of 90 GJs.
- FEI bills are inclusive of the BC Carbon Tax and exclude other applicable taxes.

As shown above, the favourable energy cost differential for natural gas compared to electricity peaked in 2016 at about 65 percent; meaning that, all else equal, a natural gas customer's annual bill would have been 65 percent lower than its electric equivalent[123]. However, since 2016, the natural gas energy cost advantage is on a downward trend, with the 2022 differential declining to 43 percent. The sharp decrease in energy cost differential between natural gas and electricity in the 2021-2022 period can be attributed to higher natural gas commodity cost as well as delivery rate and carbon tax increases. All else equal, and considering the projected increases to provincial carbon tax, as well as BC Hydro's proposed rate changes in its recently-filed 2023-

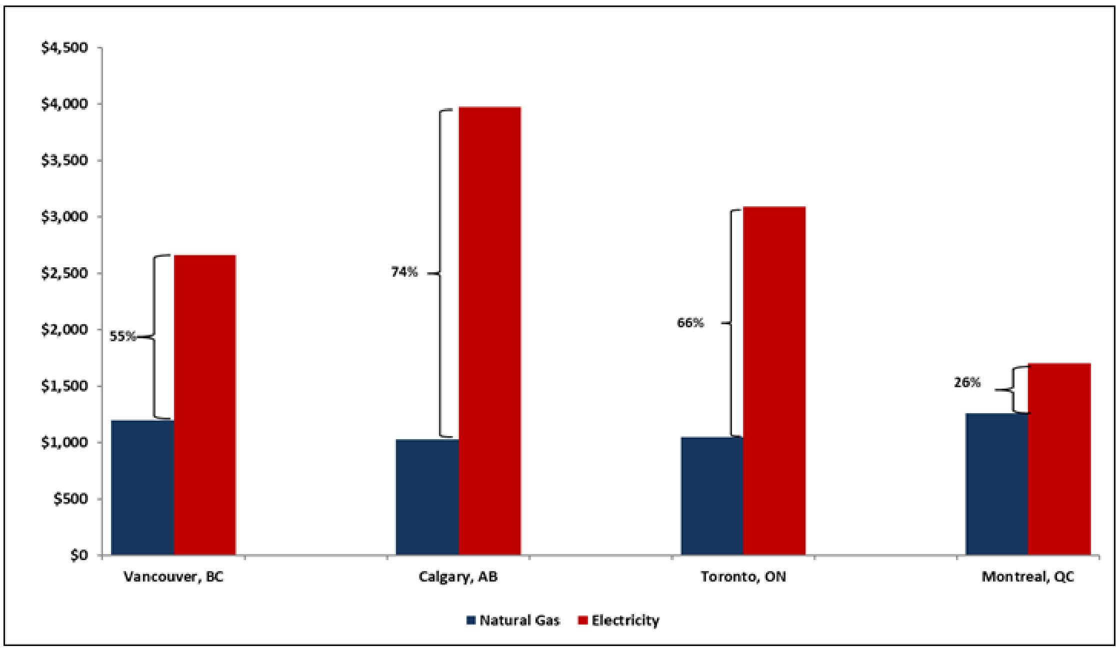
[123] The improved price competitiveness between 2015 and 2016 is mainly attributed to lower commodity prices as well as an increase in BC Hydro rates at that time.

2025 Revenue Requirements Application[124], FEI expects this trend to continue in the coming years. As such, FEI assesses that, compared to the 2016 Proceeding, its energy price competitiveness risk has significantly increased.

Comparison with Other Jurisdictions

In this section, FEI compares its energy price competitiveness to other larger provinces in Canada. The energy cost advantage of natural gas over electricity has historically been, and continues to be, lower in BC relative to Alberta and Ontario, and greater in BC relative to Quebec. These differences are due to low electricity prices in BC and in Quebec with electricity rates in Quebec being the lowest in Canada. Figure A6-12 shows the extent to which residential electricity rates differ from province to province, with major cities represented.

Figure A6-12: Residential Energy Cost Differences between Natural Gas and Electricity[125]



Assumptions:

- Electricity rates are as per the Hydro-Québec Comparison of Electricity Prices in Major North American Cities for rates in effect April 1, 2021.
- The efficiency of gas equipment is assumed to be 92% relative to 100% for electricity to determine equivalent electric rates.
- Natural gas rates are as at April 1, 2021, so as to align with the Hydro Quebec report.
- Estimated bills are calculated based on annual use rate of 90 GJs.
- Natural gas bills are inclusive the applicable provincial or federal carbon tax and all bills are exclusive of other applicable taxes.

[124] https://www.bchydro.com/news/press_centre/news_releases/2021/rra-f23-f25.html.

[125] Please note that the monthly bills in this chart are based on estimated rates computed by Hydro-Québec and include fixed monthly charges as well as riders such as low-income assistance rate riders and cannot be readily compared with the amounts in Figure A6-11 above.

The relatively narrow energy cost advantage, along with BC Hydro's modest planned rate changes noted above, will make it more difficult for FEI to overcome obstacles to natural gas adoption when compared to utilities in Alberta and Ontario.

6.3.2 Carbon Tax Increases Continue to Erode FEI's Price Advantage

The carbon tax has had direct implications for the price competitiveness of natural gas as an energy source in BC since its inception in mid-2012, with an accelerating impact since the 2016 Proceeding. At the time of the 2016 Proceeding, there were no further carbon tax changes to be announced since the 2012 rate of $1.49/GJ was implemented. However, since that time, the federal government announced that it planned to require the provinces to have a price of at least $10 per tonne of carbon dioxide equivalent emissions starting in 2018. The carbon price would rise by $15 per tonne a year for the next eight years beginning in 2023, to reach $170 per tonne in 2030.The BC government has announced that it will enact changes in line with federal increases.

BC's carbon tax is currently set at $2.3053/GJ and by April 2022 will increase further to $2.5588/GJ; these levels are 55 percent and 72 percent respectively higher than the carbon tax rate in 2015. BC's historical carbon tax rates are provided in the table below[126]:

Table A6-1: BC Carbon Tax Rates for Natural Gas Since 2012

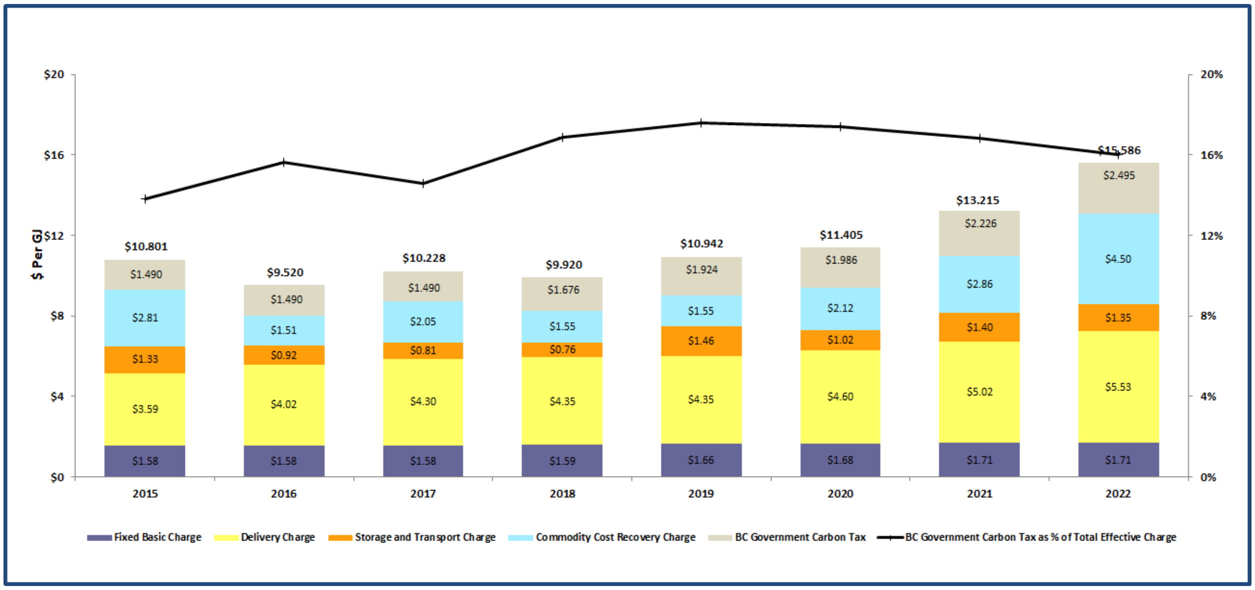
	July 1, 2012	April 1, 2018	April 1, 2019	April 1, 2021	April 1, 2022
Carbon Tax Rate ($/GJ)	1.4898	1.7381	1.9864	2.3053	2.5588

The carbon tax presents a competitive challenge for FEI as it is a discrete tax applicable to natural gas and other fossil fuels, but not to electricity.

Figure A6-13 below provides a breakdown of FEI's total effective rate for a typical residential customer. As shown, the share of carbon tax as a proportion of the total effective rate has increased from 13 percent in 2015 to 16 percent in 2022. Once the announced carbon tax increase to $170 per tonne is in place in 2030, the carbon tax rate will have increased by more than 5.5 times, to $8.40 per GJ.

[126] Ministry of Finance, Tax Schedule; Can be accessed at: https://www2.gov.bc.ca/assets/gov/taxes/sales-taxes/publications/carbon-tax-rates-by-fuel-type-from-july-1-2012.pdf.

Figure A6-13: Breakdown of FEI's Historical Total Effective Rate for Residential Customers



Assumptions:

- Natural gas use of 90 GJs per year assumed for Fixed Basic Charge.
- FEI rates and the BC carbon tax are weighted averages (where applicable), to reflect rate changes which occur throughout the year.
- All delivery and commodity rates are inclusive of applicable rate riders.

The continued increase of the share of this non-controllable item in customer bills hinders FEI's ability to manage the rate impact on its customers and reduces FEI's competiveness.

Moreover, two additional factors will further exacerbate FEI's energy price competitiveness in the coming years:

1. An increasing share of Renewable Gas in FEI's gas supply portfolio will cause further increases to its overall burner tip rates as discussed in Section 6.3.3 below; and
2. The increasing adoption of new electric technologies like electric heat pumps that have efficiency levels higher than 100 percent will increase the electric energy price advantage as discussed in Section 6.3.4 below.

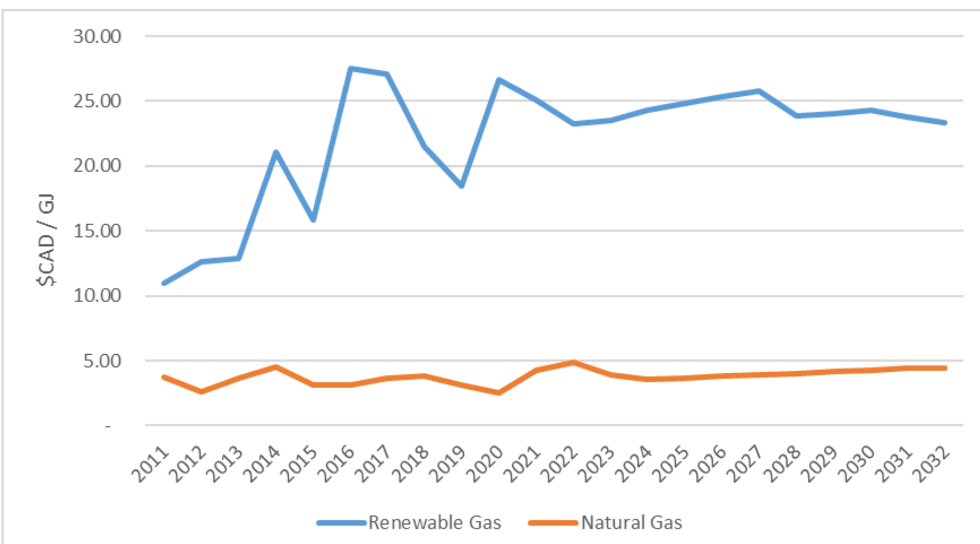
6.3.3 Renewable Gas Price Will Further Reduce FEI's Cost Competitiveness

Renewable Gas is an important part of FEI's initiatives to meet its GHG reduction targets. Nevertheless, the increased supply of Renewable Gas in FEI's supply portfolio brings its own risks. Renewable Gas is more expensive than natural gas and, as more is incorporated into FEI's energy portfolio, FEI's price competitiveness when compared to electricity or even FEI's current cost of gas, is reduced.

FEI has offered a Renewable Gas program since 2010 with cost recovery of the acquired RNG volume recovered from the voluntary program participants. In 2015, following BCUC approval, the cost recovery mechanism was revised such that approximately 50 percent of RNG acquisition costs were recovered from program participants and 50 percent from FEI's other non-bypass customers. In December 2021, FEI filed its Comprehensive Review and Application for a Revised Renewable Gas Program (Renewable Gas Application) which, along with other revisions, seeks to blend Renewable Gas volumes with natural gas to be sold to all sales customers as part of their gas service. As Renewable Gas supply increases to meet government emission reduction targets, FEI intends to flow that supply to all sales customers[127], and this supply will increase over time. As customers receive an increasingly greater portion of their gaseous energy as Renewable Gas, their gas costs will increase proportionally.

FEI acquires Renewable Gas through purchasing finished product from a producer/supplier or by purchasing raw biogas and upgrading it to a finished product. The Renewable Gas purchased from a producer/supplier is based on a negotiated price per GJ while the cost of Renewable Gas produced by FEI is based on the annual cost of service of the assets used to produce it. Both of these types of costs are used to calculate the average price of Renewable Gas supply. Figure A6-14 below sets out the actual average price per GJ of Renewable Gas supply through to the end of 2020 and a forecast from 2021 to 2032 compared to the cost of natural gas[128].

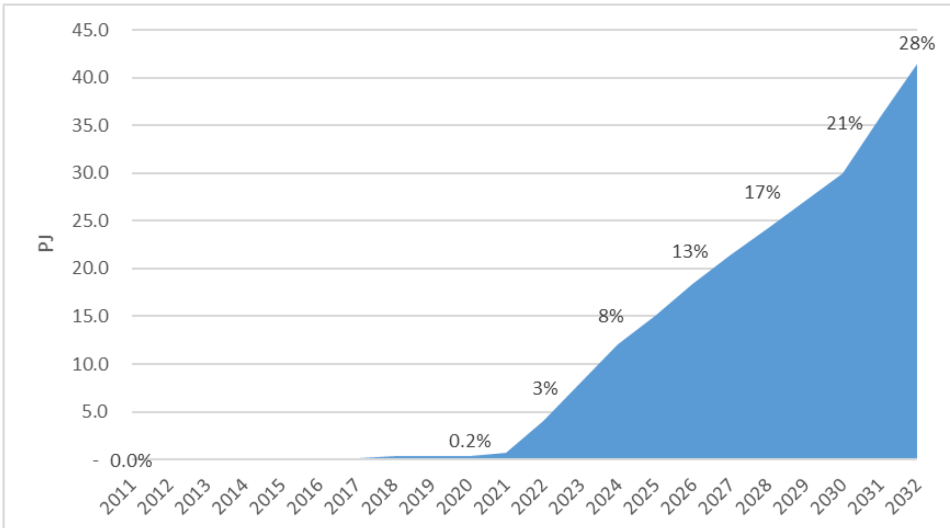
Figure A6-14: Renewable and Natural Gas Price[129]



[127] FEI's sales customers include those in RS 1,2,3,4,5,6 and 7.
[128] The cost of natural gas is an average of GJL and IHS from Figure A6-13 above converted to $CAD/GJ.
[129] FEI's Renewable Gas Application filed December 17, 2021.

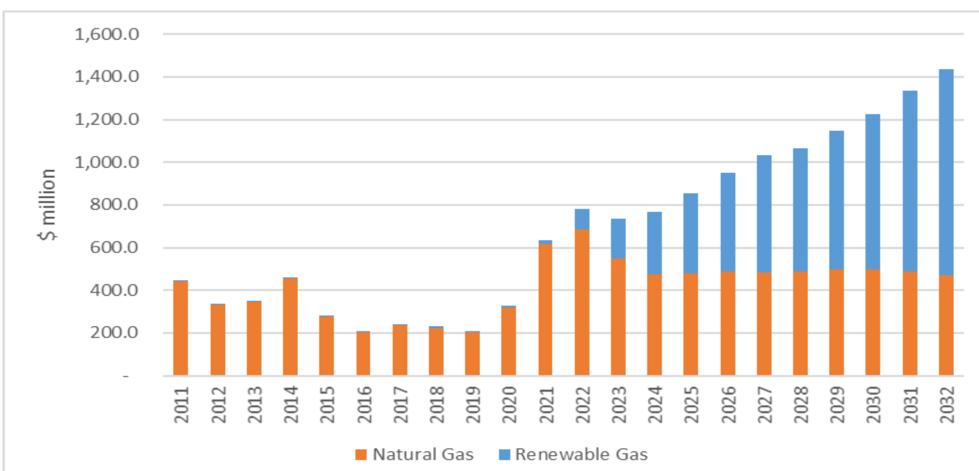
Figure A6-15 below represents the approximate percentage of Renewable Gas embedded in FEI's total gas supply, as FEI expands its volume of Renewable Gas in its system in response to climate action policy and regulation.

Figure A6-15: Volume and Percentage of Renewable Gas in FEI's Supply Mix



As the percentage of higher-priced Renewable Gas increases within the total mix of FEI's gas supply, the cost of gas will increase and those costs will need to be passed on to customers through higher rates. Figure A6-16 below shows the approximate total cost for both renewable and natural gas.

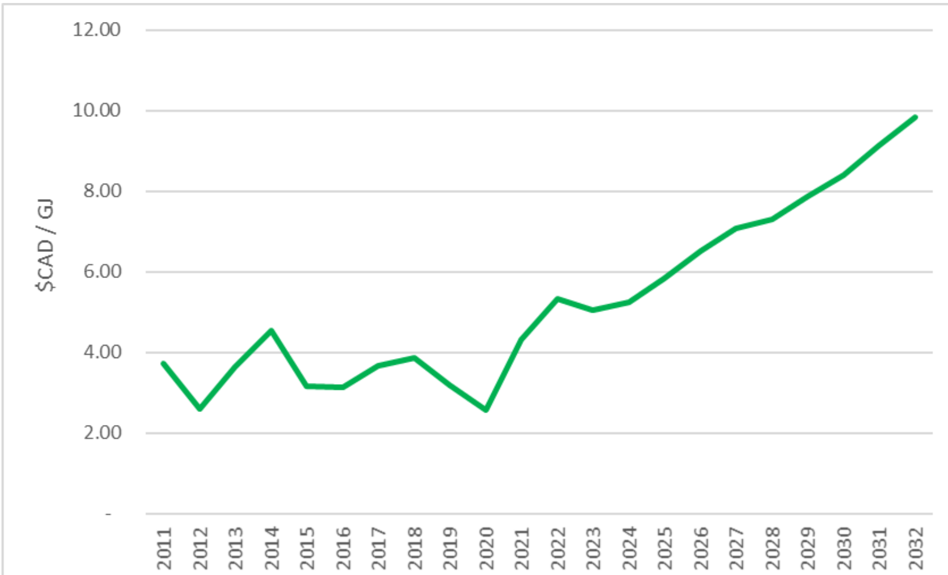
Figure A6-16: Increasing Cost of Incorporating Renewable Gas Cost in Supply Portfolio[130]



130 In this figure, FEI has used 2020 actual gas throughput and held it constant to 2032. As such, as Renewable Gas volume grows out to 2032, FEI has assumed it displaces natural gas volumes. The total Renewable Gas cost is

Summing the total cost of the blended gas supply and dividing it by the volume produces the cost of gas per GJ in Figure A6-17 below. Increasing the volume of Renewable Gas within FEI's supply mix, combined with Renewable Gas' higher unit cost, will result in an approximate 260 percent increase in FEI's total cost per GJ by 2032. FEI expects that by 2032, approximately 11 percent of the gaseous energy delivered to customers will be Renewable Gas, resulting in an incremental annual cost of approximately $330 for a residential customer consuming 83 GJs per year.

Figure A6-17: Weighted Average Cost of Gas (Renewable and Natural)



Decarbonizing FEI's gas supply in response to climate policy will cause the average cost of energy to increase (Figure A6-17). This rising cost of energy, regardless of specific cost recovery mechanisms or tariffs, will continue to be borne by FEI's customers, reducing FEI's price competitiveness when compared to other energy alternatives. This necessary growth in supply, at a level that was not supported or projected at the time of the 2016 Proceeding, increases FEI's energy price risk.

6.3.4 Price Competitiveness Based on Total Cost Has Decreased since 2015

Section 6.3.1 provided an overview of natural gas price competitiveness on the basis of average annual bill amounts. In this section, price competitiveness will be analyzed by also considering the upfront capital cost differences between gas and electricity end-use applications (space and water heating) for new construction, including the adoption of new technologies which support the use of electricity. In addition to capital costs, efficiency rates and maintenance costs affect the total cost of the appliance over its measure life. Gas appliances have typically higher capital and

determined by multiplying the Renewable Gas volume from Figure A6-16 above by FEI's Renewable Gas per GJ from FEI's Renewable Gas Application filed December 17, 2021. The total natural gas cost is determined by multiplying the natural gas volume as described herewith by the cost of natural gas from Figure A6-16 above.

Errata dated October 20, 2022

maintenance costs and lower efficiency rates, which decrease the total price competitiveness of gas versus electric alternatives. As discussed below, since FEI's last cost of capital proceeding, the price competitiveness of natural gas versus electricity has reduced, from both the energy price and total price perspectives.

Table A6-2 below provides the upfront capital costs and efficiency estimates for new construction that are used in FEI's total cost comparison analysis. For space heating, a gas furnace is compared with an electric baseboard heater, as well as an electric heat pump. An electric baseboard heater is the electric space heating alternative that was used in previous proceedings. However, as explained in Section 4.2.2.2.1, the electric heat pump is a relatively new space heating option (which also provides an attractive cooling option) that is being promoted by policymakers and is gaining market share[131], and therefore has been added to the space heating analysis.

As shown below, a gas furnace is considerably more costly than an electric baseboard heater yet less expensive than an electric heat pump.[132] For the purpose of this analysis, a new gas furnace is assumed to be 96 percent efficient, an electric baseboard heater is assumed to be 100 percent efficient, and an electric heat pump is assumed to be 200 percent efficient[133].

For water heating, similar to the 2016 and previous cost of capital proceedings, a gas hot water tank is compared with an electric water heater. Gas water heaters continue to be more costly than the electric alternative. The efficiency of a gas water heater is assumed to be 67 percent while the electric water heater tank is assumed to be 100 percent efficient.

Table A6-2: Upfront Costs and Efficiency Estimates for Space and Water Heating[134]

	Space Heating Options			Water Heating Options	
Equipment	Gas Furnace	Electric Baseboard	Electric Heat Pump	Gas Water Heater Tank	Electric Water Heater Tank
Capital Cost[135]	$18,000	$9,200	$21,000	$2,800	$1,550
Efficiency Rate	96%	100%	200%	67%	100%

To compute the total cost differential between gas and electric options, the upfront and installation cost differential is first converted into an annualized format using the builder's assumed interest

[131] According to FEI's 2017 REUS, 14 percent of new SFDs (constructed in 2016 or after) use an air source heat pump as their main space heating equipment.

[132] The provincial and municipal governments provide various rebates for electric heat pump to decrease the upfront costs and make it price competitive with a gas furnace.

[133] Electric heat pumps are often advertised to have 200 percent or even higher efficiency. However the actual efficiency of heat pumps may be lower than the nameplate efficiency depending on outside temperature and other factors.

[134] Cost estimates were provided to FEI by an independent consultant (Ecolighten Energy Solutions Ltd.).

[135] Both gas furnace and central heat pump cost estimates include the cost of ductwork that is usually contracted out to the sheet-metal contractor who does all the ducting and exhaust fans in a new home. Per BC Building Code, the electric baseboard cost estimate includes the cost of a mechanical ventilation system that would be needed in a house with no air-forced space heating system.

rate and measure life of the equipment. In the next step, the sum of the annualized upfront capital cost and annual maintenance cost[136] differentials are divided by the assumed space heating and water heating consumption levels for new construction to calculate the capital and maintenance cost difference per GJ.

As demonstrated in the table below, the cost difference per GJ between a gas furnace and an electric heat pump is negative, reflecting the fact that, all else equal, a gas furnace has a lower capital cost than a heat pump, but is not able to provide the cooling benefits of a heat pump. The cost differentials between a gas furnace and an electric baseboard, as well as between a gas water heater and an electric water heater, are positive (more costly) and higher than the previous cost of capital proceedings, reflecting higher capital cost estimates for gas appliances.

Table A6-3: Difference in Costs for Space and Water Heating over Measure Life[137]

	Space Heating (Gas Furnace)		Water Heating (Gas vs Electric)
	vs Heat Pump	vs Baseboard	
Difference in capital costs	**($3,000)**	**$8,800**	**$1,250**
Annual payments for recovery of capital costs	($257)	$753	$137
Difference in maintenance costs per year	$0	$100	$0
Total costs per year to pay off difference in capital cost	**($257)**	**$853**	**$137**
Energy consumption (GJ)	38	38	22
Difference in capital and maintenance costs between gas and electric Equipment ($/GJ)	**($6.8)**	**$22.4**	**$6.2**

Finally, the annualized capital and maintenance cost differentials are compared to the difference between FEI's burner tip rate[138] and efficiency adjusted electric rates[139]. If the operating cost advantage of natural gas (calculated as the difference between FEI's burner tip rate and efficiency adjusted electric rates) is greater than the difference in capital and maintenance costs between gas and electric options, then the natural gas equipment is assumed to be the more economic option for the consumer. However, if the natural gas operating cost advantage is smaller than the

136 Manufacturers may recommend a certain maintenance schedule however homeowners may not always follow these recommendations. As such, annual maintenance cost is situational and can change from one household to the other. These numbers are FEI's best estimates.

137 Assumptions based on the new construction of a home in the Lower Mainland (Medium Size Dwelling), interest rate of 5 percent and the measure life of 18 years for a gas space heating furnace and 13 years for hot water tank. The annual payments to recover the difference in upfront capital costs are calculated based on the present value of an annuity formula where PV of an annuity = annuity * [(1-(1+r)^-n)/r] (r is interest rate and n is the measure life of the equipment).

138 FEI burner tip rate includes the commodity charge, storage and transport charge, fixed basic, and delivery charges, and the carbon tax to provide a comparison against the electric equivalent (based on an average annual use rate of 90 GJ per year).

139 To calculate the electric equivalent rate, the electric to gas efficiency ratio is applied to the Step 1 and Step 2 BC Hydro RIB rate. For example to compare a gas furnace with an electric heat pump, the assumed 96 percent efficiency of a new gas furnace is divided by the heat pump's assumed efficiency of 200 percent and multiplied with Step 1 and Step 2 rates.

upfront capital and maintenance cost differential, then the electric option will be more economical. The results of this analysis are shown in the table below.

Table A6-4: Operating Cost Advantage vs Capital Cost Differential between Gas and Electric Equipment[140]

	Space Heating (Gas Furnace)		Water Heating (Gas vs Electric)
	vs Heat Pump	vs Baseboard	
BCH Step 1 Rate Adjusted for Efficiency	$12.3	$24.7	$17.2
BCH Step 2 Rate Adjusted for Efficiency	$18.5	$37.0	$25.9
FEI's Burner Tip Rate	$15.6	$15.6	$15.6
FEI's Operating Cost Advantange vs BCH Step 1 Adjusted Rate	($3.3)	$9.0	$1.6
FEI's Operating Cost Advantange vs BCH Step 2 Adjusted Rate	$2.9	$21.4	$10.2
Difference in capital amd maintenance costs between gas and electric Equipment ($/GJ)	($6.8)	$22.4	$6.2

The results can be summarized as follows for each of the three columns shown in Table A6-4.

Gas Furnace as Compared to Electric Heat Pump

Due to low market penetration at the time, FEI did not analyse the relative competitiveness of a gas furnace as compared to a heat pump in the 2016 Proceeding. The analysis above shows that a gas furnace is less costly than a heat pump, with the difference estimated at $6.80 per GJ over the measure life. BC Hydro's efficiency adjusted Step 2 rate is $2.90 per GJ higher than FEI's burner tip rate and its Step 1 rate is $3.30 per GJ lower; therefore, without a means of reducing the heat pump's high capital costs, the gas furnace option will be more economic. Currently, both provincial and local governments as well as BC Hydro provide generous rebates to households who install heat pumps and/or convert their fossil fuel heating systems to central heat pumps[141]. As such, when the heat pump's higher rebates are considered, the gas furnace's cost advantage can be reduced or eliminated in favour of the electric heat pump, depending on the rebate amount.

Gas Furnace as Compared to Electric Baseboard

Due to increasing capital costs for gas furnaces and a reduced differential between gas and electric rates, the relative competitiveness of natural gas when including the upfront capital costs of installation has decreased since the 2016 Proceeding. The table above shows that a gas furnace is significantly more costly than electric baseboard heating, with the difference estimated at $22.40 per GJ over the measure life. The upfront capital costs associated with the installation of a gas furnace eliminates FEI's competitive position against both Step 1 and Step 2 efficiency-adjusted electric rates as FEI's operating cost advantage over both Step 1 and Step 2 efficiency-adjusted rates is less than $22.40 per GJ. This price advantage in favour of electricity is even

[140] Based on FEI's Approved Rates for 2022 and BC Hydro's proposed rates in its 2023-2025 RRA.
[141] Please refer to: https://betterhomesbc.ca/rebates/cleanbc-new-construction/. Refer also to footnote 32.

more persuasive when considering smaller multi-family dwellings (MFDs), such as townhouses and apartment units, that are more likely to have electric baseboards as their main space heating. For these units, lower consumption means lower savings in annual energy costs to offset the higher capital cost of a gas furnace.

Gas as Compared to Electric Water Heating

Due to a reduced differential between gas and electric rates, the relative competitiveness of natural gas water heating has decreased since the 2016 Proceeding. The table above shows that gas water heating is somewhat more costly than electric water heating, with the difference estimated at $6.20 per GJ over the measure life. The upfront capital costs associated with the installation of a gas water heater eliminates FEI's competitive position against the Step 1 efficiency adjusted rate and greatly reduces its competitiveness with efficiency-adjusted Step 2 rate.

In summary, since FEI's last cost of capital proceeding, the price competitiveness of natural gas versus electricity has reduced, from both the energy price and total price perspectives. The capital cost differentials have increased, decreasing FEI's total price competitiveness. Electric heat pumps have higher upfront capital costs but the current government rebates funded by taxpayers' money effectively change the price advantage in favour of heat pumps. Further, the steady increase in carbon tax, as well as increases in natural gas and Renewable Gas costs, will further reduce FEI's price competitiveness in the coming years.

7. DEMAND/MARKET RISK

The choice of energy, and how it is consumed and produced, is influenced by changing customer perceptions of energy, the introduction of new technology and energy forms, and building type and age, among other things,. Demand and market changes in these areas continue to pose challenges to FEI's ability to attract and retain customers, and maintain market share and throughput levels. Overall, FEI's analysis indicates that the risk associated with demand and market shift away from natural gas is greater than what was assessed in the 2016 Proceeding.

When comparing to the 2016 Proceeding, the main points discussed in the following sections are:

- Section 7.1 discusses the increased risk associated with the perception of energy in BC, and natural gas in particular.
- Section 7.2 explains how new technology and new sources of energy are being considered to advance climate solutions and these present an increased risk.
- Section 7.3 discusses FEI's challenges in achieving positive net customer additions and how the risk associated with these additions has increased, in part due to an increase in tear down rates.
- Section 7.4 describes changes in building types and capture rates in various building segments and how, compared to 2015, this dynamic poses a similar risk to FEI.
- Section 7.5 outlines the downward trend in the natural gas end-use market for space heating and water heating applications that points to FEI's increased risk.
- Section 7.6 explains how changes in use per customer present a similar risk to FEI as in the 2016 Proceeding.

7.1 *PERCEPTION OF ENERGY HAS SHIFTED AGAINST NATURAL GAS*

FEI's assessment is that the risk associated with the perception of energy and natural gas in particular among BC residents has increased.

Historically, customer energy choices tended to be driven by market factors such as energy price, accessibility, ease of use, reliability, and availability. However, BC residents' energy choices are increasingly influenced by a desire to use energy efficiently, to adopt lower carbon and renewable energy sources and to generally reduce the negative impacts of climate change (refer to Section 4.1). This creates challenges for natural gas utilities in retaining and attracting load, despite lower natural gas commodity prices relative to other energy forms.

FEI has conducted a number of surveys and studies since the 2016 Proceeding. Figure A7-1 summarizes key findings from recent FEI surveys that were undertaken to understand how consumers perceive their home energy options.

Figure A7-1: Summary of Customer Perception Research

The 2020 Energy Preferences Survey

- The study was similar to the 2012 and 2013 Energy Source Usage Preferences Studies. The survey measured current residential energy sources and also future energy sources among 1200 BC residents in the FortisBC service territory.
- Similar to the earlier studies, the survey found that most residents currently use natural gas (42%) or electricity (43%) as their primary space heating; however, when asked which energy sources they would install in a new home for space heating, four in-ten would opt for geothermal (20%) or solar (19%). The various energy options were presented without reference to the cost of installation or operation.
- Affordability (37%) and the environment (34%) were the two top reasons for choosing a space heating fuel.

The 2018 Natural Gas Attitudes Survey

- The survey was conducted online with 1300 BC residents.
- Participants were divided equally about the right balance between making progress in reducing greenhouse gas emissions and limiting the increase in costs to consumers with 46% of survey participants believing the priority should be the environment and an equal percentage saying the priority should be cost.
- Four-in-ten participants agreed that Governments should phase out the use of natural gas because the burning of natural gas produces carbon dioxide. Only one-quarter opposed the idea. Nearly one-half (45%) believe that it would be relatively easy to meet all of BC's energy needs using renewable electricity.

Communications Tracking Study 2017 – 2021

- Measures BC residents' awareness of FortisBC's communications efforts. The survey is conducted three times per year with 800 participants per wave.
- The study shows that despite the termination of the Gas is Good campaign, approximately one-third of BC residents are at "Extremely Receptive" or "Very Receptive" to natural gas.
- Similar to the findings from the 2020 Energy Preference Study, while greater than one-in-four participants use natural gas for home heating, only one-third would chose to use it in a new home. Four-in-ten would opt for solar (16%), heat pump (12%) or geothermal (11%).

As can be seen, affordability and environment are the two main factors that influence existing customers' energy choices, whereas, the results for that same study in 2012 and 2013 indicated that perceived reliability and safety of the energy source were the primary influencers of customers' energy choices. Furthermore, looking into the future, nearly half of the respondents believe that it would be relatively easy to meet all of BC's energy needs using renewable electricity with two-thirds supporting or being open to phasing-out the use of natural gas for environmental reasons. This shift against natural gas, and the influence that the environment and negative impacts of climate change now have on customers' energy choices, has increased FEI's risk associated with the perception of energy.

7.2 INCREASING ADOPTION OF NEW TECHNOLOGY AND ENERGY FORMS THAT REDUCE NATURAL GAS USE

Increasingly, climate-centric technologies and new sources of energy are being considered or used by policy makers and companies alike to advance climate solutions and achieve GHG emission reduction targets. These technologies range from all-electric solutions, such as electric heat pumps, to other solutions, such as high-efficiency gas heat pumps and renewable gases. In this section, FEI will discuss the major technologies that can negatively affect FEI's demand in its core business of providing natural gas for space and water heating. FEI's assessment is that new technologies present a higher risk for FEI today relative to the level of risk assessed in the 2016 Proceeding. FEI also describes the role of Renewable Gas for customers to achieve GHG emission reduction targets and how its demand is being impacted.

The application of existing alternative technologies and the introduction and adoption of new technologies and energy forms in the building sector can impact FEI's demand profile and throughput levels in two major ways.

First, new technologies such as high-efficiency electric heat pumps can directly displace both existing and future demand for natural gas. As discussed in the Roadmap, compared to the other existing alternatives, heat pump technologies are more than twice as efficient and can also be used as air conditioners in increasingly hot summers[142]. Electric heat pumps are gaining in market share, with options available for all major building types and climates. This includes electric mini-splits, multi-splits, electric central, air-to-water and combination space and water systems or electric air source heat pump water heater systems. As discussed in Section 6.3.4, compared to a natural gas furnace, heat pumps have higher upfront capital and installation costs; however, there are significant subsidies available to offset heat pumps costs and further increase their adoption[143].

Government policy anticipates moving beyond financial incentives favouring electric heat pumps. The Roadmap states that "after 2030, all new space and water heating equipment sold and installed in BC will be at least 100% efficient, significantly reducing emissions compared to current combustion technology[144]". This policy clearly targets the high-efficiency natural gas furnace market and effectively bans installation of natural gas furnaces after 2030, since unlike heat transfer technology used in heat pumps, combustion technology used in natural gas furnaces to produce heat cannot become 100 percent efficient. Government policy precluding new buildings from using natural gas in this manner creates significant risk for FEI.

[142] CleanBC Roadmap to 2030, p. 39.

[143] For example, in Vancouver, a gas customer can get upwards of $10,000 in combined incentives to decommission their existing gas heating equipment and replace it with an electric heat pump. In order to qualify, the source of heat back up cannot be a "fossil fueled" device. In addition BC Hydro's recently published Electrification Plan builds on existing BC Hydro and provincial rebates and customer supports for the installation of heat pumps and provides an additional incentive of up to $3,000 to customers to switch to electric heat pumps.

[144] CleanBC Roadmap to 2030, p. 41.

The high efficiency of heat pumps, their dual function for heating and cooling, as well as governments' material financial subsidies, will challenge FEI's ability to add new customers or retain existing ones. In the case of existing customers, the implications are significant over time. For example, when a gas furnace comes to the end of its useful life and must be replaced, it was traditionally replaced with a similar, but more up-to-date and increased efficiency natural gas appliance. Heat pumps have not historically been a significant threat due to the incremental cost associated with the equipment and installation. Now, with the trend toward warmer summers, heat pumps have become more attractive to home owners, with the ability to offer cooling as well as heating. This additional functionality, along with the considerable rebates from various levels of government, means that the incremental cost of installing a heat pump as an alternative to a gas furnace has been dramatically reduced or in some cases eliminated.

While FEI does not have definitive figures, it is estimated that somewhere between 5 percent and 10 percent of all residential customers will be faced with replacing their heating equipment in any given year. It is at this point where FEI is most vulnerable to potentially losing the heating load to electricity. In the future, gas-fired heat pumps may be able to compete with electric heat pumps; however, gas-fired heat pumps are still in their pilot phase and not used on a commercial scale[145].

Second, the changing landscape of technologies influences codes and regulations and building design and controls, which can have an impact on energy use and energy choice. This shift to higher efficiency homes will reduce use per customer (UPC) and gas throughput. Furthermore, the building code measures favour electric heat pumps due to their higher efficiency. As explained in Section 4.2.3.2, the Step Code, is an example of how new technology developments impact building codes and design. The Step Code, is a long-term, graduated approach to meeting climate action targets. It sets higher requirements for energy efficiency in new construction than the base BC Building Code. It consists of a series of up to five levels or "steps," each representing increasing levels of energy-efficiency performance[146]. By adopting one or more steps over time, local governments can gradually increase the building performance requirements in their communities, eventually achieving net-zero in new construction by 2032. In all cases, building to the Step Code means builders must meet the energy use measures defined for each step and these measures favour electric heat pumps due to their higher efficiency.

Renewable Gas provides an alternative to hydro-generated electricity from an emissions reduction perspective and would meet new code and regulation requirements. However, there is a general lack of awareness and acceptance from customers and stakeholders as to the role Renewable Gas plays in reducing emissions when compared to electricity. The lack of acceptance

[145] Compared to electric heat pumps, gas-fired heat pumps have lower name plate efficiency which make them less favourable from policy makers' perspective.

[146] The BC Energy Step Code identifies energy-performance targets that the building must meet for each step. There are five steps identified for Part 9 buildings which refer to housing and small buildings (that are up to three storeys in height and an area not exceeding 600 m2 in area) and four steps for Part 3 buildings which refer to commercial and multi-family buildings that exceed three storeys or exceed 600 m^2 in area.

of Renewable Gas, from customers and stakeholders is largely driven by the perception that is a bridge fuel and potentially not a long term emissions reduction.

Hence, there is a risk of some customer segments choosing other lower emissions energy sources rather than Renewable Gas to meet their need for low carbon or carbon neutral energy sources. FEI currently has an application before the BCUC, with proposals developed to respond to evolving government climate policies, customer needs for Renewable Gas, and the significant increase in Renewable Gas that FEI is acquiring pursuant to the GGRR. By way of this application, FEI proposes to maintain the option for customers to choose Renewable Gas blends that meet their emissions reduction needs, as some customers are required to reduce the carbon intensity of the energy they consume due to regulation while others may be interested in doing so to suit their own sustainability objectives. To reduce GHG emissions, large commercial customers have a range of alternatives available to achieve their internally or externally mandated emissions reduction targets. The available alternatives include purchased carbon offsets, investments in energy efficiency, fuel switching to electricity or opting into Renewable Gas service. Moreover, all of these alternatives can be combined in ways to suit the needs of their buildings or their budgets. For example, a customer could choose to electrify their domestic hot water heating, while replacing their conventional space heating furnace with a higher efficiency model, and subscribing to 100 percent Renewable Gas.

The increased adoption of electric heat pump technology coupled with their dual use for heating and cooling, is emerging as a major threat to FEI's core business of space heating and water heating. Despite the role that Renewable Gas can play, the risks discussed above will impact demand and FEI's ability to retain or grow its customer base, increasing its business risk. In addition, the changing landscape of technologies and building techniques being reflected in more stringent energy step codes adopted by local governments will likely reduce the use per customer or in some cases hinder FEI's ability to connect customers to the natural gas network completely. As such, FEI submits that compared to the 2016 Proceeding, the development of new technologies has resulted in an increased level of risk to FEI.

7.3 *DECLINING NET CUSTOMER ADDITIONS POINT TO FEI'S INCREASED RISK*

FEI's ability to manage risk is in part dependent on its ability to grow its customer count to offset the rate impact on customers due to declines in UPC and/or cost increases. This is because the residential customer additions are influenced by a number factors that have become more prevalent and some are outside of FEI's direct control.

Customer net additions growth requires a focused and sustained effort and will become even more difficult in the future than it has been historically. FEI's assessment is that in the coming years, achieving positive net customer additions, particularly in the residential customer segment, presents a higher risk for FEI than what was assessed in the 2016 Proceeding.

Net customer additions is a measure of gross additions (a new service to a new customer) less discontinued services. The table below provides the historical net customer addition numbers categorized by residential, commercial and industrial segments of FEI's business.

Table A7-1: FEI's Net Customer Additions by Segment and in Total

Year	2015	2016	2017	2018	2019	2020	2021
Residential	12,508	11,359	13,357	19,257	10,609	12,995	10,241
Commercial	1,673	965	1,060	1,794	610	386	479
Industrial	51	6	22	16	50	19	10
Total	14,232	12,330	14,439	21,067	11,269	13,400	10,730

As can be seen, the total net additions peaked in 2018 at over 21 thousand customers; however, this was followed by lower net customer additions in the 2019-2021 period. FEI expects this downward trend to continue in the following years.

The residential customer segment is the largest portion of FEI's total customer additions and dictates the trend for the total net additions. This can lead to large decreases to total net customer additions (and possibly negative customer additions) since most government initiatives to advance GHG reduction policies in the residential building sector are focused on electrification. The trend in residential net additions, and the percentage of new residential attachments it represents are depicted in the figure below. As shown, FEI's residential net customer additions peaked in 2018 at over 19 thousand (representing approximately 94 percent of the total number of new residential attachments). However, this was followed by lower than average net customer additions[147] in the following three years with FEI adding on average a little over 11 thousand residential customers (net of attrition), which represents approximately 64 percent of the number of new residential attachments in the same period. This indicates that in the last three years the pace of residential customers leaving FEI's system is greater than the pace of new customers being added, which points to the fact that government policies and other factors described below, and throughout this evidence, are already having a negative impact on FEI's business, increasing market risk.

[147] The average number of net customer additions for the 2015-2021 period is about 12,900, representing 1.4 percent of total number of customers in the period.

Figure A7-2: FEI's Residential Customer Additions

Residential customer additions are influenced by a number of factors, including technological changes (shift to electric heat pumps), the construction market in BC (growing MFD segment where FEI has relatively lower capture rates), declining price competitiveness of natural gas versus electricity due to the factors discussed in Section 4.2.2, government policies and incentives, such as carbon pricing or electrification rebates which can significantly impact the cost to customers. This market sector is also heavily influenced by municipal government policy where GHGi targets are being imposed as part of the building permitting process as is discussed in Section 4.2.2.1.4. In situations where these targets are applied, the implications range from a dramatic reduction in throughput due to gas heating and hot water equipment not meeting the imposed GHGi targets, to elimination of gas service all together. In addition, and as discussed in various sections of this appendix, FEI expects that the policies under the Roadmap, such as new high efficiency standards requiring space and water heating equipment to meet or exceed 100 percent efficiency by 2030, will significantly impact FEI's ability to add new customers and retain existing ones. This in turn, will negatively impact FEI's net additions, possibly leading to negative net residential additions in the coming years.

7.3.1 BC's High Turnover Rate on Older Buildings Exacerbates the Challenge to Achieve Positive Net Additions

Dwelling vintage and building stock turnover rate are good indicators of FEI's future capture rates, UPC and customer additions. Considering government policies to curb GHG emissions in new construction and in the retrofit market which can significantly impact FEI's ability to add new customers and/or retain existing ones, the large share of older dwellings in FEI's residential customer base is becoming a bigger risk and is an indicator of future challenges to capture rates, UPC and customer additions.

Due to various building code requirements for renovations, strong demand for housing, and limited space, it is often in the best interest of a building owner to tear down rather than improve a structure, thereby obtaining a greater return on investment (for a builder or developer) or an easier process (in the case of a homeowner). Because of a combination of factors, it is estimated that BC has a teardown rate nearly double the national average, at approximately two percent in 2020[148]. At this teardown rate, within 50 years all of the building stock that exists today would be replaced.

Table A7-2 below summarizes the distribution of FEI residential gas customers by dwelling vintage (period of construction), taken from FEI's Residential End Use Study (REUS).

Table A7-2: Dwelling Vintage by Region

Vintage	LM	INT	VI	FN	FEI
Before 1950	8.3%	9.7%	12.7%	2.5%	9.2%
1950-1975	25.0%	26.7%	18.9%	27.0%	24.7%
1976-1985	18.7%	15.0%	9.6%	25.4%	16.6%
1986-1995	20.6%	17.8%	16.6%	13.1%	19.3%
1996-2005	13.0%	14.9%	21.1%	17.2%	14.5%
2006-2015	10.7%	11.2%	18.0%	11.5%	11.7%
2016 or newer	1.1%	1.9%	1.2%	0.0%	1.3%

As can be seen, close to 35 percent of FEI's residential customers live in dwellings that are built prior to 1975 (compared with 37.5 percent in 2012). If the 50 year turnover discussed above holds true, FEI can reasonably project that more than one third of dwellings that are currently connected to FEI's natural gas system may be demolished and replaced with new ones.

The government policies at provincial and local levels that have been introduced since the 2016 Proceeding, discussed in Sections 4.2.2, 4.2.3 and 7.2, will make it very hard, if not impossible, for FEI to retain all of these customers causing net customer additions to drop.

7.4 *BUILDING TYPES AND CAPTURE RATES RELATIVELY UNCHANGED*

In this section, changes in building type and capture rates and their impact on FEI's risk profile are discussed. Compared to 2015, the MFD segment makes up a larger proportion of FEI's customer attachment, and FEI's capture rates in MFDs, particularly townhouses, have improved. However, FEI's capture rate in SFDs has declined, such that FEI's overall capture rate is similar

[148] Teardown rate from FEI's 2021 Conservation Potential Review.

to 2015 levels. As such, FEI's assessment is that the risks associated with the changes in building type and capture rates are similar to the levels assessed in 2015, with the expectation that FEI's capture rate will gradually decrease in the coming years due to government policies which promote electric-only solutions in the building sector.

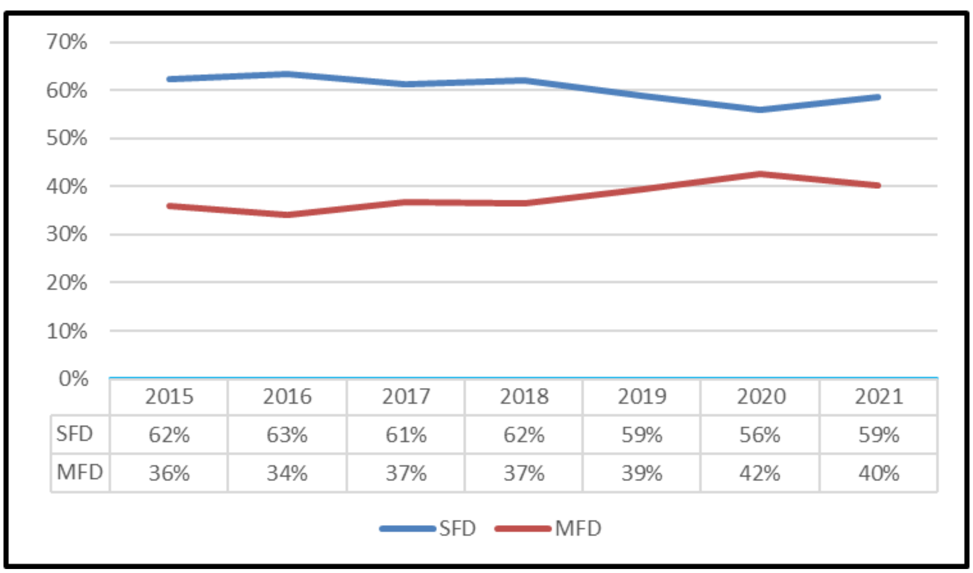
As presented in the table below, in FEI's 2017 REUS, the single family detached segment dominates FEI's residential customer base, accounting for 80 percent of all dwelling types in 2017. However, its share has been gradually declining over time as other dwelling types, notably townhouses, apartments/condominiums, and mobile homes have increased their share of FEI's customer base.

Table A7-3: Trend in Dwelling Type

Dwelling Type	REUS Year		
	2008	2012	2017
Single Family Detached	83.0 %	81.9 %	79.6 %
Semi-Detached	5.0 %	5.0 %	5.5 %
Row / Townhouse	8.2 %	8.4 %	9.6 %
Apartment / Condo	1.1 %	1.2 %	2.1 %
Mobile and other	2.7 %	3.6%	3.2 %

The same trend can be seen in FEI's new attachment segment. As demonstrated in Figure A7-3 below, the majority of FEI's new attachments are still in the SFD segment, however, looking at the trend it can be observed that the share of SFDs in FEI's new residential attachments is declining.

Figure A7-3: Percentage of New Residential Customer Additions by Building Type

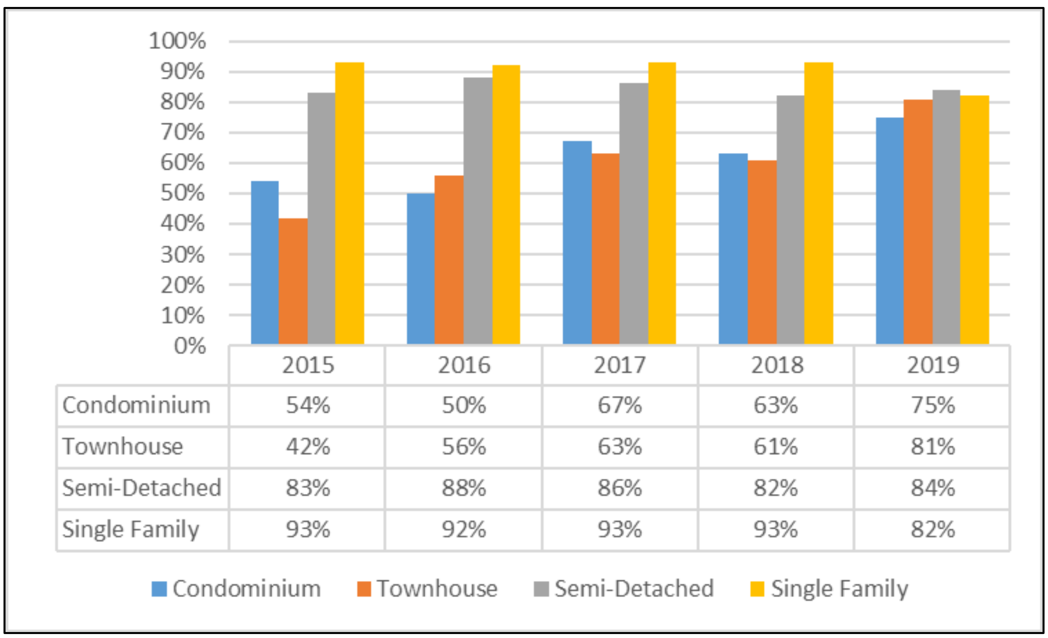


There are two key implications for FEI of the increased proportion of MFDs in the housing mix.

First, the annual consumption for natural gas is greater in SFDs than in MFDs. All else equal, an increase in the percentage of MFDs in FEI's residential customer mix will lead to a decline in residential UPC and overall residential throughput which, all else equal, results in higher rates for all residential customers.

Second, while FEI's efforts to improve its capture rate in the MFD market have been successful, natural gas continues to have a lower penetration rate in some segments of MFDs. Figure A7-4 provides the change in FEI's capture rates by housing types. As can be seen, between 2015 and 2019, capture rates in condominium and townhouse segments have increased with the townhouse segment reaching the same level as SFDs. However, the condo building segment is still lower than other segments and, excluding the 2019 data, the capture rate for detached and semi-detached homes is still higher than both townhouse and condominium segments of the market.

Figure A7-4: FEI Capture Rates by Housing Type



	2015	2016	2017	2018	2019
Condominium	54%	50%	67%	63%	75%
Townhouse	42%	56%	63%	61%	81%
Semi-Detached	83%	88%	86%	82%	84%
Single Family	93%	92%	93%	93%	82%

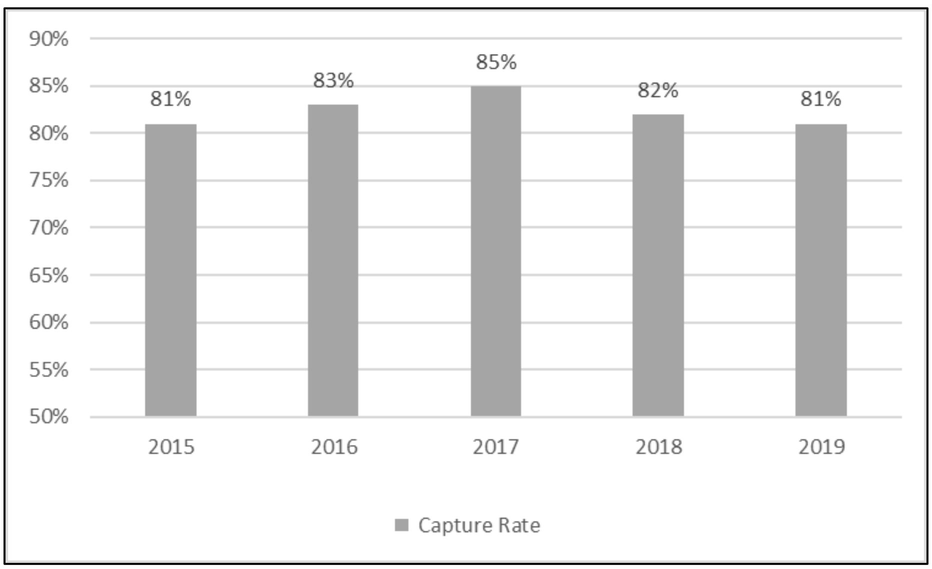
The lower capture rate for MFDs, particularly in the condo/apartment segment, is primarily driven by the unfavourable economics of installing a natural gas application as compared to an electric equivalent.[149] This is especially true for developments where the unit cost plays a primary role in the purchasing decision. In general, developers have a strong incentive (see Section 4.2.3.2.2) to install either electric baseboard or electric mini-split heating and cooling systems for MFDs, as opposed to natural gas, given the ever increasing demand for air conditioning and comparatively

[149] American Gas Association. Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges, p. 36.

high capital costs of natural gas heating appliances, ducting and overall installation costs. Natural gas space heating equipment also occupies valuable living space within a multi-family unit which could otherwise reduce a developer's return. In addition, the significant increase in the construction of Purpose Built Rental Apartments (PBRAs) has exacerbated this issue. The vast majority of PBRAs are designed to be constructed at the lowest capital cost, which, in many cases results in an "all electric" solution for both heat and hot water.

Irrespective of the dwelling type changes over the longer term, FEI expects its overall capture rate to decline. Indeed, as shown in Figure A7-5 below, FEI's overall capture rate peaked in 2017 and in 2019 returned back to the 2015 levels. As explained in various sections of this evidence, the provincial and local governments' preferential treatment of electric-only solutions in the building sector, coupled with technological advantages of electric heat pump technologies, will negatively impact FEI's ability to add new customers and/or retain existing ones. Going forward, these developments will negatively affect FEI's capture rates.

Figure A7-5: FEI Overall Capture Rate Trend



7.5 *FEI CONTINUES TO EXPERIENCE A DECLINE IN END-USE MARKET SHARE*

The majority of FEI's demand comes from space heating and water heating applications in the residential sector. As part of FEI's 2017 REUS, FEI asked its consultant, Sampson Research, to conduct detailed surveys that, among other things, gathered data on its end-use market. The REUS indicates that both space heating and water heating end-use markets are facing stiff competition from electricity, and FEI's market share is experiencing a downward trend, although in recent years, the pace of decline in the water heating market has been greater than the space heating market.

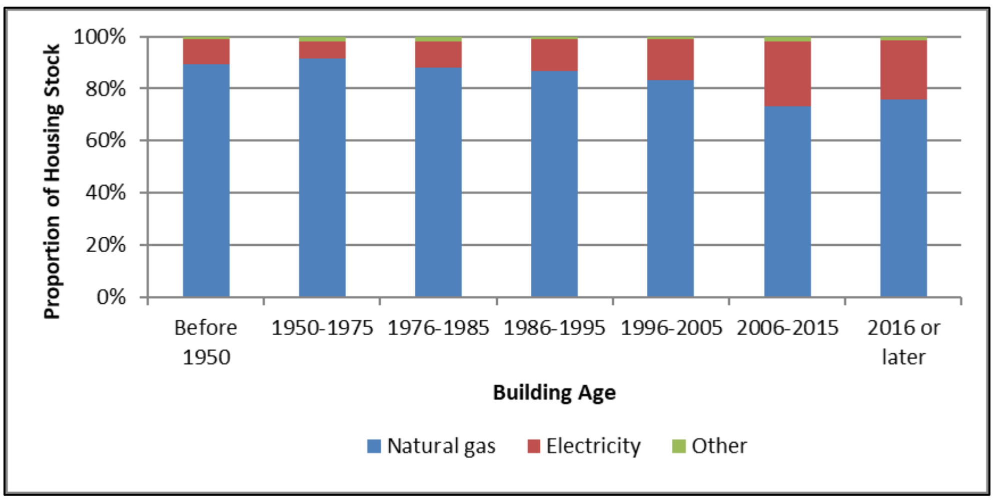
Table A7-4 below summarizes the main space heating fuel used by FEI's residential customers. The REUS indicates that, compared to the 2012 REUS that was incorporated in the 2016 Proceeding, the use of natural gas as a main space heating fuel is still diminishing.

Table A7-4: Space Heating End-use by Fuel Type in FEI's Service Territory

Fuel Type	REUS Year		
	2008	2012	2017
Electricity	7%	11%	12%
Natural Gas	91%	87%	86%
Other	2%	2%	2%

Figure A7-6 below illustrates the main space heating fuel trend by dwelling age for residential customers.

Figure A7-6: Natural Gas Use for Residential Space Heating by Building Vintage



Source: 2017 Residential End-use study

The REUS report provides the following comments on the above trend:

> Of note, the relative share of dwellings using natural gas as their main space heating fuel began declining in the 1990s. For example, 87% of homes constructed between 1986 and 1995 use natural gas as the main space heating fuel compared to 73% of homes constructed between 2006 and 2015. In its place, electricity is now the main space heating fuel for approximately one-quarter (25%) of all dwellings constructed since 2006. The shift from natural gas to electricity reflects, in part, increased penetration of air source heat pumps and electric baseboards in newer dwellings. The slight increase in gas share for homes built since 2015 is not statistically significant at the 95% confidence level.

Errata dated October 20, 2022

The same trend is occurring for domestic water heating (DWH), which constitutes the second largest share of natural gas use for residential customers. The table below summarizes the percentage of natural gas, electricity and other fuel types in FEI's service territory based on the surveys conducted in the last three residential end-use studies.

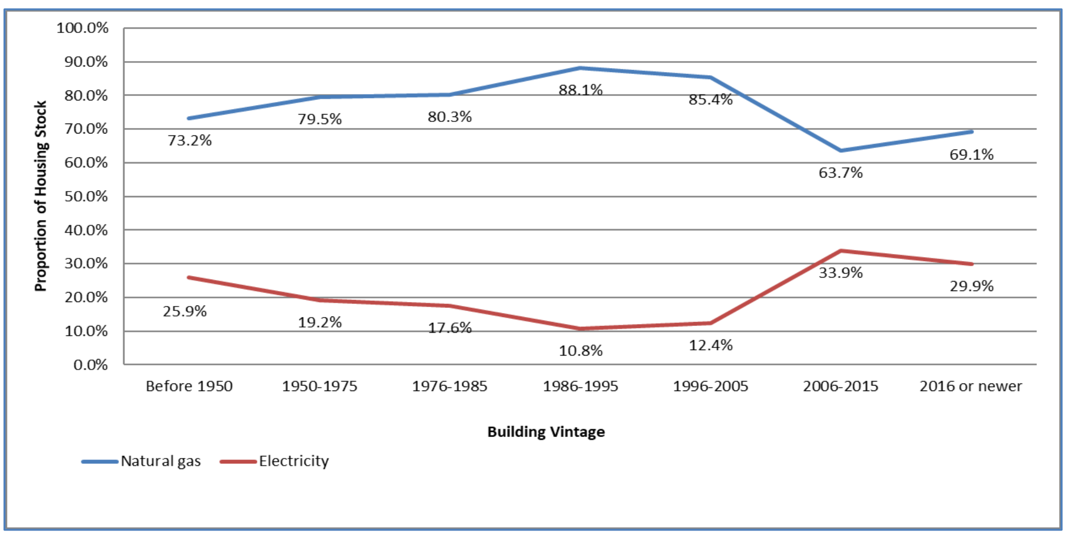
Table A7-5: Water Heating End-use by Fuel Type in FEI's Service Territory

Fuel Type	REUS Year		
	2008	2012	2017
Electricity	11%	17%	20%
Natural Gas	89%	83%	78%
Other	0%	1%	2%

The data shows the continued movement away from natural gas to electricity for residential DWH. Specifically, the percentage of dwellings using natural gas for DWH in 2017 was 78 percent, down from 83 percent in 2012 and 89 percent in 2008.

According to the REUS, newer homes with gas service are less likely to use natural gas-fired DWH and more likely to use electricity compared to the stock of homes built prior to 2006. Figure A7-7 below illustrates the trend in DWH fuel by dwelling age for SFDs.

Figure A7-7: Residential Domestic Water Heating Fuel by Dwelling Vintage



Source: 2017 Residential End-Use Study

The REUS report explains the above trend as follows:

> The data shows the proportion of SFDs using natural gas for DWH (main unit) peaked between 1986 and 1995 (88% of SFDs constructed during these years) but has declined in newer dwellings. Notably, two-thirds (64%) of SFDs

constructed between 2006 and 2015 use natural gas as their DWH fuel. Although the share for natural gas DWH appears to have increased for dwellings constructed since 2015, the increase over 2006-2015 is not statistically significant at the 95% confidence level.

As space heating and DWH together account for the majority of total residential natural gas consumption, the declining trends discussed above will negatively impact throughput and load growth.

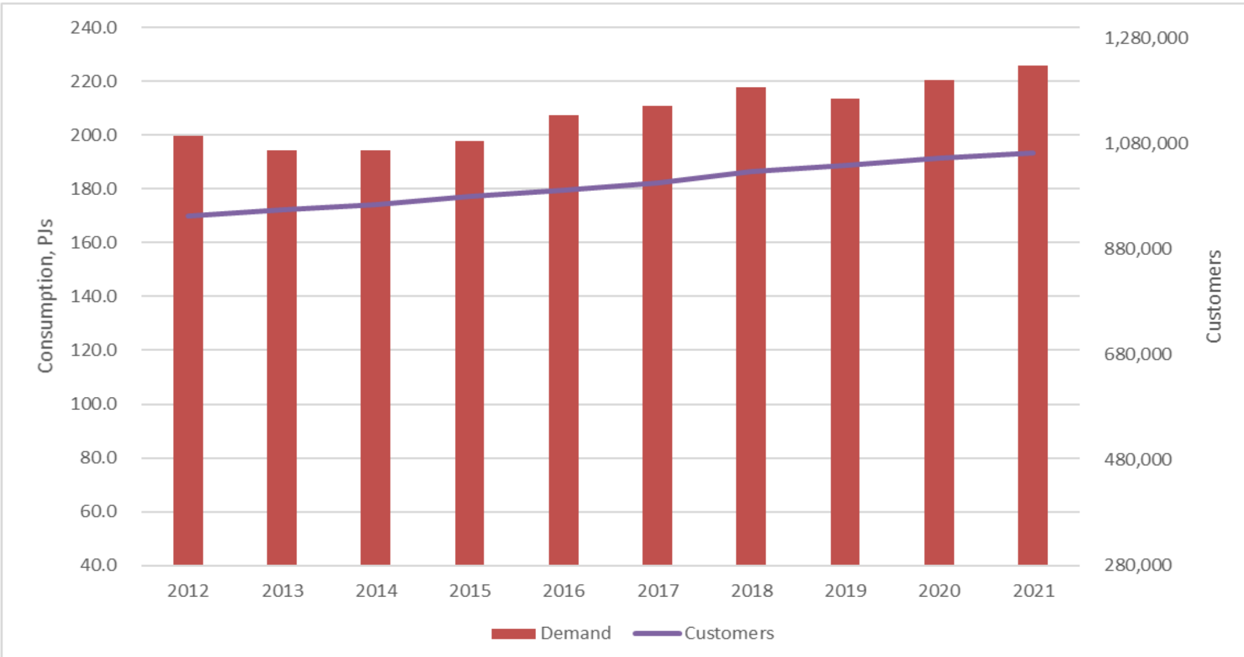
7.6 *USE PER CUSTOMER IMPACT SIMILAR TO 2015*

UPC is a function of two variables: number of accounts and consumption data for each individual rate schedule. In this section, the aggregate trends in UPC variables and changes in UPCs for residential, commercial and industrial sectors are analyzed. Based on the analysis of UPC historical trends, changes in UPC presents a similar risk as presented for FEI in the 2016 Proceeding.

UPC Variables at an Aggregate Level

Figure A7-8 compares the trend in total number of accounts and total throughput. Between 2012 and 2021 the compound annual growth rate (CAGR) for total number of accounts and total throughput is calculated at 1.33 percent and 1.35 percent respectively. Further, since 2015, the addition of new LCT and industrial accounts has resulted in CAGR for total throughput outpacing the CAGR for number of accounts at 2.23 percent and 1.36 percent respectively. This change is in line with FEI's observation in Section 2.3, which indicates that more economically sensitive industrial and LCT sectors, which have higher UPCs, are slowly gaining a larger share of FEI's load and revenue profile.

Figure A7-8: FEI's Total Throughput and Total Number of Accounts

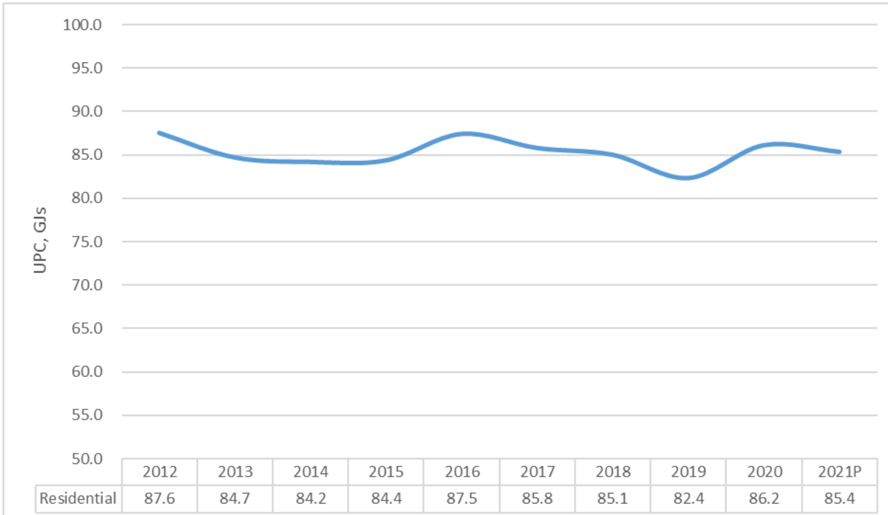


In the following sections FEI's residential, commercial and industrial UPCs are discussed at a more granular level.

Residential UPC

As shown in Figure A7-9, during the last ten years FEI's residential annual UPC has fluctuated between a low of 82.4 GJs, in 2019 and a high of 87.6 GJs in 2012. The increase in 2020-2021 period may be partly related to COVID-19 pandemic effects as people were ordered to quarantine and/or work from home and a spent longer amount of time inside their homes, leading to higher residential consumption. Excluding 2020-2021, the residential UPC trendline would show a downward trajectory since 2016, while including the last two years indicates an almost flat UPC line around 85 GJs.

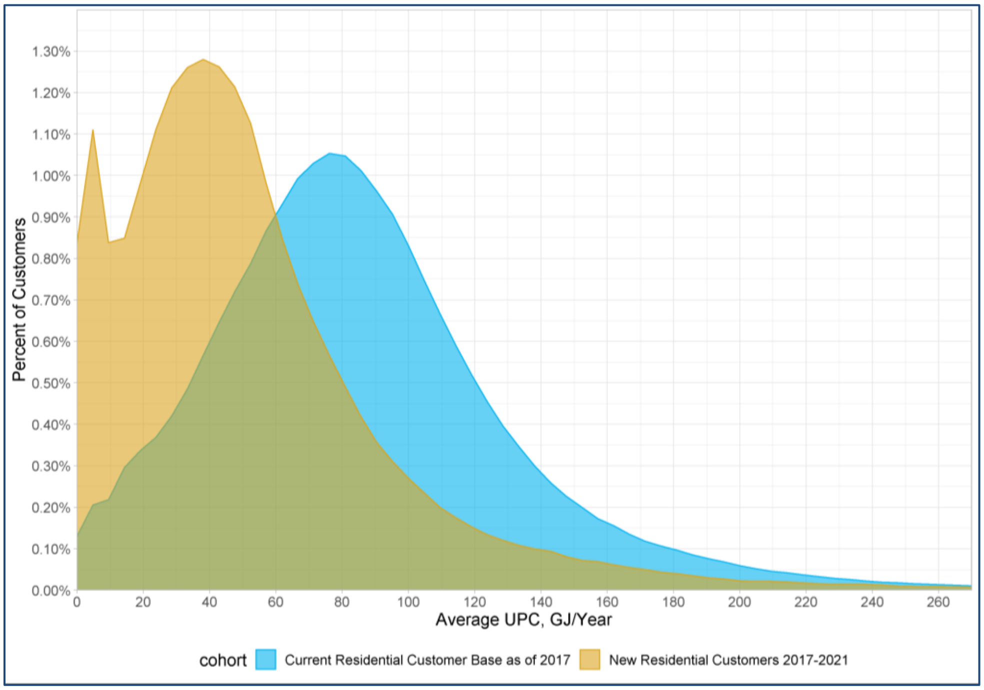
Figure A7-9: FEI's Historical Residential Normalized UPC



FEI's analysis indicates that new customers have significantly lower UPC and, therefore, with the passage of time, and as these customers with lower consumption represent a larger percentage of the overall residential customer base, the residential UPC is expected to decline further. The lower UPC for this group of customers reflects FEI's changing residential customer profile; namely a growing number of MFDs, more efficient gas appliances, more stringent building codes that result in higher efficiency homes as well as the addition of non-heating customers (customers who use gas for cooking or barbecue only).

The frequency distribution curves for FEI's existing and new customers are illustrated in Figure A7-10 below. The median and average normalized consumption for new customers (those added in or after 2017 and that have at least one year of full consumption) is calculated at 46 and 54 GJs per year respectively which is significantly lower than FEI's residential UPC shown in Figure A7-9 above. This trend in UPC for new customer additions in the residential sector will have long-term impacts on the throughput from this sector.

Figure A7-10: FEI's Residential Customer Frequency Distribution[150]

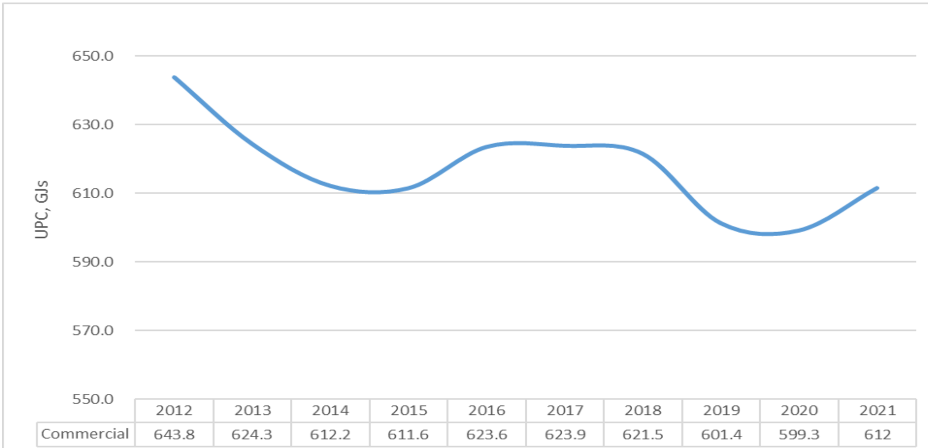


Commercial UPC

FEI's commercial customers (Rate Schedules 2, 3 and 23) consist of customers from a wide variety of business sectors, as well as from condominiums and MFDs (greater than 4 units). Since this is a very diverse group of customers there are many factors affecting their natural gas use that may lead to counter-intuitive changes in the overall average commercial use rate. Figure A7-11 below shows the historical fluctuations in the annual use rate for the commercial rate class.

[150] Due to the billing cycles, the 2021 numbers are not finalized.

Figure A7-11: FEI's Historical Commercial Normalized UPC

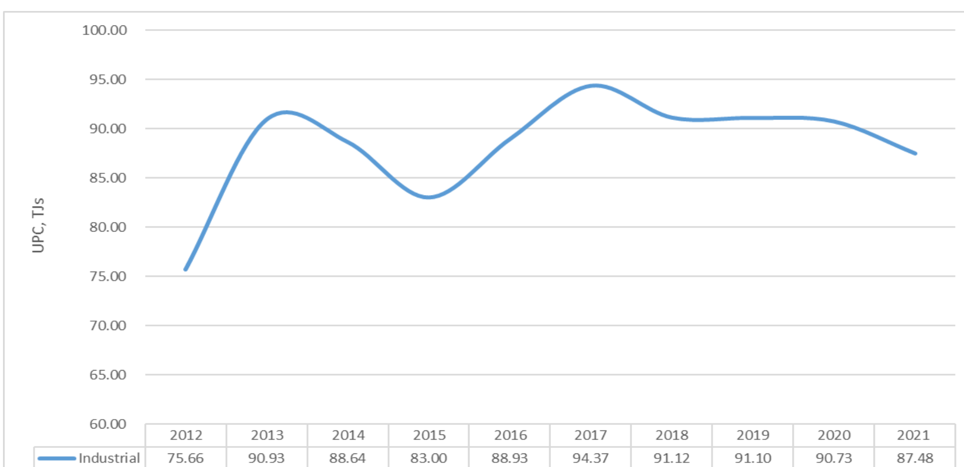


As shown, during the last ten years, FEI's commercial annual use per customer has fluctuated between a low of 599 GJs in 2020 and a high of 644 GJs in 2012. Further, both average and median UPC for commercial customers is calculated at 617 GJs per year. The COVID-19 pandemic has had a severe negative impact in certain sub-sectors of commercial customers but the higher demand in other sub-sectors has lessened the overall negative impact. The projected 2021 UPC indicates that the commercial sector is bouncing back from the 2020 lows.

Industrial UPC

FEI's historical industrial UPC[151] is shown in Figure A7-12.

Figure A7-12: FEI's Historical Industrial UPC



[151] The industrial UPC in this section consists of the following rate schedules: RS 4, 5/25, 6, 7/27, 22/22A/22B, TPT-1, TPT-2 and Byron Creek.

As shown, during the last ten years, FEI's industrial annual use per customer has fluctuated between a low of 75 TJs in 2012 and a high of 94 TJs in 2017. The industrial sector includes a very diverse group of customers with significantly different demand characteristics.

8. ENERGY SUPPLY RISK

Energy supply risk relates to the physical availability of the commodity and the ability to reliably transport it using third party pipelines to FEI's system for delivery to end-use customers. Supply risk for gas utilities, broadly speaking, includes the possibility of supply interruption, which stems from the degree of reliance on a single supply basin, reliance on transportation pipelines, and the availability of regional storage. It also includes the timing and degree of long-term investment in developing and maintaining production, as well as adequate transportation pipeline capacity required to bring production to market.

The analysis of supply risk in this section focuses on: (1) FEI's natural gas supply availability, (2) FEI's access to supply infrastructure in the region, and (3) Renewable Gas supply. When comparing to the 2016 Proceeding:

- Sections 8.1 and 8.2 discuss FEI's natural gas supply availability and access to supply risk that remains largely unchanged from 2015, although FEI's energy supply risk is anticipated to trend upwards if expected demand is added for gas-fired power generation and LNG in BC and surrounding jurisdictions and there continues to be a lack of new pipeline transportation capacity.
- Section 8.3 discusses that Renewable Gas supply has grown in importance to FEI's overall portfolio since 2015, and the increased reliance on this source presents a new and increased supply risk.

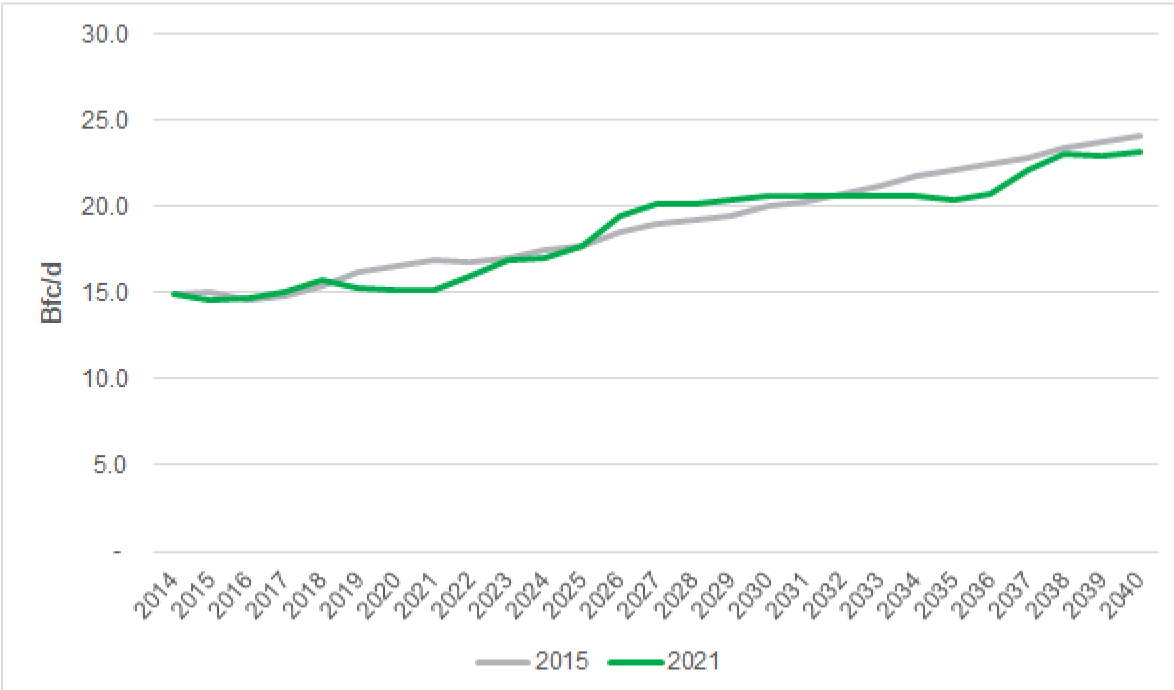
8.1 *AVAILABILITY OF NATURAL GAS SUPPLY – PLENTIFUL SUPPLY, SIMILAR TO 2016 PROCEEDING*

In the oil and gas industry, supply availability is typically separated into upstream activities, referred to as exploration and production (E&P), and midstream activities that include the storage and transportation of energy after its production and commercial sale. FEI continues to source gas supplies from the same market hubs as in 2015, and natural gas remains plentiful.

8.1.1 Upstream Activities Indicate Strong Supply

FEI and other utilities in the U.S. PNW are supplied mainly by natural gas that originates from the WCSB. Figure A8-1 illustrates the previous (2015) and recent (2021) forecast levels of supply from the WCSB.

Figure A8-1: WCSB Production (Actual and Forecast)[152]



As demonstrated in Figure A8-1, the 2021 forecast for natural gas production in the WCSB indicates that production is expected to increase steadily after 2021 before flattening out from 2027 to 2036 and again increasing until the end of the forecast period. It also shows that the recent forecast (2021) is relatively similar to the previous forecast (2015), however, the recent forecast includes greater volatility. This additional volatility is a reflection of future oil market price uncertainty, future demand uncertainty, and regulatory challenges as governments consider and develop policy measures to address GHG emissions.

The forecast increase in production is driven by an expectation of rising natural gas commodity prices and LNG exports. Higher commodity prices and growing access to a new market is expected to support higher drilling levels. The large reserves of economic shale and tight gas located in Northeast BC will play a role in supporting increased WCSB production levels as new markets grow, assuming adequate long distance gas transportation capacity. A need for new markets for production from the WCSB is critical, as access to traditional markets in northeastern North America is increasingly challenged. Traditional eastern markets for WCSB gas have turned to new large scale supply sources located in the northeast US, such as the Marcellus and Utica shale gas basins, for a large share of their supply requirements.

---

[152] Source: ©2021 IHS Markit. All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.

In the future, existing production and increases from new producing areas in the WCSB will also be driven by increased regional demand, including from oil sands development, expansion of gas-fired generation load in Alberta, and increased gas-fired generation in the PNW as existing coal plants retire. LNG exports will develop if production can cost effectively connect to overseas export markets. If these new markets are not connected with transportation capacity, then the natural gas located in large areas of the WCSB, especially the significant resource located in Northeast BC, will remain underdeveloped. Should this occur, it will be more difficult and costly in the future to secure the natural gas FEI requires. The continued development of supply in Northeast BC is necessary to ensure liquidity at the Station 2 market hub located in Northeast BC, where FEI procures the majority of its gas supply requirements.

8.1.2 Limited Midstream (Transportation and Storage) Infrastructure Presents Significant Risk for FEI Accessing Supply

FEI is dependent on limited regional infrastructure to access natural gas supply. The infrastructure in the region remains broadly similar to what it had been in the 2016 Proceeding. In particular, FEI remains dependent on a single pipeline system – the Westcoast T-South system – for most of its natural gas. In the near term, the transportation and storage risk remains similar to the 2016 Proceeding. As new load is added to the existing regional pipeline infrastructure, then supply constraints will increase FEI's throughput risk.

FEI continues to contract with third parties such as Westcoast, TransCanada's NOVA Gas Transmission Ltd. (NGTL) and FoothillsBC, and Northwest Pipeline (NWP) for long distance transportation capacity in order to move supply purchased at different market supply hubs for delivery to its system. This capacity is also used to complete injections and withdrawals from storage facilities, some of which are located a considerable distance from the FEI delivery system. Table A8-1 below provides a summary of FEI's main sources of supply as well as the related supply hubs.

Table A8-1: Summary of FEI's Main Sources of Gas Supply

Pipeline Name	Supply Source	Main Hub	Level of Importance
Westcoast Energy Inc.	NEBC	Station 2	Approximately 80% of FEI's gas is accessed via the Westcoast system. Also used for daily balancing via the Aitken Creek storage facility and for filling market area storage located in Washington and Oregon states.
NGTL / FoothillsBC	Alberta	AECO/ NIT	Approximately 20% of FEI's gas is accessed via the NGTL, FoothillsBC and the Southern Crossing Pipeline system from AECO/NIT. Also provides access to some storage capacity located in Alberta.

Pipeline Name	Supply Source	Main Hub	Level of Importance
Northwest Pipeline	Washington, Oregon storage facilities	Sumas	FEI does not currently contract for Sumas supply but in the future it may provide additional security of supply during winter and peak periods if additional infrastructure is constructed. NWP capacity is used to complete market area storage injections and withdrawals at facilities located in Washington and Oregon states.[153]

As indicated in Table A8-1, FEI remains heavily dependent on gas supply produced in Northeast BC that is transported on the Westcoast systems. A number of communities served by FEI in north-central BC are entirely dependent on supply from the Westcoast T-South system because there is no other infrastructure available for transporting natural gas to these locations. Outages or operational issues, as discussed in Section 8.2, on the Westcoast systems, or in the producing regions, can result in supply shortages on the entire system operated by FEI.

FEI is in competition with other market participants, especially utilities in Alberta and the U.S. PNW, for storage and long distance transportation capacity. Shorter duration market area storage facilities are largely owned by utilities in the U.S. PNW and they have been reserving an increasing share of those resources for their own use as regional transportation capacity has become fully contracted. In addition, east-bound pipeline capacity to the Alberta marketplace from Northeast BC has expanded considerably in the recent past, which provides optionality for producers to bypass the Westcoast systems and the Station 2 marketplace altogether.

There continues to be the supply risk to customers like FEI that rely on the Westcoast T-South system due to regional market changes that have become evident since 2015. The T-South system has been fully contracted for several years in response to demand from power generation in the U.S. PNW. At the same time, T-South capacity has also been contracted by parties anticipating demand from new industrial projects. Until this capacity is required to serve this new industrial demand, this contracted capacity is being used to serve existing industrial demand in the Lower Mainland and U.S. PNW.

A significant volume of gas supply serving industrial customers in the Lower Mainland uses the T-South system to flow on an interruptible basis, which means their gas supply is at risk of being cut in the event there is less uncontracted transportation capacity available. A reduction in available capacity would occur, for example, if any new industrial demand materializes, such as the Woodfibre LNG project. Any major decrease in the future availability of transportation capacity risks leaving these customers without adequate gas supply, or they will need to pay significantly higher commodity prices at Huntingdon before any infrastructure expansions can be completed. Given that these industrial customers have not made a commitment to hold transportation capacity in the past, this may present some challenges for these customers moving forward.

[153] FEI uses NWP capacity to commercially deliver Jackson Prairie and Mist storage gas by displacement.

Some of these customers experienced this problem when they were unable to access sufficient capacity following the Enbridge pipeline rupture and have since returned to the FEI bundled service. This change allows demand from these customers to be served using the FEI contracted transportation capacity which may have a cost impact for FEI to acquire incremental supply for transportation customers that move back to bundled service.

The supply risk to FEI's customers and other PNW utilities increases if new demand is added and there continues to be a lack of new pipeline transportation capacity. The new loads from potential projects are still pending, so in the short term the risks in terms of physical supply to meet the physical demand remain the same. However, if new load is added to the existing regional pipeline infrastructure, then supply constraints will increase FEI's throughput risk. This elevated supply risk will remain until major new infrastructure is constructed, which involves a roughly six to eight year completion timeline. During this period, key activities, such as project identification, negotiation of commercial arrangements, regulatory approval, and completion of construction would need to be completed in an environment that will be increasingly shaped by public policy related to reducing GHG emissions.

8.1.3 Jurisdictional Comparison: BC Market Is Less Liquid and More Infrastructure Constrained

The supply and infrastructure for natural gas in BC is significantly different from jurisdictions elsewhere, such as those in Alberta and Ontario. The key differences relate to greater overall marketplace liquidity in those other jurisdictions, and the larger number of storage facilities and pipeline companies that operate in the Alberta and Ontario regions compared to BC. In addition, the amount of gas that flows in the Alberta/Ontario systems is considerably greater than in BC.

The Alberta marketplace is a very liquid marketplace on a year round basis as it consists of a wide range of suppliers and resellers who are available on a daily basis to buyers. In addition, gas supply is readily available to buyers and sellers on an intraday basis each day in order to manage gas demand within a utility's operating region. The high level of gas flow in the Alberta market using a diverse integrated transportation network, combined with a variety of storage facilities, provides gas supply to customers with no service disruptions in the event of gas plant outages. The close proximity of gas production to market and load centres also reduces the risk of gas supply disruptions for consumers. Although conventional Alberta gas production is declining, the availability of shale gas from BC coupled with significant increases in pipeline connectivity between BC and Alberta is anticipated to maintain the strength and liquidity of the Alberta marketplace.

The natural gas marketplace in Ontario is experiencing change whereby that region has started to benefit from shale gas supply located in close proximity to its operating region from basins such as the Marcellus and Utica. In addition, Ontario has historically benefited from sizable storage and deliverability within close proximity to load and market centres. Ontario's primary trading hub, the Dawn Hub, can access natural gas from the WCSB as well as a number of US supply basins through a variety of pipelines feeding into the Dawn Hub.

Unlike the BC and PNW marketplace, where storage is limited, approximately 265 PJ of underground gas storage owned and operated by utilities also connect into the Dawn Hub, providing substantial operational flexibility for the region. These differences compared with BC are important because they provide the Alberta and Ontario marketplaces with much more secure access to gas supply and are thus lower risk than what BC and the US PNW face.

8.2 *ACCESS TO SUPPLY - ONGOING RISK OF INTERRUPTION ON T-SOUTH*

Access to supply relates to FEI's ability to provide gas supply to its core customers under extreme conditions and emergency situations. As discussed earlier, FEI obtains most of its natural gas via the Westcoast T-South system. This reliance makes a disruption on the T-South system the greatest supply risk FEI faces. Despite the abundance of upstream supply, a major disruption on the T-South system would leave FEI with insufficient supply to meet the daily Lower Mainland load at most times of the year.

The 2018 rupture of Enbridge's Westcoast T-South pipeline presented significant challenges for maintaining service to customers, as it resulted in approximately two days without any flow followed by approximately 14 months of significantly reduced capacity while service was restored. In that case, FEI benefitted from favourable weather conditions that suppressed natural gas consumption in the region, but the outcome would have been much worse had the incident occurred in a period of colder weather. This incident underscored the importance of access to supply and the urgency of making new investments in system resiliency.

Another event occurred in November 2021 that highlighted this same issue, with reduced capacity on Enbridge's Westcoast 30-inch line as a result of its exposure during the recent flooding and mudslides experienced in southern BC due to extreme weather events.

The physical infrastructure in the region has not changed since the 2016 Proceeding and events since then have reinforced the need for FEI to pursue projects that improve resiliency and capacity to mitigate the risk of access to supply. However, this risk to access to supply will not be mitigated until such projects are given approval and completed, which could take six to eight years.

In addition to the access to supply risk associated with reliance on the Westcoast T-South system which can negatively impact gas supply to the entire FEI territory, FEI also faces access to supply risk at more localized levels. For instance, both the Vancouver Island and Whistler service areas are downstream of the Mainland Coastal Transmission System. They are dependent on a pipeline system that traverses challenging terrain. Vancouver Island is supplied with three twinned submarine crossings. While the probability of a total failure of a submarine crossing is small, there is some additional risk associated with the difficulty of repairing a submarine crossing to maintain uninterrupted service once the gas supply that is held in the Mt. Hayes LNG facility has been depleted. Whistler is served by the pipeline lateral between Squamish and Whistler, which faces single point of failure risk. Whistler also does not have any on-system storage facilities that can be used to maintain service in emergency situations. While these risks have been discussed and considered in previous cost of capital applications, the Enbridge Westcoast T-south incident has increased the perceived risk of potential ruptures and future supply disruptions and is a powerful reminder of the significant potential impact that such an incident can have on customers and the utility business.

Without additional investment in resiliency, future supply disruptions that may occur could have significant consequences in terms of cost to customers and socio-economic impacts to society more broadly. This could be exacerbated further if additional load growth materializes over the decade, such as major industrial projects, such as the Woodfibre LNG project. Overall, the risk of access to supply remains similar to the 2016 Proceeding; however, the recent events in the region have highlighted the potential and significant impacts of the risk.

8.3 *INCREASED RELIANCE ON RENEWABLE GAS SUPPLY PRESENTS A NEW RISK*

Renewable Gas has become an increasingly more important component of FEI's supply portfolio, and gives rise to different supply risk considerations. Compared to FEI's natural gas supply, there is greater risk associated with procuring Renewable Gas. While FEI has developed and implemented strategies to mitigate Renewable Gas supply growth risk, the increase in the percentage of FEI's gas supply portfolio composed of Renewable Gas introduces new energy supply risk, especially when FEI brings on future forms of Renewable Gas. Risks include lower than expected supply volume, competition from other purchasers, and gas system readiness. In addition to these physical supply risk factors, there is also policy risk that poses increased business risk for the growth of FEI's Renewable Gas supply.

8.3.1 Increased Reliance on Renewable Gas Supply

The number of operating facilities supplying FEI with Renewable Gas in the form of renewable natural gas (RNG) has increased from one in 2011 to ten in 2021, and FEI has increased annual purchases of RNG each year over this time period. FEI is currently receiving RNG from ten operating Renewable Gas plants located both within and outside of BC. By the end of 2022, FEI expects to see a total of seventeen facilities supplying RNG.

Figure A8-2 below depicts the annual RNG supply volumes that FEI has received from its suppliers over the past ten years and forecasts for 2021 and 2022. The year-over-year growth in supply demonstrates continued performance improvement.

Figure A8-2: Total RNG Supply History and Short Term Forecast

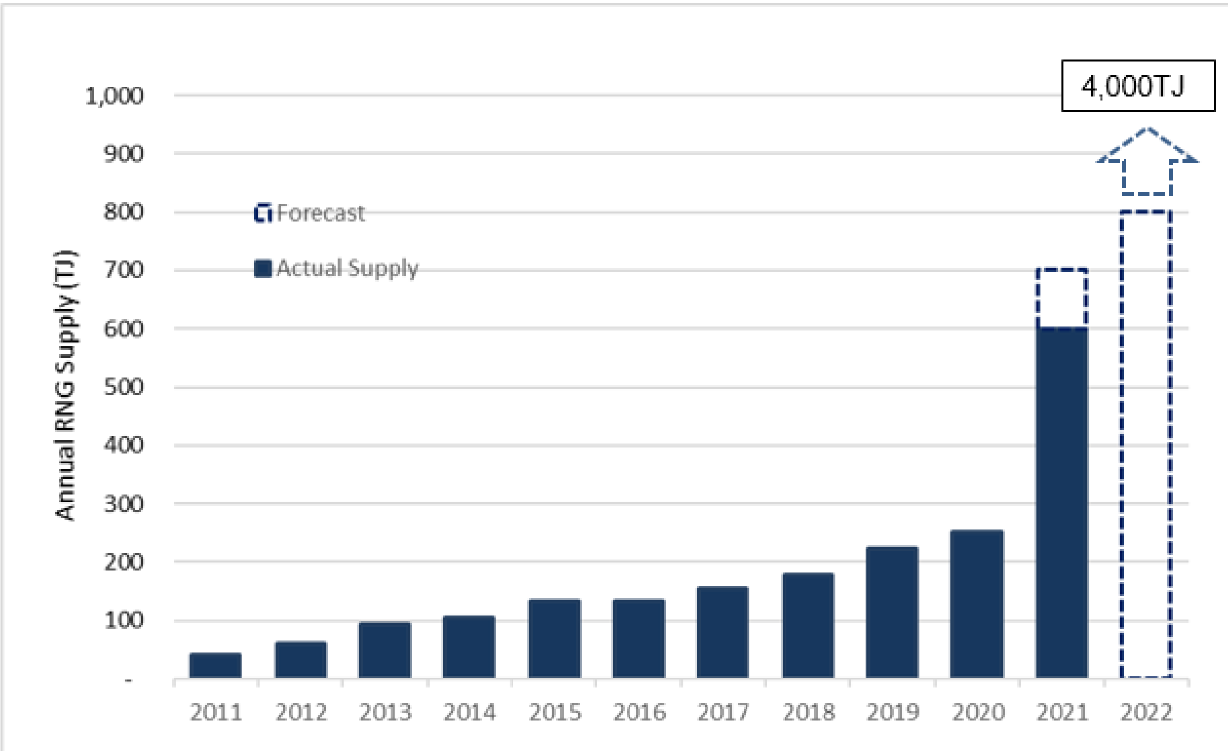
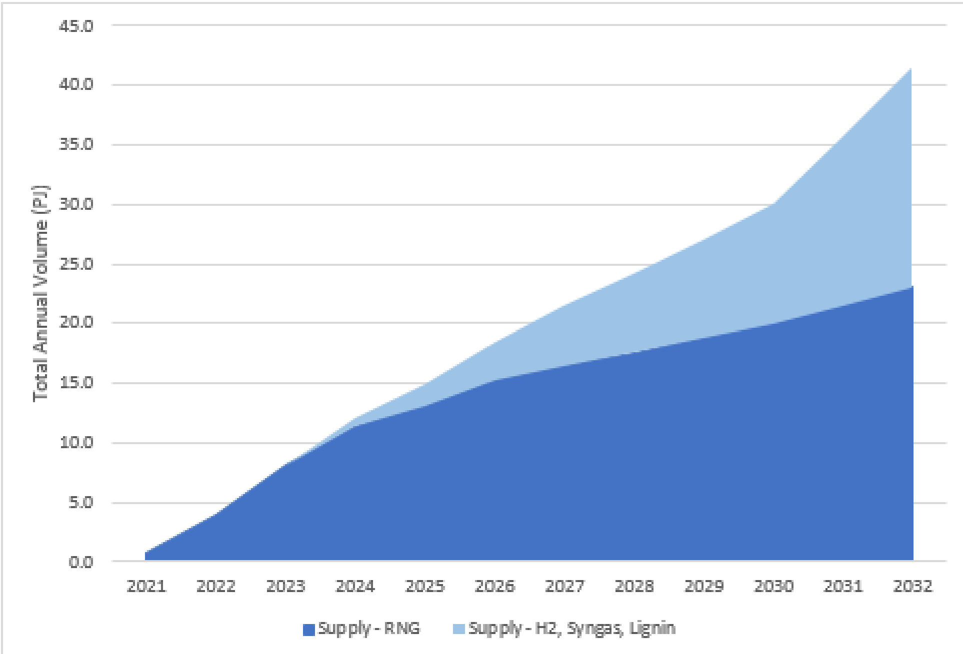


Figure A8-3 below shows FEI's 10-year Renewable Gas forecast. The forecast until 2026 is based primarily on existing and prospective supply agreements. During this period, FEI also expects to begin pilot and pre-commercial stage projects using alternate forms of Renewable Gas; however, these volumes are expected to be relatively low initially. Commencing in 2025, FEI expects to increase supply from alternate forms of Renewable Gas, such as hydrogen and synthesis gas. From 2027 and onwards, the forecast incorporates FEI's expectation of further growth in the use of hydrogen, synthesis gas and lignin.

Figure A8-3: 10-Year Renewable Gas Supply Forecast



Over the 10-year period shown in Figure A8-3, FEI's Renewable Gas portfolio is forecasted to grow from approximately 0.7 PJs in 2021 to 41 PJs in 2032.

8.3.2 Risk of Lower than Expected Renewable Gas Supply Volume

FEI faces supply risk where volumes from suppliers are lower than expected. FEI's experience is that new RNG supply projects typically take time to ramp up their production and may not operate at their contracted maximum volume. Operating projects may experience lower than expected performance due to operational risks similar to a gas pipeline, as described in Section 9, as well as the following, which are unique to RNG facilities:

- **Equipment Failures:** RNG facilities are a relatively new energy form and, as such, the equipment used to create RNG can fail more often than conventional technologies.
- **Feedstock Supply Issues:** Some RNG production facilities (e.g., farm facilities) can have difficulty securing manure or green waste supplies, reducing RNG output.
- **Supplier Experience:** The RNG industry is also at a nascent stage in development, often with small developers/suppliers and new technologies, which creates additional risk relating to the inability for counterparties to execute on project developments and fulfil contractual obligations.

While FEI has a diverse mixture of supply projects that use different feedstocks and technologies and are located in geographically separate areas, this energy supply source introduces new energy supply risk factors.

8.3.3 FEI Must Compete for Renewable Gas Volumes

A second supply risk is competition from other purchasers of Renewable Gas. While FEI has been a "first mover" in the Renewable Gas market, and has an established regulatory path with known guidelines for supply agreements, particularly with respect to RNG, an increasing number of entities in other jurisdictions, including Énergir in Quebec, are now seeking Renewable Gas supply. Further, the market for Renewable Gas is maturing and competition for supply is increasing. Additionally, in certain US jurisdictions, the price of Renewable Gas is considerably higher than FEI's current contracts, causing suppliers to look to other markets. Over time, more and more market actors will develop the expertise and proven pathways to purchase Renewable Gas. Renewable Gas supply introduces a new energy supply risk for FEI, which is challenging to manage given the increased pressure from climate policy to replace natural gas molecules with Renewable Gas.

8.3.4 The Gas System Must Be Ready to Receive and Integrate Renewable Gas

There are technical and regulatory barriers to integrating alternate forms of Renewable Gas, such as hydrogen, into the gas system which presents FEI with a new form of energy supply risk. These barriers could delay the use of hydrogen, synthesis gas and lignin to provide FEI's customers with low carbon energy. As volumes of newer forms of Renewable Gas increase, a further system-wide feasibility analysis is required to ensure that the gas system can manage these increasing volumes:

- Examining system extensions and upgrades required to connect producers of Renewable Gas where these producers are located in regions of BC where capacity to inject is limited or without gas pipeline infrastructure connecting to the existing gas system;
- Assessing the blending of hydrogen into the natural gas supply, including a technical readiness evaluation; and
- Analyzing how the natural gas system can accommodate distributed gas production, at a scale large enough to meet FEI's Renewable Gas objectives, as more geographically diverse supply is brought on the system.

FEI must also engage regulators, such as NRCan Codes and Standards, to modify and develop safety and technical standards and set longer-term objectives to transition the regional natural gas network to adopt hydrogen, synthesis gas and lignin. This includes hydrogen-ready infrastructure initiatives, such as the certification of new appliances and equipment and the design of hydrogen-ready compatible natural gas infrastructure.

The outcome of these analyses and FEI's ability to evolve its operational practices to allow more energy supply mix flexibility within its existing system is uncertain, increasing FEI's business risk.

8.3.5 Governments Must Be Prepared to Accept Non-local Renewable Gas Supply

FEI's assets can support achievement of government GHG emission targets. In particular, the extensive coverage and interconnectivity of the natural gas system makes the system a critical vehicle to deliver low carbon energy to British Columbians. Further, as a "drop-in fuel", Renewable Gas is an energy source that meets the objectives of all three levels of government (as discussed in Section 4) and leads to relatively quick, easy and cost effective GHG reduction solutions. FEI's supply forecast includes both locally sourced and non-locally sourced Renewable Gas supply. There remains uncertainty about future government policy that may impact the recognition of future sources of FEI's Renewable Gas supply contributing to FEI's GHG emissions reductions requirements. This could create a scenario where FEI has long-term contracts for supply that might not be usable in British Columbia. This could result in extra future costs associated with adjusting or potentially cancelling contracts.

9. OPERATING RISK

Operating risk includes the physical risks to the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography, human error, and weather. FEI operates in a complex operating environment, that has continued to increase in complexity since the 2016 Proceeding, due to factors such as: heightened awareness of safety, environmental stewardship, resiliency and reliability; increasing public scrutiny of energy project development; local governments and Indigenous governments seeking to influence energy infrastructure while also maximizing benefits for their communities; and evolving customer expectations. FEI assesses that, compared to the 2016 Proceeding, the operating risk facing the facilities in the FEI service area has increased. Specifically:

- Sections 9.1 and 9.2 discuss that infrastructure and time dependent threats and third party damages remain business risks of FEI which are largely unchanged from 2015.
- Sections 9.3, 9.4 and 9.5 explain how negative sentiments towards the fossil-fuel industry, municipal challenges to FEI's right to construct and operate and cybersecurity are newly identified operating risk categories since the 2016 Proceeding, and have become significant considerations for FEI, increasing operating risk.
- Section 9.6 discusses how unexpected events such as the COVID-19 pandemic and Enbridge's T-South pipeline rupture in 2018, as well as recent extreme weather-related events in the province, such as record wildfire activity, flooding and mudslides, are expected to continue to occur and become more widespread, increasing FEI's operating risk.

9.1 *AGING INFRASTRUCTURE AND TIME DEPENDENT THREATS PRESENT A RISK*

Aging assets and time dependent threats increase the risk of asset failure resulting from corrosion and cracking, known to exist on some FEI assets. FEI's risk of aging infrastructure and time dependent asset failure remains similar to that of the 2016 Proceeding.

Similar to 2015, nearly a quarter of distribution mains and approximately a third of FEI's intermediate and transmission pressure pipelines have been in service for more than 45 years. FEI anticipates, given the current understanding of the expected service life of assets over the next forty years, 79 percent of steel mains and 54 percent of transmission system pipelines will be past their expected service life of approximately 65 years.

The operating risk associated with aging infrastructure relates to the ability of FEI and its service providers to identify and respond to long-term utility infrastructure replacement programs and the activities required to operate and maintain an aging system. There are many variables impacting the useful life of underground pipe including pipe material, pipe coating, soil conditions, external interference, corrosion, etc. FEI has several programs in place to monitor, inspect and assess pipe condition, and as a result of these assessments, has developed longer term capital programs to replace sections of pipe that are reaching the end of their service life and contributing to increased operating risk. The primary challenges in terms of executing on infrastructure replacement plans are in obtaining permits and approvals (see Section 9.4), and in obtaining project resources to perform the work. Challenges with receiving permits from local governments, and permit restrictions and requirements are delaying critical infrastructure replacement and maintenance projects. As competition for project resources (project managers and engineers, planners and experienced field resources as well as financial professionals) hardens, it is becoming increasingly difficult for FEI to attract and retain these resources.

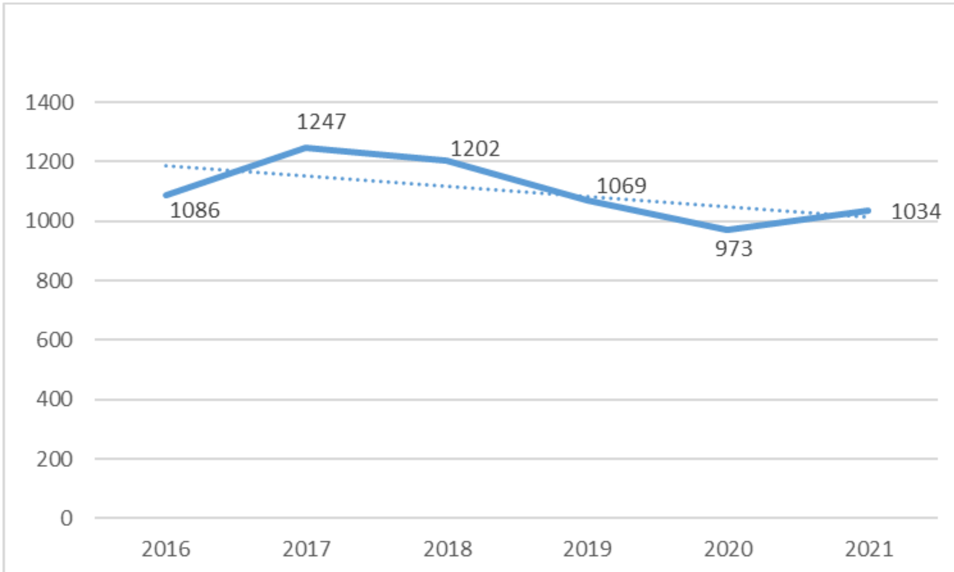
FEI's infrastructure will require investment over its lifecycle to ensure ongoing safety, reliability, integrity, resiliency, and environmentally responsible performance. Both corrosion and cracking are considered time-dependent integrity threats, meaning that their potential to impact pipeline infrastructure may increase over time if not appropriately mitigated. Corrosion and cracking are known to exist on some FEI assets, and until such time as the locations and characteristics can be specifically identified and mitigated, there is a continued risk of asset failure that increases with time. The risk profile will not start to level off and decrease until projects, such as the Transmission Integrity Management Capabilities Program, are implemented. Such projects will enable FEI to more broadly identify time-dependent integrity threats that may cause catastrophic and unexpected failures.

9.2 *THIRD PARTY DAMAGES PRESENT A RISK*

Third party damage is a recognized hazard to gas assets and refers to third parties either accidentally or deliberately damaging gas assets below ground or above ground. Damage is usually caused by a contractor, municipality or homeowner excavating in the vicinity of gas assets, following unsafe excavation practices and damaging the gas main, service line, or meter, which can result in the loss of gas, GHG emissions, service interruptions and significant repair costs. This type of damage can also result from vandalism. Third party damages are a significant risk, in part due to the typical proximity of the damager (i.e., the person digging) to the gas asset in the event that there is a breach of containment. Depending on factors such as pipe material, pipeline internal pressure, and the characteristics of the pipe damage itself, this hazard has the potential to result in a leak or rupture failure. A leak or rupture subsequently has the potential to ignite and can be a risk to incident responders and the public. As such, industry and regulators implement and often collaborate on damage prevention measures. FEI's operational activities such as participation in the BC One Call process, installing pipeline markers along rights-of-way, communicating public awareness messages and the recent implementation of marker tape above underground gas assets mitigate the potential for damage.

After peaking in 2017, the number of incidents of third party damage has been on a slight downward trend. Although third party damages are trending down, FEI still experienced 1034 incidents in 2021 which is close to the number of third party damages experienced in 2016. The downward trend has leveled off in recent years and FEI is needing to continually improve the damage prevention program to maintain the current risk level. Figure A9-1 shows the third party damage downward trend and leveling off since the 2016 Proceeding.

Figure A9-1: Third Party Damage Trend from 2016 to 2021



9.3 *NEGATIVE ATTITUDES TOWARDS FOSSIL-FUEL INDUSTRY CREATES NEW OPERATIONAL CHALLENGES*

FEI has added this new risk factor since the 2016 Proceeding in recognition of the growing impacts on FEI's business of negative attitudes towards the fossil fuel industry. Political and media campaigns against the fossil fuel industry in Canada and BC build hostility towards fossil fuel infrastructure investments and projects. The negative public sentiment towards natural gas pipelines can hinder FEI's ability to recruit skilled workers, complete already approved projects on time and budget, meet environmental and safety requirements or obtain necessary approvals and operating permits. With the province's updated Roadmap, FEI believes that the concerns around natural gas utility activities has increased.

Recruiting top talent to a carbon-based industry is more challenging as the industry is perceived by some to not have a future, and candidates may not want to work for an employer in an industry with a negative stigma. It is also more challenging to hire experienced contractors and trades as there are fewer people entering the industry. Critical work takes longer to complete, increasing the risk of system failure, non-compliance to regulations, and not meeting customer expectations.

Protests and environmental activism are becoming more frequent (see Section 5.4). FEI is seeing increased resistance to new projects which is leading to higher risks to execute projects on time at the lowest reasonable cost. There have been instances of vandalism in respect of fossil fuel assets in North America. The impacts of the environmental movement are far reaching. Protests and environmental activism threaten safe and reliable energy delivery to customers.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including discharge of air emissions, spills into the environment, waste management, use of hazardous substances, interactions with sensitive species and their habitat, and working in and around water. FEI is experiencing increasingly strict environmental and safety laws, regulations and enforcement policies since 2015.

9.4 *OPERATING CHALLENGES ARE INCREASING IN MUNICIPALITIES*

Municipalities are imposing requirements on FEI that were not previously experienced as frequently or at the level FEI experiences today. Some municipalities are even challenging FEI's ability to operate in the municipalities.

9.4.1 Increased Municipal Expectations and Requirements

In order to serve customers in municipalities, FEI must operate in municipal public lands. FEI has agreements with over 100 municipalities in the province setting out agreed terms and conditions of FEI's use of municipal public spaces. However, FEI does not have such agreements with every municipality in its service territory, and the agreements all leave some issues to be addressed and can preserve some discretion for municipalities.

The additional municipal requirements and associated costs arise in the context of both FEI's ongoing operating and maintenance activities and its larger construction projects. FEI's approach is to manage these additional requirements by negotiating an acceptable compromise with the municipality, taking into account FEI's rights and obligations under applicable statutes[154] and under the operating agreement (if applicable) between the municipality and FEI.

In some cases, these increasing requirements and challenges give rise to disagreements with some municipalities requiring resources and time to resolve. Resolution may involve higher costs to FEI in order to avoid schedule delay.

In the context of ongoing operating and maintenance activities, additional requirements include matters relating to surface restoration, public notification, additional permitting, and security deposits. Typically, FEI and the municipality are able to reach a compromise, which is consistent with FEI's rights and obligations. In some cases, resolution may involve additional costs for FEI in terms of process changes and additional work in order to complete the required operation and maintenance activities.

Particularly in the context of larger construction projects, municipal requirements and restrictions may create project and schedule uncertainty for FEI. These requirements include matters such as route selection, permitting requirements, and public notification requirements. FEI seeks to manage these risks through advanced planning and collaboration with the municipality. This may involve FEI incurring some additional costs, such as a community contribution, or doing some

[154] UCA and the *Gas Utility Act*, R.S.B.C. 1996, c 170.

additional work typically related to project impacts. In exchange, the municipality may agree to concessions such as: (i) timelines for activities such as permit review and issuance, including any approval required under an operating agreement and applicable land use permits, (ii) variances to applicable bylaws (such as noise, times of work); and (iii) designated municipal staff to support FEI's project. In some cases, FEI enters into a community benefit agreement with a municipality, regional district, and/or community association often at the recommendation of the municipality. Such community benefit agreements may include direct compensation to the municipality and/or contributions towards recreational, social, or cultural assets for community use, or improvements to municipal infrastructure. These community benefit agreements serve to protect and enhance FEI's reputation in the community and leave the community with a benefit that endures after the completion of the construction work.

FEI has long-standing operating agreements in the Lower Mainland region, where the bulk of FEI's business is located. Some Lower Mainland municipalities are raising the prospect of renegotiating these operating agreements. Municipalities are interested in operating fees (no fees are currently payable under these agreements), which are added to the customer bills, and adding more protocols and procedures around FEI's use of municipal public spaces. Renegotiations with the City of Surrey took place over several years and required the intervention of the BCUC and a lengthy process to resolve. In recent months, there has been a dispute with the City of Richmond (which does not have an operating agreement with FEI) about altering FEI's infrastructure at the City's request that also had to be resolved by the BCUC and is currently under reconsideration.

9.4.2 Municipal Challenges to FEI's Right to Construct and Operate

Municipalities have begun challenging FEI's right to construct and operate within some municipal public spaces in ways that had never previously occurred. Municipalities are endeavouring to impose additional requirements and restrictions, some of which seek to limit or restrict FEI's rights to use public spaces. Disagreements with municipalities about FEI's rights and obligations can cause work delays and impose additional costs on FEI. Where FEI and the municipality are unable to reach a compromise, disputes require resolution through lengthy and costly regulatory and legal processes. The recent three-year dispute and litigation with the City of Coquitlam over requirements for paving and the use of public lands for an abandoned gas line is an example of how involved these disputes can become.[155] These municipal expectations, requirements and disputes result in increased costs to FEI, and contribute to increased operating risk as well.

9.5 *CYBERSECURITY HAS BECOME A SIGNIFICANT RISK CONSIDERATION*

Cybersecurity risk is a newly identified risk category in FEI's operational risk section when compared to the 2016 Proceeding. Its inclusion in the evidence reflects the fact that risk of cyber-attacks on energy infrastructure has increased. The recent ransomware attack on Colonial

[155] BCUC Order G-158-18 (Phase One), BCUC Order G-80-19 (Phase 2), BCUC Order G-75-20 (Reconsideration), *Coquitlam (City) v. British Columbia Utilities Commission*, 2021 BCCA 336.

Pipeline, a major pipeline in the U.S., and its impact on energy security in multiple U.S. states highlight the severity and seriousness of this risk.

Operational risk resulting from cyber-attacks has increased since 2015 for FEI as bad actors and their tools become more sophisticated, and operations has increased their reliance on technological systems and controls. Loss of control of any of these systems or ability to manage critical work increases operational risk. Control systems include sophisticated components that rely on software and network infrastructure to control the gas network and report system status in real time. Sophisticated office and mobile systems provide the ability to manage work and provide office and field employees with critical information to complete work and respond to emergencies such as third-party damages.

The increasing reliance on systems and infrastructure that is susceptible to cybersecurity threats increases corresponding operational risk.

9.6 *FREQUENCY AND IMPACT OF UNEXPECTED EVENTS HAS INCREASED*

FEI has a large radial system that crosses rivers, watersheds, seismic zones, and mountainous and forested terrain. Natural events contributing to operating risk in BC include floods, washouts, forest fires, land slippage, and earthquakes. While the timing of these events is somewhat unpredictable and cyclical in nature, FEI has systems in place where possible to mitigate the impacts of these natural forces. FEI assesses the magnitude of unexpected events as having increased since 2015, given the apparent increasing prevalence of disruptive natural events.

The following are several examples of natural events in recent years that have affected infrastructure:

- Natural events such as the Fort McMurray wildfire in 2016 are becoming more regular. To help secure the safety of the community, the local natural gas utility shut down the natural gas system. Once the immediate danger had passed, it took the utility nearly two weeks to prepare the system for the re-introduction of natural gas, and an additional two weeks to relight approximately 20,000 customers involving a reported 150 field operations personnel.
- The recent flooding in Fraser Valley, Merritt, Princeton and Abbotsford, while less severe than the impact of the Fort McMurray wildfire, resulted in 4,200 customers potentially impacted and the loss of natural gas service to 1,700 customers.
- The recent flooding of an adjacent river exposed a portion of Westcoast's 30-inch line such that a section was fully uncovered in the overflowing river.

Reduced supply of natural gas can result in FEI not being able to meet the needs of its customers or avoid service disruptions. Communities at the extremities of the radial system are at the greatest risk of losing natural gas service. In cases where loss of service is imminent, a controlled shedding of load to avoid widespread system failure is essential. The controlled load shedding and orderly relight process required to ensure service can be safely restored means that affected customers could be without service for an extended period. Projects such as Advanced Metering Infrastructure and the Tilbury LNG Storage Expansion can reduce the risks of extended service disruptions to customers.

The COVID-19 pandemic is another example of an unknown and unexpected event. Operating the natural gas system through a pandemic can be challenging. The system needs to be operated and maintained appropriately to ensure safe reliable service to customers. Routine activities such as operating, maintaining, and serving customers is even more critical as the system is relied on to deliver the energy needs of the province. Extra measures such as Personal Protective Equipment (PPE), self-service relight technology, and redundant controls are required to help ensure employees and customers remain safe. Controlling pandemic exposure and outbreaks is essential to ensure sufficient skilled workers remain available for critical operations.

In many cases, proactive emergency planning and emergency response exercises can reduce the impacts of these events. FEI has emergency plans and completes regular emergency response exercises to mitigate controllable risks. Given that the location and extent of these types of unexpected events remains unpredictable, they increase FEI's operating risk.

10. REGULATORY RISK

The degree to which FEI, as a regulated public utility, is dependent on regulators for timely and fair approvals to earn its return on and of capital results is what FEI refers to in this section as regulatory risk. In the 2013 Generic Cost of Capital Stage 1 Decision, the BCUC acknowledged that "the BC regulatory framework has a significant influence on FEI's business and that individual decisions can have significant implications for FEI."[156] A stable and supportive regulatory environment is also one of the main factors that is considered by credit rating agencies.

FEI has assessed its overall regulatory risk as higher than what was assessed in the 2016 Proceeding, with certain risk factors increasing and others being similar. The main points discussed in the following sections are:

- Section 10.1 discusses how there is an increased level of regulatory uncertainty, driven both by the BCUC's decision to review the financing of deferral accounts, increased uncertainty of approval for FEI's initiatives supporting the future of the gas system, as well as uncertainty around pre-project approval funding. There is an increased potential for regulatory lag in both BCUC and other regulatory processes, associated with, for instance, increased requirements for environmental reviews, and consultation and engagement.
- Section 10.2 explains how, although regulatory requirements are getting more complex and expansive, FEI has nonetheless characterized its risk exposure associated with administrative penalties under the UCA and other regulatory frameworks applicable to FEI as similar to the 2016 Proceeding.

10.1 *INCREASED RISK RELATED TO UNCERTAINTY AND LAG IN REGULATORY APPROVAL*

FEI is subject to a number of regulatory regimes, with BCUC regulation being notable. As a regulated public utility, FEI can only construct significant utility assets with a CPCN approval. It can only charge rates that have been approved by the BCUC. The BCUC sets the allowed return on equity and capital structure of the utility, and assesses depreciation rates that permit recovery of invested capital. The BCUC, as a statutory entity, acts pursuant to its power under the UCA but, within that framework, has significant discretion in the exercise of those powers. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty. Regulatory oversight gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that do not provide FEI with an opportunity to earn its fair return on and of capital, or that necessary investments are not approved.

[156] 2013 GCOC Stage 1 Decision, p. 40.

10.1.1 Overview of Current Regulatory Framework

There has been no fundamental change in FEI's regulatory framework under the UCA since the 2016 Proceeding, although there has been some increase in the level of costs that are subject to earnings sharing rather than flow-through treatment. The BCUC's decision to review the financing of deferral accounts as part of this Proceeding has introduced additional risk.

10.1.1.1 2020-2024 MRP Decision

In June of 2020, BCUC Decision G-165-20 approved FEI's 2020-2014 Multi-year Rate Plan (MRP) for a five-year term (2020 through 2024). Compared to the 2014-2019 PBR plan, certain changes, such as a reduction in the amount of costs subject to the flow-through mechanism (discussed in the following section) and elimination of the capital dead-band mechanism for the growth capital formula, have the effect of increasing FEI's risk, while other changes, such as the elimination of the multiplier factor for the growth capital formula and the decrease in the materiality threshold for the Z-Factor mechanism, have the effect of reducing FEI's risk. Experience to date has shown that the lack of a dead-band mechanism for growth capital is a realized risk, since FEI's actual growth capital costs have been above the formula-allowed amount; a situation that will worsen during the remainder of the MRP term if FEI's input costs continue to increase higher than the inflation factor. Overall, FEI believes that the risks associated with the MRP are similar to the risks identified for the PBR plan in the 2016 Proceeding.

10.1.1.2 FEI's Deferral Accounts Now Exclude Some Costs that Were Previously Flow-Through

Deferral accounting can help to reduce the rate impact and rate volatility for customers. The BCUC determined in the 2009 Cost of Capital Decision that "…the effect of deferral accounts in reducing the risk of [FEI] as reducing the short-term, and not the long-term, business risk of [FEI]...".[157] In other words, deferral accounts can delay the short term rate impact of risk events but cannot eliminate risks.

The majority of FEI's deferral accounts have been put in place to ensure forecast variances do not result in costs being inappropriately borne by customers or the company. In the 2014 PBR Decision, the BCUC directed FEI to discontinue the use of a number of deferral accounts;[158] however, the discontinuance did not, in and of itself, materially change FEI's short-term risk profile since the BCUC also directed FEI to true-up those costs each year through a flow-through mechanism[159] for the term of the PBR Plan. The rest of FEI's key deferral accounts remained unchanged.

[157] 2009 Cost of Capital Decision, p. 19.

[158] Tax variance deferral account, the property tax variance deferral account, the insurance expense variance deferral account and the interest expense variance deferral account.

[159] The flow-through deferral account also includes items such as customer variances for residential and commercial customers as well as the industrial margin variance.

In the 2020-2024 MRP Decision, the BCUC approved a similar flow-through mechanism; however, that mechanism was modified to exclude certain controllable variances related to O&M, other revenue, depreciation, interest and taxes[160]. Instead, any variances between actual and forecasted revenues and costs for those items would now be subject to 50/50 sharing with customers.

Table A-10.1 summarizes the general categories of FEI's deferral accounts.

Table A10-1: Deferral Accounts

Deferral Account Category	General Purpose & Description
Margin Related	• Decreasing the volatility in rates caused by such factors as fluctuations in commodity prices and the significant impacts of weather on use rates • Deferring the cost of gas and delivery margin impacts arising from un-forecast variations in these types of factors and recovering them from/refunding them to customers over a longer period of time to reduce rate volatility Examples: Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (MCRA) and Revenue Stabilization Adjustment Mechanism (RSAM)
Energy Policy	• Capturing costs associated with energy policies that focus on energy efficiency, conservation and the environment • Deferring and amortizing these costs matches the costs of the programs with a reasonable period of time over which the benefits are expected to be realized by customers Examples: Demand-Side Management (DSM), GGRR Incentives
Non-Controllable Items	• Items which are either outside of the company's control or where the company has limited ability to influence the costs • Deferring the variances from the forecast level of costs for these activities reduces the exposure for both the utility and customers due to significant variances in these amounts, and serves to avoid windfall gains or losses to the company or to customers Examples: Flow-through deferral account, Pension and OPEB Variances, BCUC Levies Variance
Costs of BCUC Applications	• Captures costs required to support regulatory applications, such as intervener and participant funding costs, BCUC costs, costs for expert witnesses and consultants, costs related to independent validation of study results, legal fees, required public notifications, and miscellaneous other costs Example: 2020-2024 MRP Application Costs deferral account
Other	• Various accounts that provide benefits to customers and the company, often for items that are non-recurring in nature Examples: COVID-19 Customer Recovery Fund, MRP Earnings Sharing Account, Clean Growth Innovation Fund, Whistler Pipeline and Conversion Costs

[160] Order G-165-20, p. 74.

10.1.1.3 The BCUC Is Revisiting Deferral Account Financing Costs

Currently, deferral account financing treatment is reviewed as part of the revenue requirement applications for individual utilities and reflects the utility's specific circumstances. The financing treatment of a number of FEI's accounts has been settled for years. However, pursuant to the Industrial Customers Group's request and by Order G-205-21, dated July 7, 2021, the BCUC Panel determined that the review of deferral account financing costs should be subject to a generic proceeding after the completion of Stage 1 and Stage 2 of this proceeding. In its decision, the BCUC panel acknowledged that "the existence, or lack of, variance and other deferral accounting treatment can affect a utility's business risks which is a consideration for determining the cost of capital for a utility"[161] but also suggested that it may vary from the established case-by-case review approach and consider whether a consistent approach across BC utilities is appropriate and fair.

As recognized by the BCUC Panel, deferral account financing does impact FEI's business risk since the financing has a direct impact on a utility's earnings. Whereas the approval of a deferral account addresses short-term risk by managing the level of costs in rates, usually by smoothing those costs over a period of time, the account does not change the underlying level of cost. This is in contrast to decisions related to the recovery of costs incurred by the utility in financing its deferral accounts, which impacts cost recovery itself. A more generic approach to deferral account financing can lead to approval of unfair and inappropriate financing treatment if a utility's specific circumstances are not fully recognized. The decision to revisit deferral account financing costs itself creates uncertainty for FEI. It can potentially depress FEI's credit metrics, if for instance the deferral accounts that are financed by debt and equity are replaced with deferral accounts that are only allowed to attract a debt return.

10.1.2 Heightened Uncertainty around Regulatory Approvals and Increased Potential for Regulatory Lag

As a general proposition, regulatory uncertainty associated with the unpredictability of future decisions, vague decisions that are open to interpretation by current or future regulatory panels, or unknown future implications of current regulatory decisions will lead to increased regulatory risk.

10.1.2.1 Regulatory Support for Important Initiatives is Uncertain

All BCUC regulatory applications are subject to some level of regulatory uncertainty. Revenue requirement applications, major CPCN applications, rate design applications and certain applications related to important initiatives, such as Renewable Gas programs, that may require reduced reliance on cost of service ratemaking principles, usually involve a heightened level of regulatory uncertainty. In the following section, the regulatory uncertainty risks associated with

[161] Exhibit A-6, Appendix A, p. 3.

FEI's important initiatives are discussed in more detail. The risk in this regard has increased since the 2016 Proceeding.

As explained in Section 4, FEI is facing significant policy challenges from all levels of government that could result in underutilized capacity of the gas system (stranded asset risk). FEI believes there is a path forward that can achieve climate policy objectives while maintaining FEI's crucial role in providing safe, reliable and affordable energy to British Columbians. FEI will need to implement important initiatives to achieve that vision, and those initiatives will require significant regulatory support and flexibility. The current uncertainty around the extent of the BCUC's (and interveners) support for these initiatives represents an increasing risk compared to the 2016 Proceeding.

As an example, low-carbon gas alternatives such as Renewable Gas have a higher cost basis than traditional natural gas, requiring approval of different cost recovery approaches. The current regulatory framework, including customer cost recovery mechanisms, does not directly support higher cost forms of gas. Different rate structures will need to be approved for customers who may not be able to access natural gas due to governments' carbon intensity targets and would therefore require a Renewable Gas blend or 100 percent Renewable Gas.

If the BCUC takes a restrictive interpretation of legislation, applies traditional rate-making principles in a way that impedes development, or emphasizes short-term affordability over resilience and decarbonization goals, this can hinder FEI's ability to implement important initiatives that align its operations with government policy and promote FEI's role in the low-carbon economy.

Further, due to the uncertainty around the future role of natural gas in BC's energy infrastructure, FEI's capital intensive CPCN projects are also facing a higher level of regulatory uncertainty such that the BCUC may be hesitant to approve projects that add to the system capacity and lead to higher rates. This, in turn, will impact FEI's ability to adapt to a low carbon environment.

These positions have been advanced in FEI's recent CPCN projects, including:

- The Tilbury LNG Storage Expansion Project, where FEI received a significant volume of information requests on the need for this project in light of future demand, and where the BCUC has stated that "evidence respecting decarbonisation and future gas demand is relevant to this proceeding";[162]
- The Okanagan Capacity Upgrade Project, where there has been significant debate about whether FEI will have the load requirements to support the project and evidence has been filed by Dr. Chris Joseph on the topic;[163] and

[162] Appendix B to Order G-9-22 page 2 of 4.
[163] See Exhibit C-5-9 in that proceeding.

- Although not anticipated, even the Advanced Metering Infrastructure Project, which is not about demand, capacity or expansion of the gas system, received information requests in this area.[164]

Interveners have also questioned the continuing applicability of FEI's MRP in light of recent climate policy initiatives[165]. FEI expects these topics to be explored in even greater detail in its upcoming Long-term Gas Resource Plan.

10.1.2.2 The Potential for Regulatory Lag Has Increased

The growing complexity of FEI's operating environment can lead to delays (regulatory lag) in system investments, or the delivery of service offerings. Regulatory lag, which can be associated with BCUC or other regulatory processes, can present a risk for FEI's return on and of capital.

One aspect of regulatory lag is the time between BCUC application filings and final approvals. Given the complexity of the regulatory process, there is going to be an inherent delay between the time an application is filed and when the final order related to that application is issued. While the need to conduct regulatory reviews of utility operations is an integral part of being a public utility, the resulting delay does create risk for the utility. Risk arises in part because it can be necessary for the utility to conduct its operations based on interim rates, with no assurance that the interim rate will be confirmed in the final decision, or the risk that the costs incurred and projects contemplated and required to be undertaken will ultimately be approved. In the case of capital approvals, delays or non-approval can create obstacles for FEI completing projects on time and on budget or can impede FEI's ability to proceed with important initiatives, as discussed above.

FEI believes that, compared to the 2016 Proceeding, the risk associated with regulatory lag has experienced a notable increase. FEI has observed increased interest and active participation by Indigenous and environmental groups in regulatory proceedings, such as its CPCN applications for the Okanagan Capacity Upgrade and the Tilbury LNG Storage Expansion projects. Further, some Indigenous groups have suggested there is uncertainty with respect to the BCUC's statutory scope with respect to reconciliation and the duty to consult. These delays not only result in regulatory lag, but they can increase costs as well. An example of this is that FEI is currently developing interim measures to address the delay to approval of its Okanagan Capacity Upgrade project that has resulted from a longer than anticipated regulatory process, to ensure continued supply of gas to its customers in that region.

10.1.2.3 Increasing Complexity and Cost of Projects Has Increased Dollars at Risk

While FEI is experiencing regulatory lag in the BCUC application filing and approval process, not all sources of regulatory lag relate to BCUC approval processes. FEI is seeing increased

[164] BCUC IR1 3.4 and BCOAPO IR1 1.2 as examples.
[165] Decision and Order G-366-21 pages 23 to 25.

requirements for stakeholder consultation, environmental reviews, and Indigenous consultation which may also lead to increasing costs and delays in all regulatory approvals.

In response to the requirement to seek the FPIC of Indigenous Peoples prior to proceeding with project development (as discussed in Sections 5. 1 and 5.2), FEI must engage with Indigenous groups earlier and more often in support of building relationships, engaging in meaningful dialogue and seeking consent for its projects. Depending on the nature of the project, this means that engagement can begin at the outset before FEI has developed project alternatives so that it can incorporate Indigenous knowledge and input into its alternatives evaluation. As a project is developed, FEI engages regularly as it works to select an alternative, evaluate the impacts and develop avoidance and/or mitigation strategies.

The trend towards earlier and deeper engagement with Indigenous groups on project development activities means that FEI's pre-CPCN expenditures are increasing due to an increase in the time required and number of activities that it must undertake to develop a project. This includes increases to FEI's labour costs, the cost to provide capacity funding to facilitate the participation of Indigenous groups and, depending on the nature of the project, the cost of studies that inform project impacts and mitigation strategies.

In addition to higher and earlier costs resulting from changes to regulation regarding Indigenous groups, FEI is seeing increased costs from regulation in other areas. This includes heightened requirements for environmental work in advance of project development, including in some cases Environmental Assessments as described in Section 5.2.2, and fees and requirements for monetary contributions from municipalities as described in Section 9.4. In some cases, the resistance from municipalities has led to higher legal fees as municipalities are increasingly challenging the authority of the BCUC and utilities to undertake infrastructure projects in their boundaries.

The increase in pre-CPCN expenditures represents an increased risk to FEI as these costs must occur in advance of an approval by the BCUC. In some instances, FEI has requested advance approval for development activities such as in its 2022 Annual Review where it requested approval of development costs for the Regional Gas Supply Diversity project.

FEI believes that, as this trend continues, the pre-approval development process will continue to become longer and more costly. As such, there will be a practical need for earlier deferral account approvals. There is uncertainty as to FEI's ability to obtain advance approval for these deferral accounts from the BCUC. Absent the account, there is both increased volatility in FEI's earnings and heightened uncertainty regarding ultimate recovery.

10.2 *ADMINISTRATIVE PENALTIES RISK IS SIMILAR TO 2016 PROCEEDING*

The Administrative Penalties Regulation, brought into effect by OIC 731/2012, provides the BCUC with authority to impose administrative penalties against public utilities that contravene the UCA, or an Order, Standard or rule of the BCUC. Different penalties apply where different sections of the UCA are contravened. There has been no change in the status of the administrative penalty framework since its implementation. FEI has not identified any change in business risk associated with administrative penalties.

BCUC regulation is not the only context where administrative penalties are possible. FEI's business activities continue to be subject to federal and provincial legislation including at the federal level, the *Canadian Environmental Protection Act, 1999, Fisheries Act, Species at Risk Act,* and *Transportation of Dangerous Goods Act,* and at the provincial level, the *Oil and Gas Activities Act, Water Sustainability Act, Environmental Management Act, Heritage Conservation Act, Wildfire Act, and Workers Compensation Act.* FEI continues to face the risk of increasing regulatory requirements and the associated increase in the risk of enforcement action, as well the risk associated with increasing fines and penalties for non-compliance.

British Columbia Utilities Commission 2022 Generic Cost of Capital (GCOC) Proceeding – Stage 1

Appendix B

FortisBC Inc.

Business Risk Assessment

Table of Contents

Index of Tables

Index of Figures

1. OVERVIEW OF BUSINESS RISK

The assessment of a utility's risk profile is an essential element of its cost of capital estimation process. This Appendix describes FBC's overall competitive, operating, policy and regulatory environment using similar categories of business risk and risk factors to those that were used in the company's 2013 Stage 2 Generic Cost of Capital proceeding (the 2013 Proceeding[1]) filings. FBC's overall business risk in this proceeding is best characterized as being similar to what was assessed in the 2013 Proceeding.

1.1 *BUSINESS RISK CATEGORIES AND FACTORS*

FBC identified nine business risk categories, as presented in Table B1-1 below. FBC used similar categories as in the 2013 Proceeding although some risk factors were re-arranged for consistency reasons[2], and the Indigenous Rights and Engagement risk factor has now been promoted to its own risk category. Other risk factors and categorizations are possible, and some risk factors could be captured under a different risk category.[3] However, using similar categories in this Proceeding facilitates the comparison of FBC's risk profile with business risk information presented during the 2013 Proceeding, so as to provide a directional indication.

Table B1-1: Business Risk Categories and Risk Factors Addressed in this Appendix

Business Risk Category	Risk Factors
Business Profile	• Type and size of the utility • Service area • Customer profile
Economic Conditions	• Overall economic conditions
Political	• Energy policies and legislation
Indigenous Rights and Engagement[4]	• Legislative and policy developments • Aboriginal rights and title • Social license / work interruption
Energy Price	• Power supply cost • Competition with electricity • Competition with natural gas
Demand/Market	• New technologies

[1] This was the last time FBC's business risk was reviewed in detail by the BCUC.

[2] For example, risk factors under the demand/market risk category in FBC's business risk evidence for 2013 GCOC proceeding were covered as part of other risk categories (such as business profile risk and price risk). In this evidence, the demand/market risk category was added to make it consistent with FEI's business risk as well as distinguish between demand/market risk and other risk categories.

[3] For example, the energy price risk category has some overlap with demand/market risk category as rate competitiveness challenges affect demand/market risk.

[4] This category was a sub-category of Political Risk in the 2013 Proceeding.

Business Risk Category	Risk Factors
	• Wholesale and Industrial load • Use per customer • End-use market share
Energy Supply	• Security and reliability of supply
Operating	• Infrastructure integrity • Unexpected events • Project resistance • Cybersecurity
Regulatory	• Regulatory uncertainty and lag • Administrative penalties

1.2 SUMMARY ASSESSMENT OF FBC'S BUSINESS RISK

Table B1-2 provides a summary assessment of whether the risk to FBC associated with particular risk categories and factors are higher/lower/similar relative to how they were represented in the 2013 Proceeding or are recognized as a new risk for this Proceeding. At present, while all of the risk categories are important aspects of FBC's overall business risk, FBC highlights **regulatory risk** and **business profile risk** associated with its small size and vertically-integrated nature as the risk categories where changes can have the greatest potential to affect FBC's ability to earn its return on, and of, invested capital.

Table B1-2: Summary of FBC's Business Risk

Business Risk Category	Risk Factor	Change in Risk Since 2013
Business Profile		**Similar**
	Type and Size of the Utility	Similar
	Service area	Similar
	Customer profile	Higher
Economic Conditions		**Higher**
	Overall economic conditions	Higher
Political		**Lower**
	Energy policies and legislation	Lower
Indigenous Rights and Engagement		**Higher**
	Legislative and policy developments	Higher
	Aboriginal rights and title	Higher
	Social license/work interruption	Higher

Business Risk Category	Risk Factor	Change in Risk Since 2013
Energy Price		**Similar**
	Power supply cost	Higher
	Competition with electricity	Higher
	Competition with natural gas	Lower
Demand/Market		**Similar**
	New technologies	Similar
	Wholesale and Industrial load	Similar
	Use per customer	Similar
	End-use market share	Lower
Energy Supply		**Similar**
	Security and reliability of supply	Similar
Operating		**Higher**
	Infrastructure integrity	Similar
	Unexpected events	Higher
	Project resistance	New (Higher)
	Cybersecurity	New (Higher)
Regulatory		**Higher**
	Regulatory uncertainty and lag	Higher
	Administrative penalties	Similar

The key points from this "snapshot" regarding the relative risk of FBC compared to the analyses completed for the 2013 Proceeding, which are discussed throughout this Appendix, are summarized by business risk category below.

- _Business Profile_: FBC is a fully integrated electric utility that owns and operates hydroelectric generating plants, high voltage transmission lines, and a network of distribution assets in the southern interior of BC. FBC's structure as a fully-integrated electric utility contributes to a higher risk profile than for a distribution-only utility of a similar size, a situation exacerbated by a less diverse and relatively small customer base, concentrated in a small, but geographically diverse service area. 25 percent of revenue and more than 30 percent of load is attributable to two customer classes, Industrial and Wholesale, a significant number of which have the ability to receive service from alternate sources of supply with only limited notice. Despite the slight increase in FBC's customer profile risk due to a higher share of the Industrial sector in the company's load and revenue profile, FBC has assessed the overall business profile risk to be similar to what was assessed in the 2013 Proceeding.

- *Economic Conditions*: The current Canadian economic environment continues to be dominated by uncertainty. FBC's assessment of major economic indicators indicates that BC is recovering from the pandemic lows. Nevertheless, the record high inflation rate, caused by government fiscal and monetary policy to boost economic growth and improve employment, and BC's challenges for long-term economic growth points to higher risk. In addition, compared to other larger utilities, FBC's smaller size and dependence on highly cyclical industrial load in one or two sectors contribute to FBC's higher economic related risk.
- *Political Risk*: The government push for electrification of the BC economy is providing FBC with both opportunities and challenges. Namely, government policies to electrify the building and transportation sectors can increase FBC's market share and load; however, rapid policy-driven customer migration from fossil fuels to electricity presents operational challenges for FBC which has limited resources in a small geographical service territory, and government's ability to subsidize BC Hydro customers is not a path open to FBC. Overall, however, FBC assesses that its political risk is lower than what was assessed in the 2013 Proceeding.
- *Indigenous Rights and Engagement*: FBC has made Indigenous Rights and Engagement risk its own category (instead of being one of the risk factors under Political Risk) to reflect the increasing significance of these considerations for FBC's overall business. FBC defines Indigenous Rights and Engagement risk as the potential for utility operations to be negatively impacted by policy or legislation concerning Aboriginal rights and title or by Indigenous groups intervening directly in the utility regulatory process or by asserting Aboriginal rights and title. As provincial and federal governments navigate reconciliation and implement the UN Declaration on the Rights of Indigenous Peoples, FBC has assumed a higher level of business risk related to its relationship with Indigenous groups compared to what it anticipated at the time of the 2013 Proceeding. Indigenous groups in BC are diverse and the added uncertainty from outstanding claims to Aboriginal title and rights further complicates the landscape within which FBC operates. Combined with regulatory updates that have increased consultation requirements and included a focus on seeking consensus and consent of Indigenous groups, as well as the risk of litigation in the absence of consent, FBC faces an elevated risk of cost escalation, project delays and/or projects being denied approval.
- *Energy Price*: The analysis of energy price risk focuses on power supply factors placing upward pressure on FBC's rates and on the competitiveness of FBC's rates. The factors influencing the risk related to FBC's power supply costs are higher compared to 2013. While the risks related to the BC Hydro Power Purchase Agreement (PPA) rate increases remain similar, market price volatility and Brilliant Power Purchase Agreement contract rate risk have increased. Power supply costs impact the level of utility rates, which can influence consumers' energy choices. Specifically, higher electricity rates in FBC's service territory relative to other electricity providers can hinder FBC's ability to attract new

customers (particularly new Industrial[5] and larger commercial customers). In addition, higher electricity rates can discourage residential customers from using electricity for space heating and water heating which can affect FBC's market share and use per customer. Further, FBC's rate competitiveness risk compared to BC Hydro is similar to the 2013 levels but is trending higher. As compared to 2013, FBC's rate competitiveness relative to natural gas is similar; however, given expected increases to gas and carbon tax rates, FBC expects that the trend that has emerged in recent years where its rate competitiveness relative to natural gas is improving will continue in coming years. FBC assesses that its overall rate competitiveness risk is similar to what was assessed in the 2013 Proceeding.

- *Demand/Market*: Emerging technologies can provide challenges for FBC. In particular, alternative sources of energy, such as home solar generation, can reduce the demand on FBC as an electricity provider, while new load requirements, such as EV charging, can conversely increase the load requirements of FBC. Both situations create potential risks for higher costs and to grid integrity and managing the timing of load on the system to avoid peak demand impacts. Also, FBC continues to face demand risk in its Wholesale and Industrial customer segments. This is because FBC's Wholesale and some Industrial customers are able to take service from competing utilities within the province, build generation to serve some or all of their load or purchase electricity from the open market. BC Hydro, whose Industrial and Wholesale rates are competitive with FBC's, continues to be an alternative for FBC's eligible customers. FBC faces risk associated with being highly dependent on load concentration in only two industries – forestry and cryptocurrency mining. The growing share of Industrial load in FBC's load profile contributes to FBC's higher risk since Industrial load is more volatile. Compared to 2013, FBC's residential and commercial use per customer (UPC) values have been on a downward trajectory while Industrial UPC has increased. FBC expects an increase in its electricity thermal market share relative to natural gas and other fuel sources over the longer term as heat pump penetration increases, thereby reducing this aspect of FBC's market share risk from 2013 and current levels. Overall, FBC's demand risk is similar to what was assessed in the 2013 Proceeding.

- *Energy Supply*: The majority of FBC's supply risk has been mitigated through long-term, firm power purchase agreements; although, as these agreements expire, there is no guarantee that FBC will be able to renew them, or that they could be renewed at a similar cost. Furthermore, there is risk associated with FBC accessing supply from the wholesale market. FBC's access to the wholesale market is dependent on FBC's access to Teck's Line 71. FBC has no transmission facilities that connect directly with markets outside of BC, and is dependent on this availability of third-party transmission capacity to serve its customers' growing demand and the potential for increased likelihood of severe weather events such as the June 2021 heat dome and the new all-time peak demand in December

[5] In this document, Industrial customers are those served under the Large Commercial rate schedules, RS 30 and RS 31.

2021. In addition, FBC-owned generating plants are located within the Kootenay region, while most of FBC's customer load requirements are in the Okanagan. Failure of a plant generating unit would result in FBC needing to acquire replacement power which may not be available due to either lack of available supply or lack of available transmission. In addition, the replacement power, if acquired, could be at a significantly increased cost on the open market. Overall, FBC's risk in terms of energy supply is similar to 2013.

- _Operating_: The primary operating risks associated with FBC's generation and infrastructure assets are related to the age and cost to maintain and upgrade these assets. FBC is also exposed to operating risk related to the requirement that the generating units always be available to run for FBC to receive its capacity and energy entitlements as provided for under the Canal Plant Agreement. Failure of one or more of the generating units owned by FBC could potentially result in significant power supply costs to replace the lost entitlements. FBC is exposed to additional risk from its transmission and distribution assets which are primarily above ground, and the potential for increases in unpredictable extreme weather events, such as wildfires and flooding, to compromise the integrity of these assets. Other unexpected events, such as the COVID-19 pandemic, disrupt supply chains and cause delays in FBC's capital work which impacts its ability to maintain and operate its system. Additionally, FBC has experienced an increase in incidences of cyber-attacks and expects to see increased resistance to projects, which will lead to higher risks to execute projects on time at the lowest reasonable cost. Therefore, FBC assesses its operating risk as being higher than in 2013.
- _Regulatory_: The degree to which FBC, as a regulated public utility, is dependent on regulators for timely and objective approvals that directly impact its ability to earn a fair return on and of capital is what is referred to in this section as regulatory risk. FBC has assessed its overall regulatory risk as higher than what was assessed in FBC's 2013 Proceeding, with certain risk factors increasing and others being similar. The BCUC's jurisdiction is confined to what is conferred by the *Utilities Commission Act* (UCA), but within that framework the BCUC has significant discretion in the exercise of those powers. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty which in itself gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FBC with an opportunity to earn its fair return, or that necessary investments are not approved. The underlying regulatory framework remains the same, but there are new developments that merit note. There is uncertainty caused by the BCUC's decision to consider a more generic approach to deferral account financing treatment. The risk associated with regulatory lag and ultimate approval of cost recovery has also increased since the 2013 Proceeding when considering increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title.

Considered together, and despite increased risk in some of FBC's risk categories, FBC's overall business risk is best characterized as similar to its risk at the time of the 2013 Proceeding.

2. BUSINESS PROFILE

As business risk is specific to a particular utility, it is important to understand the fundamental characteristics (or business profile) of the utility being assessed. Discussed below is a high level overview of FBC's business profile. FBC's analysis of its revenue and load profiles by customer sectors and region indicates that, compared to the 2013 Proceeding, FBC's business profile is similar to 2013. The main points discussed in the following sections are:

- FBC remains a relatively small vertically-integrated electric utility. There is no fundamental change in its size or scope.
- FBC's small service area and concentrated customer base contribute to FBC's risk profile.

In the 2013 Proceeding, the BCUC Panel recognized that size-related issues such as concentrated assets and lack of diversity in its customer base affect FBC's risk[6].

Diversity of a utility's service territory is also one of the considerations in credit rating agencies' rating methodology. For instance, 10 percent of Moody's Investor Services (Moody's) scorecard for rating gas and electric utilities' credit quality belongs to diversification.[7]

This section describes FBC's business profile in terms of the nature of the utility (as a vertically-integrated utility) and product offering, size, geographic concentration and customer demand profile. In FBC's assessment, despite the slight increase in FBC's customer profile risk due to a higher share of the Industrial sector in the company's load and revenue profile, FBC has assessed the overall business profile risk to be similar to what was assessed in the 2013 Proceeding.

2.1 *TYPE AND SIZE OF THE UTILITY ARE RELATIVELY UNCHANGED*

FBC is a company incorporated under the laws of the Province of British Columbia, operating since 1897. FBC is a fully integrated electric utility that owns and operates hydroelectric generating plants, high voltage transmission lines, and a network of distribution assets in the southern interior of BC. FBC's structure as a fully-integrated electric utility operating in a relatively small, geographically diverse service area is a defining characteristic of its business risk profile.

FBC currently serves, directly and indirectly[8], over 183,000 customers. FBC's electricity service is provided through approximately 1,300 kilometres of transmission lines and 6,000 kilometres of distribution lines. FBC's network serves approximately 8 percent of electricity customers (direct and indirect) in BC and delivers more than 5 percent of the total energy consumed in the province.

6 2013 Stage 2 GCOC decision, p. 68.
7 Moody's Investor Services, "Rating methodology" Regulated electric and gas utilities".
8 FBC indirectly provides electricity to the customers of four municipal electric utilities through FBC's Wholesale tariffs. The City of Penticton, Corporation of the City of Nelson, City of Grand Forks, and the District of Summerland buy Wholesale service from FBC to serve their customers.

Table B2-1 below summarizes FBC's business profile in 2013 and in 2022. The importance of Industrial load and revenue is increasing in importance in FBC's business profile.

Table B2-1: FBC's Business Profile

	2013 Actual	2022 Approved[9]
Type of Utility	Integrated Utility with Generation, Transmission and Distribution assets	
Energy Product Offering	Electricity	
Service Area	South Central Interior of British Columbia	
Mid-Year Rate Base ($000s)	1,142,132	1,582,907
Sales Volumes (GWh)	3,211	3,306
Number of Direct Customers	128,318	147,199
Number of Indirect Customers	35,520	38,432
Customer Profile by Consumption		
Residential	45%	39%
Commercial	22%	29%
Wholesale	22%	17%
Industrial	9%	14%
Other	2%	2%
Customer Profile by Sales Revenue		
Residential	52%	49%
Commercial	22%	26%
Wholesale	16%	13%
Industrial	9%	10%
Other	2%	2%

Note to Table: Percentage may exceed 100% due to rounding.

As will be explained in various sections of this evidence, FBC's vertically integrated structure contributes to a higher risk profile than for a distribution-only utility of a similar size. This is corroborated by an S&P Global examination of major rate case decisions in the U.S. released in July of 2019 which found that,"… *the annual average authorized ROEs in vertically integrated*

[9] Financial schedules included in Compliance Filing to BCUC Decision and Order G-374-21.

cases typically are about 30 to 65 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets."[10]

As explained in Moody's rating methodology document, diversification of a utility's generation mix as well as low exposure to challenged sources of generation are two main factors that are considered for rating generation assets:

> Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources[11], will incur lower scores[12].

In terms of generation assets, FBC owns four hydroelectric generating plants on the Kootenay River with an aggregate maximum generating capacity of 225 megawatts (MW) and an annual gross energy entitlement under the Canal Plant Agreement (CPA) of approximately 1,596 gigawatt hours (GWh). FBC meets the remainder of its customers' energy and capacity requirements through a portfolio of long-term and short-term power purchase contracts which includes its PPA with BC Hydro, the Brilliant Power Purchase Agreement, and agreements with a small number of small Independent Power Producers. As explained in Section 8.1, concentration of FBC's generation assets on one source, the Kootenay River, adds to FBC's risk. Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River in order to protect the environment. This adjustment could affect the amount of water available for generation at FBC's plants which in turn could cause adjustments to the CPA entitlements which can impact FBC's generation capacity and revenues.

In conclusion, FBC submits that its vertically integrated nature adds to its business risk which should be reflected in its authorized return on common equity and/or capital structure. FBC's generation portfolio has not changed since 2013, and FBC assesses that its vertically-integrated nature poses the same level of risk as it did in the 2013 Proceeding.

---

[10] See S&P Global Intelligence, RRA Regulatory Focus, Major Rate Case Decisions January – June 2019 (July 22, 2019).

[11] Moody's defined "challenged sources" as Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.

[12] Moody's; 2017 "Rating Methodology: Regulated electric and gas utilities", p. 17.

2.2 *FBC'S SMALL SERVICE AREA AND CONCENTRATED CUSTOMER BASE CONTRIBUTE TO FBC'S RISK PROFILE*

Diversification across sectors and a larger customer base spread across a larger geographic area reduces the probability of a utility experiencing financial distress. A less diverse and/or smaller customer base concentrated in a small geographic area translates into higher business risks, other things being equal. The following sections describe FBC's limited opportunity to diversify risk due to its small size, limited geographic scope and service area.

FBC operates in a service area in the southern central interior of BC, bordered by the international border with the United States to the south, and on all other sides by the service area of BC Hydro. FBC serves about 30 communities directly and four municipalities indirectly, with the largest population centre in FBC's service being Kelowna, with a population of approximately 143,000[13]. With the exception of the Central Okanagan (which includes Kelowna), annual population growth is below 1 per cent, which limits the growth in load attributable to changes in population.

To illustrate the size disparity between FBC and a larger public utility, consider that in 2020, FEI had about 1,050,000 customers while FBC had approximately 144,000 direct and 38,000 indirect customers. FEI had sales of 231.7 petajoules (PJ) in 2020 while FBC had sales of 3,328 GWh (equivalent to about 12 PJ), making FBC's sales approximately five percent of FEI's. Further, FBC's kilowatt hour (kWh) sales are approximately six percent of the sales of BC Hydro.[14]

FBC's service area is also more rural when compared to more geographically diverse utilities such as FEI and BC Hydro. It does not serve a large population centre such as Vancouver and the Lower Mainland. Geographic areas with more rural populations tend to have less diverse economies with fewer types of industries. This holds true for FBC; this small area of the province is dependent on relatively few industries and this lack of geographic and Industrial diversity adds to FBC's business risk.

Having physical assets concentrated in a limited geographic area also limits operational flexibility. Negative events can have a greater impact on the earnings and viability of a small utility operating in smaller geographic areas. A utility operating in a small geographic area has a greater potential to experience an event that impacts most or all of its service territory and/or load than a utility operating in a larger geographical area. In addition, localized negative events (such as major road closures, adverse weather, etc.) can negatively impact most, or even all, of the service area of FBC with no material impact to the rest of the province.

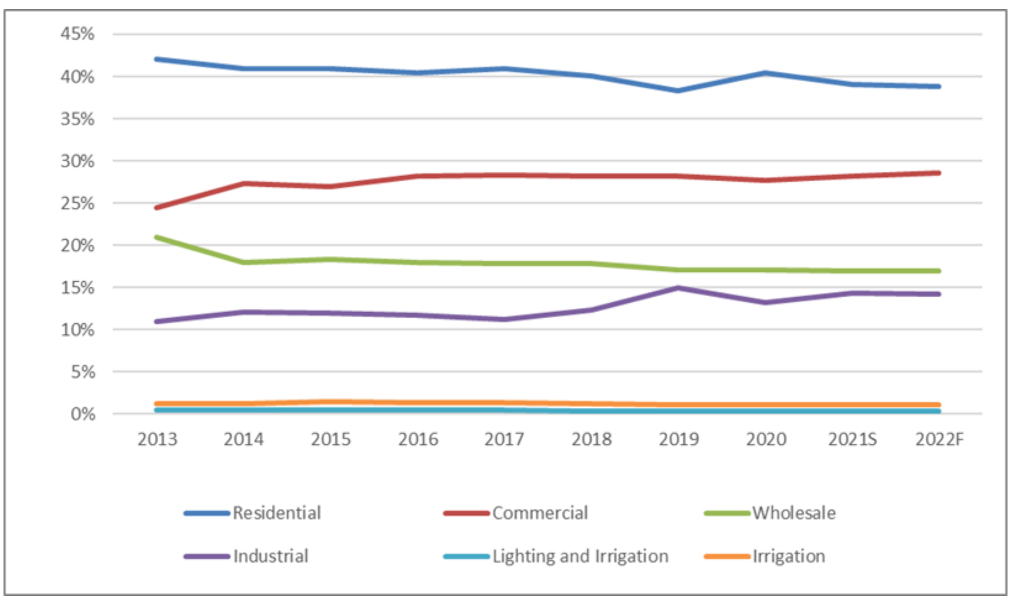
[13] https://www.kelowna.ca/our-community/about-kelowna/city-profile.
[14] Fiscal Year ending March 31, 2020. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/BCHydro-Quick-Facts-20200831.pdf.

The size and location of the FBC service area contribute to a higher risk profile than for a utility with a larger footprint and a geographically and demographically diverse customer base. FBC's geography and service area pose similar risk as in the 2013 Proceeding.

2.3 *SHIFTING CUSTOMER PROFILE PRESENTS DIFFERENT CHALLENGES*

The risk profile of a utility is impacted by its overall customer class composition - that is, the proportion of total customers represented by a single broad customer type, such as residential, commercial, Industrial, and Wholesale groupings. Particularly relevant to FBC, the risk profile is also impacted by the proportion of total load that one particular customer group may comprise, even if the total number of customers in that group may be small. Generally, while diversity of customer characteristics is desirable from a risk perspective, a concentration of a significant proportion of overall load among a small number of customers is not. As shown in the figure below, FBC's customer profile by account type is typical of most utilities in that the majority of customers are in the residential sector. However, as shown in Figure B2-1 and as compared to the 2013-2014 period, the share of FBC's overall load profile in the Industrial sector is on an upward trajectory, increasing from 11 percent in 2013 to 14 percent in 2022. This trend leads to an increase in FBC's risk profile since Industrial load is more volatile and more prone to economic downturns. For instance, in 2019 FBC's Industrial load grew by 23 percent but the economic crises brought on by the COVID-19 pandemic caused Industrial load to drop by 11 percent in 2020.

Figure B2-1: The Trend in FBC's Load Profile by Customer Segment[15]



15 'S' in the chart x-axis labels refers to the Seed Year which is the year prior to the first forecast year in Annual Reviews. 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. 'F' refers to forecast.

Errata dated October 20, 2022

FBC's customer profile by demand is skewed toward a small number of customers due to both the Industrial and Wholesale sectors. The demand profile of a utility is particularly relevant in determining whether the loss of a small number of customers will have a significant impact on the utility due to those customers being associated with a significant amount of demand and revenues. This is the case with FBC where a small number of Industrial and Wholesale customers represents a large portion of overall load and revenue. This aspect of FBC's risk profile is discussed in detail in Section 7.2.

Compared to the 2013 Proceeding, FBC assesses that the increase in share of Industrial load in the company's load profile results in a slight increase to the risk associated with its customer profile.

3. ECONOMIC CONDITIONS

Economic conditions can affect the ability of utilities to attach new customers or retain existing customers and maintain throughput levels, in addition to affecting utility access to capital and cash flow from customers. The economic indicators discussed in Section 3 of FEI's business risk (Appendix A) also apply to FBC's service territory. Similar to FEI, FBC assesses that the record high inflation rate, caused by government fiscal and monetary policy to boost economic growth and improve employment, and BC's challenges for long-term economic growth, point to higher risk.

However, as confirmed by Moody's, economic conditions pose an elevated level of risk to smaller utilities. This is because the smaller utilities have fewer abilities to diversify their operations and protect themselves against economic-driven volatility.

Moody's states:

> While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including Industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility … Economic diversity is typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry … An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.[16]

As such, FBC submits that although its economic conditions are similar to FEI, FBC is faced with slightly higher risk given its small size and exposure to highly cyclical Industrial load in one or two sectors (forestry and cryptocurrency mining).

[16] Moody's Investor Services, "Rating methodology" Regulated electric and gas utilities", pp. 16-17.

4. POLITICAL RISK

FBC defines political risk as the potential for governments or other stakeholders to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, and safety regulations. FBC submits that the government's recent push for electrification is providing FBC with both opportunities and challenges; on balance, FBC assesses that its policy-related risks are lower than what was assessed in 2013 Proceeding.

4.1 *ENERGY POLICIES AND LEGISLATION*

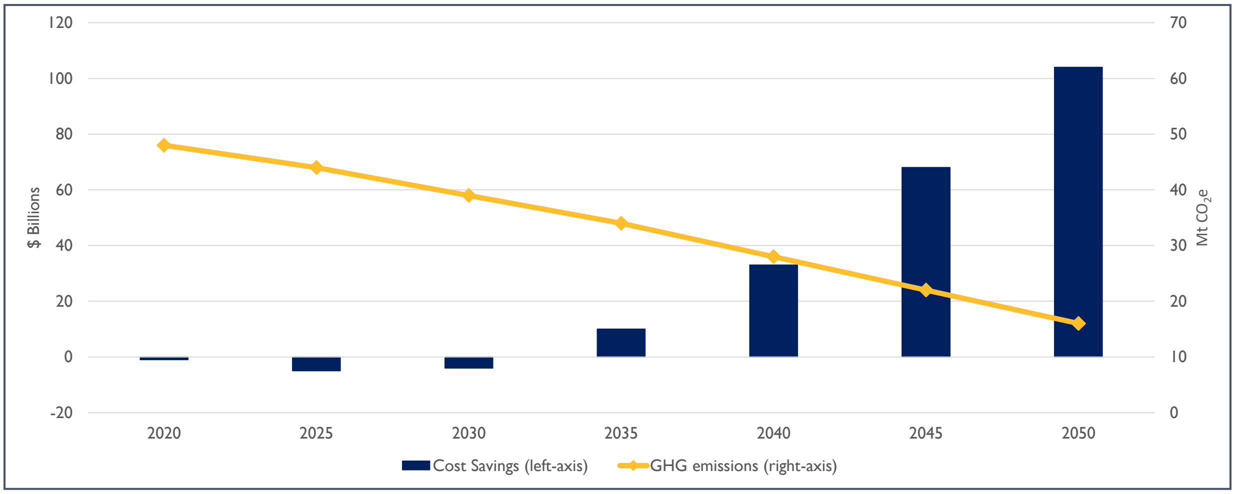
As described in Section 4 of Appendix A (FEI's Business Risk), the British Columbia government and a variety of local governments have been at the forefront of climate change and energy policies. One implication of these energy policies is that in BC, "electrification" is positioned as the preferred option to reduce emissions. For example, the CleanBC Roadmap to 2030 contains a number of policies favourable to growing clean electricity demand, including:

- Accelerating the zero-emission vehicle targets to require 90 percent of light-duty vehicle sales to be zero emission by 2030 and 100 percent by 2035;
- Establishing zero-emission vehicle targets for medium- and heavy-duty vehicles;
- Introducing a carbon pollution standard that requires new buildings to be zero carbon by 2030; and
- Introducing highest efficiency standards that require new space and water heating equipment to meet or exceed 100 percent efficiency by 2030.

From that perspective, electric utilities in the province face a lower risk, although a policy-driven consumer shift from gas consumption to electricity is not without its complications for FBC. In the shorter-term, increased load would be expected to have a favourable impact on rates, so long as there is capacity on the FBC system. However, heating load typically has a low load factor, peaking in winter when capacity is most constrained. A drastic increase in low load factor customer consumption of electricity drives additional investment in more capital infrastructure, which increases utility costs and rates for existing customers. Much like negative growth is a large risk factor to a utility, rapid policy-driven customer migration from natural gas to electricity increases risk and presents operational challenges for FBC which has limited resources in a small geographical service territory.

In 2019, FortisBC commissioned Guidehouse, a global energy consultancy, to develop pathways for BC to achieve its legislated 2050 GHG emissions reduction target of 80 percent below 2007 levels. The Pathways report highlights that pursuing widespread electrification could bring significant long-term costs as the majority of buildings and commercial and light-duty vehicles switch to electricity. An electrification-focused pathway would lead to a less-resilient system that is approximately $100 billion more expensive in annual costs than a diversified energy pathway by 2050. Most of these impacts would be felt after 2030, yet the policies and targets that are implemented today could set BC on this path.

Figure B4-1: Cost Savings of a Diversified Pathway Compared to Electrification to Achieve BC's 80% GHG Emission Reductions



Although this study considered the energy needs of the entire province and not just that of FBC's service territory, the same conclusion can be drawn for FBC, that over-reliance of government policy on electrification as the only solution to the climate change crisis can lead to increased costs to the utility and its customers.

BC Hydro, with its Crown status, has access to a provincial funding backstop that it sometimes uses to recover costs, keep its rates low and minimize its borrowing costs. The same does not apply for FBC as it does not have the ability to use taxpayer funds to cover costs. The BC government's 2019 decision to write-off BC Hydro's rate smoothing deferral account is one recent example of BC Hydro being able to utilize taxpayers to cover costs. On February 14, 2019, the BC government issued a news release stating that… "as part of transitioning to enhanced oversight, government has accepted a recommendation from the review for BC Hydro to stop using the rate-smoothing regulatory account and to write off its balance to zero in 2018-19. This will limit rate increases and relieve ratepayers of the burden of directly paying off $1.1 billion in deferred costs over the next five years.[17] " The government's decision to socialize $1.1 billion of BC Hydro's cost both reduces FBC's price competitiveness with BC Hydro, as well as forces FBC's ratepayers to pay directly for their own utility services, as well as a portion of BC Hydro's bill paid through taxes. As such, the government's ability and willingness to subsidize BC Hydro customers is an increased risk to FBC.

[17] https://news.gov.bc.ca/releases/2019EMPR0004-000231.

5. INDIGENOUS RIGHTS AND ENGAGEMENT RISK

FBC defines Indigenous Rights and Engagement risk as the potential for governments to negatively impact utility operations through policy, legislation and/or regulations concerning Aboriginal rights and title or by Indigenous groups intervening directly in the utility regulatory process or by asserting Aboriginal rights and title. FBC has made Indigenous rights and engagement risk its own risk category (instead of being one of the risk factors under Political Risk in the 2013 Proceeding) to reflect the increasing significance of these considerations for FBC's overall business.

FBC faces an elevated level of business risk related to relationships with Indigenous groups in BC relative to the time of FBC's 2013 Proceeding. This elevated risk is based on the evolving nature of the Crown's relationship with Indigenous groups, developments in reconciliation in Canada, significantly increased expectations among Indigenous groups, and legal claims related to Aboriginal rights and title. Specifically:

- With the significant legislative and regulatory changes described in Section 5.2 of FEI's business risk evidence (Appendix A), expectations regarding reconciliation and free, prior and informed consent (FPIC) have significantly increased (with differing perspectives on the content of FPIC), including, and in particular, in regulatory processes. This has added further uncertainty, risk and cost for FBC in developing and maintaining relationships with Indigenous groups, the development of new projects and ongoing operations and maintenance of FBC's infrastructure.
- Litigation risk and the risk associated with social licence concerns and protests, discussed in Sections 5.3 and 5.4 of FEI's business risk evidence (Appendix A) respectively, are also greater.

6. ENERGY PRICE RISK

The level of utility rates can influence consumers' energy choices. Specifically, higher electricity rates in FBC's service territory can hinder FBC's ability to attract new customers (particularly new Industrial and larger commercial customers). In addition, higher electricity rates can discourage residential customers from using electricity for space heating and water heating which can affect FBC's market share and use per customer.

The analysis of energy price risk in this section focuses on power supply factors placing upward pressure on FBC's rates, and on the competitiveness of FBC's rates. When comparing to the 2013 Proceeding, the main points discussed in the following sections are:

- Section 6.1 addresses how the factors influencing the risk related to FBC's power supply costs are higher compared to 2013.
- Section 6.2 discusses how FBC's rate competitiveness risk compared to BC Hydro is similar to the 2013 levels but is currently trending higher. FBC also assesses that FBC's rate competitiveness relative to natural gas is similar to 2013; however, given expected increases to gas and carbon tax rates, FBC expects that its rate competitiveness relative to natural gas will improve in the following years.

Overall, FBC's risk associated with energy prices is similar to what was assessed in the 2013 Proceeding.

6.1 *INCREASED UNCERTAINTY AROUND POWER SUPPLY COSTS*

FBC's power supply cost is roughly 41 percent of FBC's revenue requirement[18]. The majority of FBC's power supply cost (approximately 36 percent of the total revenue requirement) relates to power purchase expenses, including contract and market purchases, with the rest composed of wheeling expense and water fees.

Overall, FBC faces higher power supply cost and market price risk than in 2013. While the risks related to the BC Hydro PPA rate increases remain similar, market price volatility and Brilliant Power Purchase Agreement contract rate risk have increased. FBC's power supply price risk from these items is discussed in the following sections.

6.1.1 Pacific Northwest Market Risk

FBC relies on the market to meet short-term energy gaps when any unanticipated needs arise as well as to offset purchases under the BC Hydro PPA if and when market supplies are more cost effective. In 2020, FBC obtained 10 percent of its energy requirements through purchases made

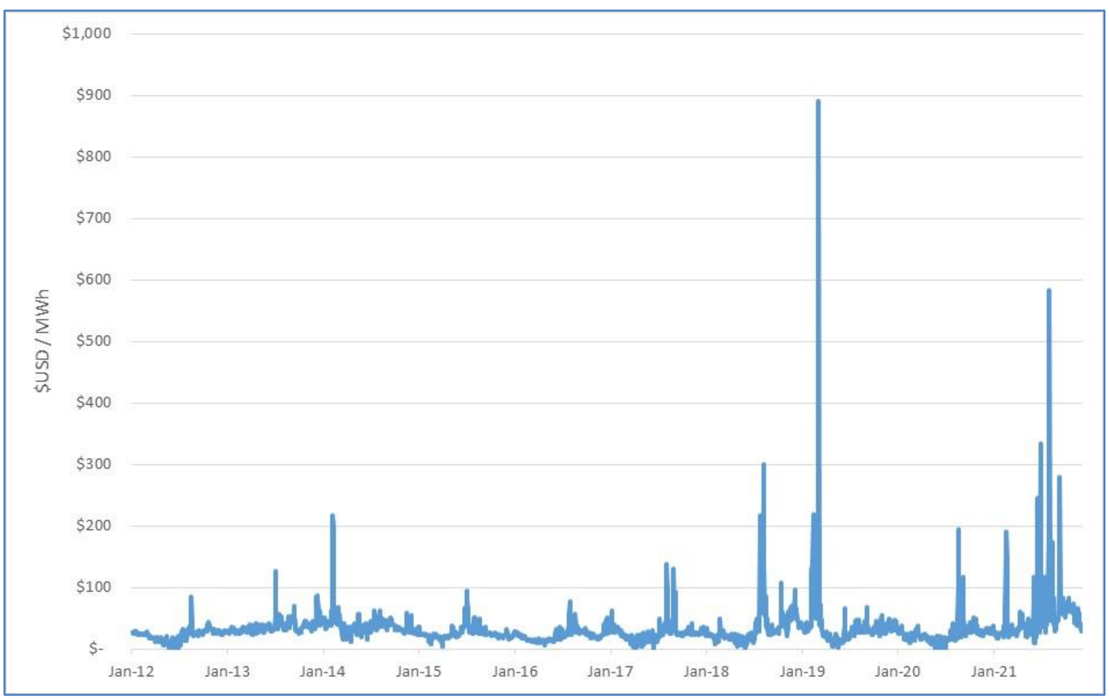
[18] Annual Review of FBC 2022 Rates, Schedule 19.

from the Wholesale market. Increases in the cost of market purchases have a direct impact on the power supply costs to FBC, and therefore to the rates charged to customers.

FBC can purchase energy and capacity from the Mid-Columbia (Mid-C) trading hub, which is a major wholesale electricity trading hub located in the Pacific Northwest (PNW) region. The PNW power market has generally been in an energy and capacity surplus since the mid-2000s; however, due to coal plant retirements in the region since 2018, power markets have become increasingly interconnected with natural gas markets. This stronger reliance on natural gas-fired power plants as the marginal generating unit that sets Mid-C prices has led to increased volatility in recent years, and increased risk to FBC for market purchases. During periods when hydro, wind, and solar resources cannot meet the region's electricity demand, natural gas-fired power plants are required to balance the region. Additionally, as the PNW region has experienced less of a resource surplus over the past few years, there has been increased competitiveness in the Mid-C market, and greater integration to other wholesale power markets, namely California.

The figure below illustrates the volatility associated with the daily Mid-C On-Peak prices. Mid-C prices can be highly volatile over short periods, mainly due to weather changes, regional precipitation and hydro flows. The figure shows that market price volatility has increased since 2013.

Figure B6-1: Day-Ahead Mid-C On-Peak Prices



A further risk to FBC regarding prices is the impact of carbon taxes enacted by federal or state governments, as well as uncertainty regarding the price of a clean market adder. As the PNW region relies more heavily on natural gas-fired generation over the next few years, especially for baseload power, increased carbon prices can increase Mid-C market prices. If FBC were to purchase a clean market adder to certify market purchases as being clean market power, amounts of new renewable generation additions in the PNW could later decrease closer to 2040[19], reducing the oversupply of renewables and increasing the price of certifying market purchases as clean.

6.1.2 There Is Rate Risk Associated with the BC Hydro PPA

FBC purchases approximately 18 percent of the energy and 18 percent of the capacity required to serve its customers from BC Hydro under the PPA at rates contained in BC Hydro Rate Schedule 3808 (RS3808)[20]. The percentage increases in the PPA Tranche 1 energy and capacity rates are the same as those applicable to BC Hydro's customers. This means that cost competiveness with other forms of energy and other providers can be worsened by un-negotiated increases, if introduced, in the PPA rates when and if approved by the BCUC.

BC Hydro has indicated that it anticipates a general rate decrease of 1.4 percent, effective April 1, 2022, followed by an increase of 2.0 percent, effective April 1, 2023, and an increase of 2.7 percent, effective April 1, 2024.[21] FBC does not have any indication or certainty regarding future BC Hydro rate increases beyond March 31, 2025, which would affect Tranche 1 energy and capacity rates.

In addition to the exposure to the general rate increases that affect all BC Hydro customers, FBC could be impacted by any future changes made by BC Hydro that affect RS3808 in isolation. For example, as part of its 2015 rate design application to the BCUC, BC Hydro indicated that it proposes to address the issue of creating a separate rate class for FBC. While it is not clear what the potential impacts of creating a separate rate class for FBC would be, BC Hydro noted that the load factor of FBC is lower than for transmission customers generally, and that it had determined that the revenue-to-cost ratio of FBC was also relatively low (86.6 percent). These factors could give rise to arguments that FBC should bear a greater portion of costs than other transmission level customers, and other customers in general, than currently reflected in RS3808.

6.1.3 Upcoming Market Price Adjustment under Brilliant Power Purchase Agreement

FBC purchases approximately 26 percent of the energy and 19 percent of the capacity[22] required to serve its customers from Columbia Power Corporation and the Columbia Basin Trust Power Corporation (jointly referred to as CPC) under the Brilliant Power Purchase Agreement at rates as set out in the agreement. The Brilliant Power Purchase Amendment Agreement dated May 2, 1996 makes provision for a market price adjustment after 30 years, or 2026. At this time, there is

[19] FBC 2021 Long-Term Electric Resource Plan, Section 2.5.7 Adders to the Market Price Forecasts.

[20] FBC 2021 Long-Term Electric Resource Plan, Section 5.5.

[21] BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application Page 1-50. Rate adjustments are net of general rate increases and that Deferral Account Rate Rider (DARR) rates.

[22] FBC 2021 Long-Term Electric Resource Plan, Section 5.2.

no agreed methodology between FBC and CPC as to how to determine the appropriate market rate. However, given the market price risks described above, there is increased risk to the contract rates under this agreement as compared to 2013.

6.2 RATE COMPETITIVENESS RISK IS SIMILAR

FBC faces competition from both electricity, in the form of less expensive alternative electricity supply, and natural gas. In the following sections FBC's rate competitiveness relative to its main competitors is discussed in more detail. FBC assesses that its rate competitiveness risk compared to BC Hydro is similar to the 2013 levels but may trend higher in the coming years. FBC also assesses that, its rate competitiveness relative to natural gas is similar to 2013; however, given expected increases to natural gas and carbon tax rates, FBC expects that its rate competitiveness relative to natural gas will improve in the following years.

6.2.1 FBC Competes with Alternate Electricity Supply

FBC competes with alternative suppliers of electricity in two main ways.

First, as detailed in Section 7.2, FBC's Wholesale and some Industrial customers are able to take service from competing utilities within the province or purchase electricity from the open market (including the spot market or long-term firm power purchase contracts available through the open market).

Second, and as discussed below, the borders of FBC's service territory tend to be underdeveloped regions, where customers building homes or businesses may have the option between different electricity service providers. As shown in Figure B6-2, the boundaries of FBC's service area adjacent to BC Hydro's service area where growth is most prominent includes the area between the City of Kelowna and City of Vernon, in particular the Lake Country area.

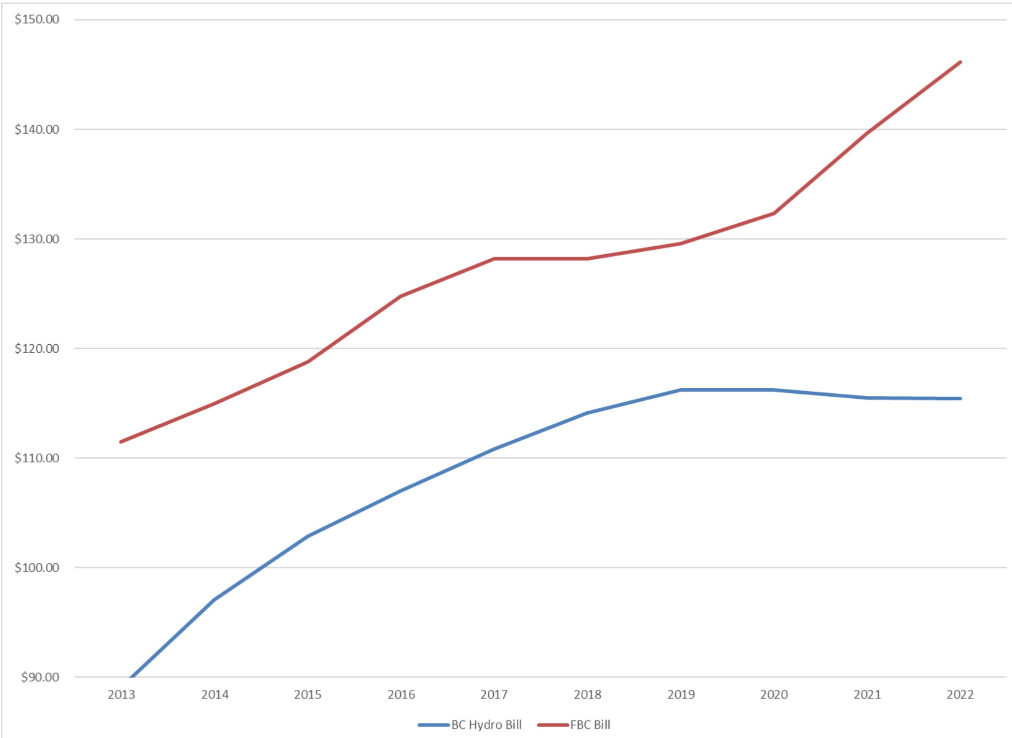
Figure B6-2: FBC Service Territory

FBC competes with BC Hydro in these underdeveloped areas where the borders of FBC's service area and BC Hydro's service area meet. BC Hydro's lower electricity rates are a factor in FBC's ability to expand beyond its currently serviced areas, but within the service area authorized by the *West Kootenay Power and Light Company, Limited, Act, 1897*. Customers building homes and businesses in the boundaries of FBC and BC Hydro service territory are not predetermined customers of either utility. Therefore, competition exists for FBC in these types of areas. The area outside the dark shaded area "FortisBC Service Area" and within the circle is currently served primarily by BC Hydro, although FBC has the statutory authority to expand into that area.

For example, as shown in Figure B6-3 below, based on usage of 1,000 kWh per month and including the basic Customer Charges, an FBC residential customer electricity bill was 27 percent higher than a BC Hydro residential customer electricity bill at January 1, 2022.

Errata dated October 20, 2022

Figure B6-3: Monthly Residential Bill Comparison



The relatively low price of electricity in BC Hydro's service territory compared to other jurisdictions like Alberta and Ontario and FBC's service territory within BC is largely reflective of Heritage or historical costs of supply. A large percentage of the costs making up BC Hydro's electricity rates are the low embedded costs of the province's hydro generation facilities. BC Hydro's current rates also do not reflect the full costs of providing electricity in BC, with significant deficiencies having accumulated in deferral accounts.[23]

As one can see from the general trend in the direction of rates shown in the above figure, BC Hydro rates are actually decreasing in absolute terms in the near term. Even as BC Hydro rates increase in the future, those increases affect FBC's power supply costs and therefore put additional upward pressure on FBC rates. BC Hydro has filed its Fiscal 2023-2025 Revenue Requirements Application with the BCUC, requesting an annual average bill increase of 1.1 per cent for the next three years. BC Hydro received approval for a rate decrease of 1.62 per cent starting April 1, 2021.[24]

[23] Clean Energy BC. Deferral and Regulatory Account Backgrounder. http://www.cleanenergybc.org/media/Deferral_and_Regulatory_Account_BACKGROUNDER_110602_DA_FINAL.pdf.

[24] https://www.bchydro.com/news/press_centre/news_releases/2021/rra-f23-f25.html.

Although BC Hydro must invest in new generation facilities and transmission infrastructure to meet growing demand,[25] it is unclear how the cost of future investments will impact BC Hydro rates given the government's policy of maintaining low electric prices at the Crown-owned utility.

For instance, as explained in Section 4.1 (Political Risk), the BC government's 2019 decision to write-off BC Hydro's rate smoothing deferral account is one recent example of BC Hydro being able to utilize taxpayers to cover costs.

As another example, on December 21, 2020 the BC government issued Order in Council No. 657/2020 (British Columbia) – Direction to the BCUC Respecting Industrial Electrification, (BC Reg. 295/2020), which required the BCUC to approve certain Industrial rates for BC Hydro without any regulatory process and without consideration to the usual regulatory constraints related to the cost of providing service or non-discriminatory access. One of the prescribed rates, *RS 1894 - Transmission Service - Clean B.C. Industrial Electrification Rate - Clean Industry and Innovation* includes substantial discounts of 20 percent for the first five years, 13 per cent and 7 per cent in the sixth and seventh years respectively to the normally available rate. FBC has no such ability to deeply discount the rates it can offer customers.

6.2.2 FBC Competes with Natural Gas

FBC also competes with natural gas for heating load within its existing service territory as the majority of FBC's service area is shared with FEI. Approximately one third of FBC's direct residential sales are for heating purposes,[26] and are therefore subject to competition with natural gas and other alternative sources of heating.

FBC's higher residential electricity rates compared with BC Hydro's residential rates, coupled with FBC's higher heating needs due to relatively colder temperatures in its service area, lead to higher savings for customers that use natural gas as their heating fuel in FBC's service territory compared with the customers in the majority of BC Hydro's service territory. This means that FBC is at a price disadvantage when competing for heating load against natural gas, and that disadvantage is greater for it than for BC Hydro. Even when considering BC's current level of carbon tax and the elimination of the Provincial Sales Tax (PST) for electricity consumption, FBC is currently at a price-related disadvantage to natural gas.

This fact is evidenced by the information shown in the figure below, which shows the approximate annual savings that customers would realize if choosing to heat with natural gas rather than electricity.[27]

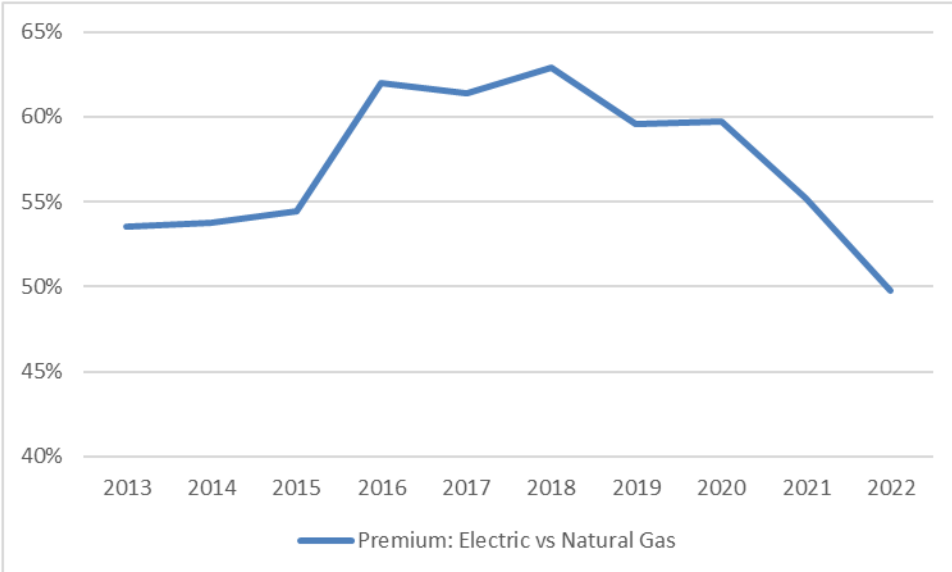
---

25 https://www.bchydro.com/energy-in-bc/projects.html.

26 Section 5.2.1 of FBC 2017 Residential End-Use Study, May 16, 2019.

27 Based on annual natural gas and electricity usage provided by the FBC Energy Calculator (https://www.fortisbc.com/rebates-and-energy-savings/saving-energy-in-your-home/home-energy-calculator for a single detached, new 2000 ft^2 home in Kelowna with 4 occupants. Assumes the difference between an electric

Figure B6-4: The Trend in Annual Energy Savings – Natural Gas vs FBC



Comparing the savings amount between 2013 and 2022 indicates that during this period the natural gas price advantage has decreased slightly. Given recent trends and the expected increases to the carbon tax in the coming years, the natural gas price advantage is expected to decline further.

In summary, FBC faces rate related risks both from the cost inputs that directly influence the rates it can charge customers, and from the relative level of rates in comparison to other utilities. While FBC expects the current disparity between FBC's and BC Hydro's rates to continue and possibly widen in the next couple of years, FBC anticipates some improvement in its price competitiveness against natural gas, both due to increasing gas and carbon tax rates, and increased efficiency of electric space heating equipment.

furnace and a high-efficient gas furnace. For simplicity, rates used were those in effect on January 1 of each year. FBC's annual bills for heating load, based on the Residential RS 03 (Flat) rate excluding the fixed monthly charge.

7. DEMAND/MARKET RISK

Demand risk, also referred to as market risk, generally refers to the risk arising from changes in consumer behaviour and the markets to which the utility has exposure.

When comparing to the 2013 Proceeding, the main points discussed in the following sections are:

- Section 7.1 discusses how new technologies present both an opportunity and a risk for FBC.
- Section 7.2 describes continuing competition for FBC's growing Wholesale and Industrial load.
- Section 7.3 discusses FBC experiencing continued declines in use per customer in residential and commercial sectors while benefiting from higher Industrial use per customer.
- Section 7.4 addresses FBC's expected increasing end-use market share.

Overall, FBC assesses its demand/market risk to be similar to the 2013 Proceeding.

7.1 *NEW TECHNOLOGIES INTRODUCE OPPORTUNITIES AND RISKS*

Emerging technologies relating to alternative sources of energy, such as home solar generation, can reduce the demand on FBC as an electricity provider. While additional EV charging load increases FBC's load, adding EV charging can also create potential risks for higher costs and to grid integrity if charging demand during peak times is not managed. These risks are discussed in the following sections. Overall, FBC assesses that the risk associated with new technologies is similar to the 2013 level.

7.1.1 Increased Adoption of Distributed Generation and Non-Wire Alternatives Increase Risk

Non-wire alternative projects ordinarily refer to the type of projects that would replace, reduce and/or defer traditional capital infrastructure investments that otherwise would be needed to accommodate the growth in expected locational peak demand. Distributed generation (DG) is one type of non-wire solution that can negatively affect FBC's business by reducing the growth in rate base and as a result earnings. Other regulators, such as the New York Public Commission Service, have recognized this risk and have awarded the utilities that adopt non-wire solutions additional financial incentives in the form of return premiums, reduced amortization period or expense capitalization[28].

[28] Please refer to Appendix C4-2 (pp. 38-40) of FortisBC's application in the 2020-2024 MRP proceeding for more detail.

Alternative sources of energy such as solar and wind, and the ability to store energy, are gaining viability as technology improves and costs decrease. In the longer-term, technological change is expected to increasingly create competitive alternatives. In some parts of the world, small economic generation plants are already providing an alternative to expansion of the transmission grid, allowing customers to effectively bypass all or part of the transmission and/or distribution systems. In addition, fuel cells, solar, wind and battery storage are increasingly being viewed as a viable alternative to the traditional grid, and as a result, community-owned energy projects and utility cooperatives are gaining in popularity.[29] There are already a number of examples throughout BC of communities and businesses using alternative energy solutions such as district energy, solar energy and small-scale hydro-generation.[30] In addition to the earnings growth impact, the increase in customer adoption of alternative sources of energy presents new technical challenges for FBC that may lead to increased costs. Intermittent renewable generation creates many new challenges not experienced with conventional integrated utility distribution. Distributed solar PV increases the complexity of managing voltage regulation on distribution feeders due to its intermittent nature. These facilities will have impacts on the distribution system first, and then the transmission system as DG growth continues.

The extent to which DG affects power losses and voltage profiles depends on the type of DG technology, penetration levels, and the location of its connection to the grid. Depending on its location, the integration of DG can reduce power losses on the transmission and distribution network, but as the penetration level increases, the power losses may begin to increase.

If DG uptake increases significantly in the future, FBC transmission and distribution planners will need to have the tools and knowledge for planning and modeling a high-penetration of solar PV, alone or paired with batteries, or other DG technology into the system. There is a risk that alternative engineering designs, technology solutions, and new and updated planning and operations practices that have been implemented in other jurisdictions may be needed for the FBC transmission and distribution system of the future.

The pairing of batteries with solar PV could enable a discharge of stored solar energy during peak demand periods. This type of solar PV plus battery installation could provide a more reliable reduction in FBC system peak demand in a way that solar PV alone cannot, provided that customers discharge the stored energy during peak demand periods. However, the installation of battery systems is not prevalent in the FBC system since the Company's Net Metering program essentially allows the FBC system to store excess customer generation for future use as a "virtual battery" at no cost to the customer.

The increasing penetration of DG resources, such as wind and solar, therefore contributes to a dual pronged and self-exacerbating cycle. First, as customers meet an increasing amount of load from non-utility sources, the load on FBC decreases, as do the revenues that are available to pay for the embedded fixed assets, and rates necessarily increase. Second, the uncertainty created

[29] http://www.trec.on.ca/.
[30] http://www.nelson.ca/223/Solar-Generation.

within the system planning process to meet the evolving needs of a grid that must accommodate the DG, and the infrastructure that must be added to maintain the integrity of the system, puts further upward pressure on rates – potentially driving even more interest in alternative resources.

Customer perceptions regarding the cost and environmental impact alternate sources of supply are increasingly leading to interest in, and actual installation of small scale DG. Surveys conducted by FBC show that many customers believe, for example, that solar PV has an affordability and environmental advantage over grid-supplied electricity, despite the magnitude of the up-front installation costs and clean and renewable nature of existing FBC resources. This increasing interest in and adoption of these alternative forms of energy presents an increased risk to FBC.

7.1.2 EV Charging Load Presents an Opportunity and Challenges

With supportive government policies, EV charging load is expected to increase in the coming years. All else equal, additional EV charging load improves FBC's risk since it would increase FBC's load which helps to mitigate rate pressures. However, increasing EV load in a short period of time or not being able to manage EV charging during peak demand periods can create its own challenges.

FBC faces an increasing challenge with respect to the integrity of its grid due to incremental peak demand imposed by EV loads. This demand depends on the size of the on-board battery, the owners' driving patterns, the charging strategy and the charger characteristics. With improvements in battery efficiency and longer ranges on an increasing number of EV models, customers will require higher electricity demand than that allowed by charging through a conventional 120 V (level 1) outlet. Several electric vehicle chargers on one residential street or a concentration of commercial enterprises utilizing electric fleet vehicles could overload the local distribution transformer unless demand management measures are implemented to shift charging times from peak periods and prevent a possible overload.

Connecting EVs (on Level 2 chargers) to the infrastructure in many older neighbourhoods presents a risk to FBC if not incorporated into local distribution planning. Transformer and conductor capacity in these areas could be an issue. Increasing the capacity of several transformers on a circuit may not be sufficient to address all issues, and a circuit rebuild may be required to mitigate overloaded conductors.

The potential stresses on the electric grid can be mitigated through asset management, system design practices, and managing the timing of charging EVs to shift the load away from system peak by implementing programs or incentives for EV charging customers. A proactive approach that includes understanding where EVs are appearing in the system, addressing near-term localized impacts, and developing both customer programs and technologies for managing charging loads over the long term will effectively and efficiently support EV adoption.

Additional projects and funds are required to meet the additional peak demand requirements imposed by EV loads and raises the risk of increased rates for customers. The timing of these additional projects is very dependent on the peak demand forecast and how it materializes over time. Those projects may not be restricted to the distribution system and could include a 500 kV transmission line project, new distribution substations and feeders, 138 kV transmission line upgrades and additions. There is an appreciable risk related to public acceptance of the above projects, including that related to land acquisition, right of way agreements, environmental and archeological concerns, as discussed in Section 9.3 (Operating Risk).

In summary, while the pace of adoption of new technologies in the FBC service area is somewhat uncertain, it is increasing. The impact of these technologies will add complexity and cost to the FBC system in order to accommodate changing customer needs and to provide system stability. Alternative sources of energy, such as home solar generation, can reduce the demand on FBC as an electricity provider, while additional EV charging load increases FBC's load, but can also create potential risks for higher costs and to grid integrity if charging demand during peak times is not managed. Overall, FBC assesses that the risk associated with new technologies is similar to the 2013 level.

7.2 *THERE IS COMPETITION FOR WHOLESALE AND INDUSTRIAL LOAD*

FBC continues to face demand/market risk in its Wholesale and Industrial customer segments. This is because FBC's Wholesale and some Industrial customers are able to take service from competing utilities within the province, build generation to serve some or all of their load or purchase electricity from the open market (including the spot market or long-term firm power purchase contracts available through the open market). Since 1998, Wholesale and large Industrial customers in BC have been able to obtain open access to BC Hydro's transmission system.[31] FBC's Wholesale and some Industrial customers can choose to buy supply from third parties and transmission service through FBC's and BC Hydro's Open Access Transmission Tariffs (OATT).

FBC assesses that compared to 2013, its risks associated with loss of demand in Wholesale and Industrial load is unchanged. The situation regarding the ability of Wholesale and some Industrial customers to exit embedded cost of service is unchanged from 2013, and while the diversity of and number of Industrial customers has increased, it has done so by adding cryptocurrency load that is of questionable duration.

[31] This development was a result of an Order issued by the U.S. Federal Energy Regulatory Commission (FERC) requiring (i) public utilities under its jurisdiction to provide open access transmission service on a comparable basis to the transmission service they provide themselves, and (ii) foreign utilities that wish to access transmission in the US to implement reciprocal tariffs that permit open access to their own transmission systems. The OATT is the FERC pro-forma tariff, and has been implemented by BC Hydro and FBC to ensure reciprocity is maintained.

7.2.1 Wholesale Load Exposure Continues

FBC currently has four[32] municipal Wholesale customers, accounting for less than one percent of FBC's total customer base, but these four customers make up 17 percent of FBC's load. A loss of any or all of the Wholesale customers to a competing electricity supplier would have a large impact on FBC. If FBC's Wholesale customers elected to discontinue taking service from FBC and pursue any of the opportunities for supply discussed below instead, the loss of their load would result in a reduction of over $51 million in revenue and a substantial rate increase of approximately 6.8 percent for FBC's remaining customers.

As mentioned above, FBC's Wholesale customers have a number of options that would allow them to discontinue taking service from FBC. These include building their own generation to serve some or all of their load, purchasing electricity on the open market or taking service from BC Hydro through its OATT. FBC's Wholesale customers qualify as Eligible Customers as defined under both FBC's OATT and BC Hydro's OATT, and therefore can purchase electricity from the open market or from BC Hydro and wheel over FBC and BC Hydro transmission infrastructure. There is generally available transmission capacity on the transmission system, so access to transmission capacity is not a barrier to FBC's Wholesale customers discontinuing service.

The risk of any or all of FBC's Wholesale customers discontinuing FBC's service increases when some of the following factors are present: FBC's electricity rates increase and the electricity prices on the open market remain competitive; BC Hydro's rates remain lower than FBC's; and, the economics of alternative energy (including, but not limited to, natural gas, distributed generation such as solar and wind power and battery storage) improve. Additionally, all the service agreements between FBC and its Wholesale customers have early termination clauses, allowing FBC's Wholesale customers to exit FBC's service by providing notice.

7.2.2 FBC's Concentrated Industrial Customer Base Has Other Options

A significant portion of FBC's Industrial load is also attributable to a relatively small number of customers. If FBC's largest Industrial customers by revenue elected to discontinue taking service from FBC and pursue any of the opportunities for supply discussed below instead, the loss of their load would result in a reduction of approximately $13.5 million in revenue and a rate increase of approximately 2 percent for FBC's remaining customers.

As is the case with the Wholesale customer class, eligible Industrial customers can also discontinue taking service from FBC by building generation to serve some or all of their load, purchasing electricity on the open market or taking service from BC Hydro through its OATT. Additionally, subject to any previously existing contract requirements, Industrial customers can

[32] As of March 31, 2013, FBC's Wholesale municipal customer count reduced to four customers from five, following the sale of the City of Kelowna's utility assets to FBC. FBC also provides service to BC Hydro under a Wholesale rate to supply customers in the Yahk and Lardeau areas. These loads are not material to the Wholesale total.

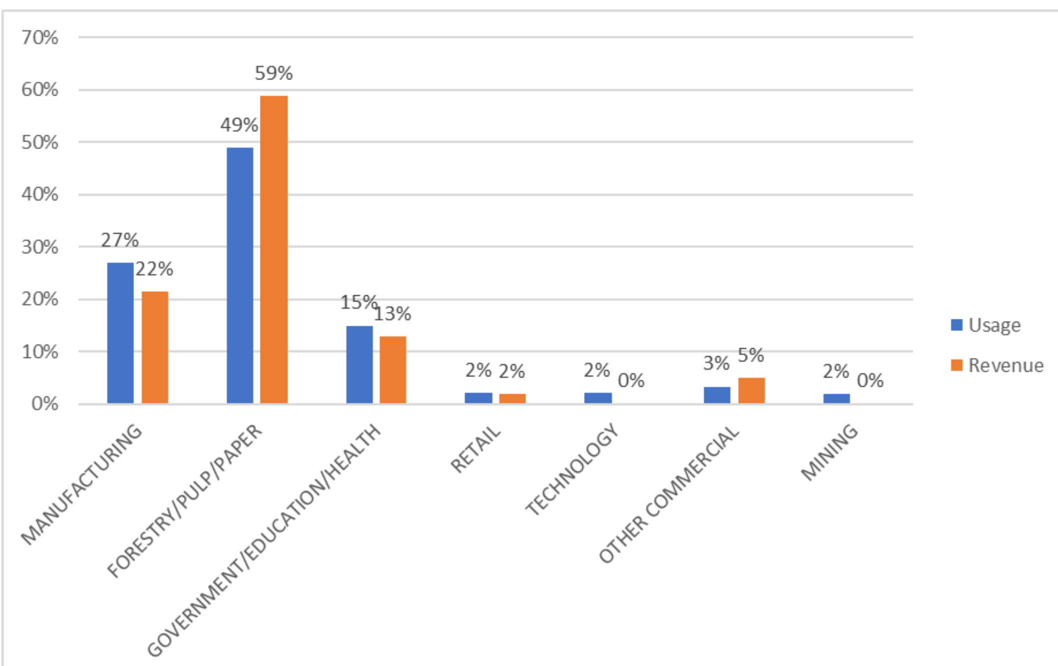
simply shutdown and move to another location as the Terms and Conditions of FBC's Electric Tariff only requires a customer to provide timely notice to FBC of termination of service.

As a general principle, if a utility's customer base is dominated by a small number of industries or large customers, the downturns in, or failures of, any one of those industries or customers is more likely to have a material impact on the utility than downturns or failures in an industry that accounts for a smaller proportion of the utility's overall load. FBC faces risk associated with being highly dependent on single large customers in only two industries – forestry and cryptocurrency mining.

FBC believes that the risk associated with the composition of its largest Industrial and commercial customers has increased slightly in recent years. This is because the mix of load continues to be dominated by a small number of customers in a few industries, namely, those related to the forest sector, as has historically been the case, and now with technology-related load associated with cryptocurrency, the shift from one to the other increases the risk profile.

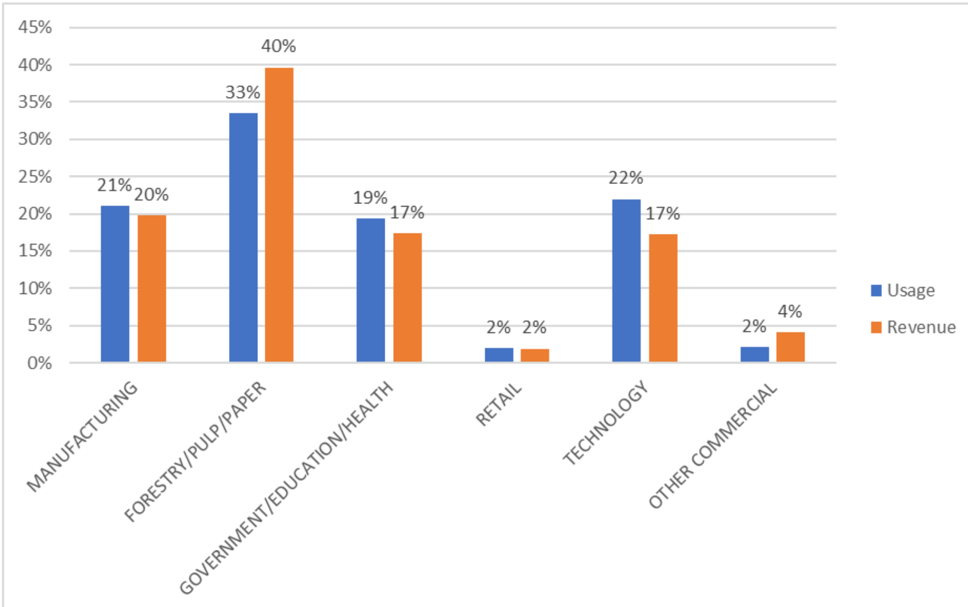
Figures B7-1 and B7-2 below illustrate the changes to the company's load and revenue diversity from 2013 to 2020. In 2013, 49 percent of the load and 59 percent of the revenue attributable to the largest 20 customers was in the forestry industry, which included 9 customers. The other two significant contributors to load were in the manufacturing and institutional sectors, made up of government, education and health related accounts. In 2020, these aforementioned industries remained as key factors in overall load, and the emergence of the technology sector is driven primarily by a single cryptocurrency customer.

Figure B7-1: Industry of FBC's Top Twenty Industrial Customers by Load and Revenue in 2013



Errata dated October 20, 2022

Figure B7-2: Industry of FBC's Top Twenty Industrial Customers by Load and Revenue in 2020



Adding a cryptocurrency customer is beneficial in the sense that it adds new industrial load that is not from the forestry sector, but cryptocurrency mining comes with considerable uncertainty as the utility industry as a whole has little experience with it. Cryptocurrency mining requires large amounts of electricity. Cryptocurrency mining load, however, is heavily tied to market fluctuations of digital currencies. The inherent volatility of the virtual mining industry and its uncertain future creates challenges for electric utilities engaged in long-term resource planning. For FBC, the cryptocurrency industry today is comprised of a single customer. While FBC has no indication that this customer has any intention of being other than a long-term stable load, it is generally understood that cryptocurrency customers are especially price-sensitive and more mobile than is generally the case.

The forestry industry is sensitive to world commodity prices, to the strength of the U.S. and Pacific Rim economies, and to the strength of the Canadian dollar. Factors such as strikes and trade disputes can also negatively impact the forestry industry generally, or specific plants or mills. A downturn or permanent decline in the forestry industry will have secondary effects in the economy, e.g., on commercial enterprises that cater to this industry, as well as on the disposable income of direct and indirect employees. The long-term health of the BC pulp and paper sector is dependent on the BC industry's ability to compete in global markets. The most recent information compiled by the provincial government with respect to the forestry sector is the *2019 Economic State of the British Columbia Forest Sector Report*. The overview from this report notes, "…softened demand in major export countries, a lengthy labour dispute on the Coast, coupled with fibre supply issues caused by the Mountain Pine Beetle epidemic…", as the main factors behind a difficult 2019. National Resources Canada has also produced its annual report, *The 2020 State of Canada's Forests Annual Report: An Overview* which points out that, "…uncertainty in global trade, changes in consumer demands, and increasing international competition are challenging Canada's forest

Errata dated October 20, 2022

sector. In addition, the coronavirus (COVID-19 pandemic has added even greater uncertainty for Canada's forest sector going forward, as the sector grapples with rapid and unexpected changes in global supply and demand as well as concerns with health and safety." While the proportion of Industrial load attributable to forestry related industries has lessened in recent years, it still represents the largest percentage, and the uncertainty surrounding the industry presents a risk to FBC.

7.3 *OFFSETTING CHANGES IN USE PER CUSTOMER*

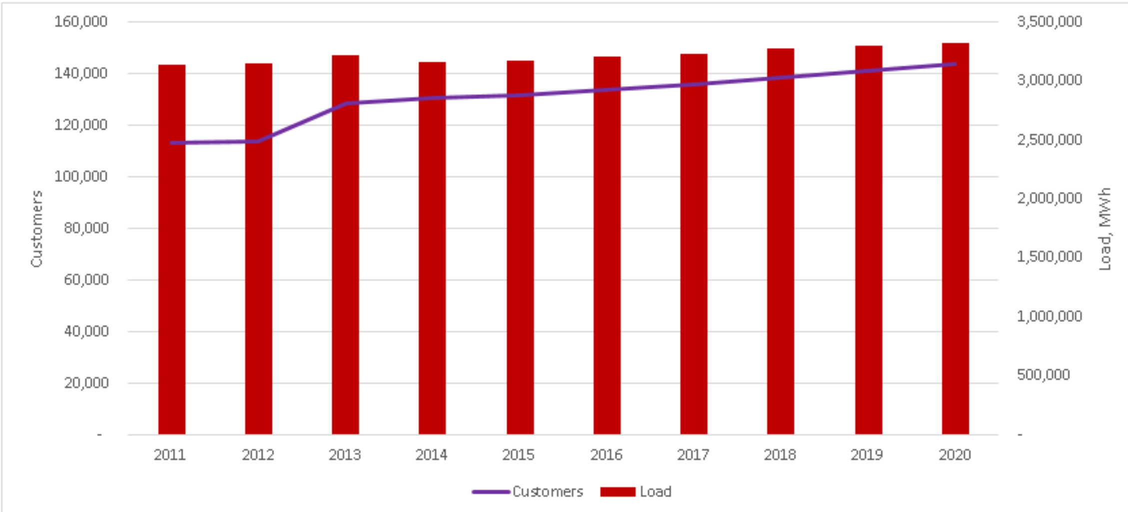
Use per Customer (UPC) is a function of two variables: number of accounts and consumption data for each individual rate schedule. In this section, the aggregate trends and changes in UPC for residential, commercial, Wholesale, Industrial, irrigation and lighting sectors are analyzed.

Overall, the trend in UPC for FBC's customers has been mixed since 2013. While the UPC for residential and commercial customers is down, it has remained unchanged for Wholesale customers while increases have been observed in the Industrial class. This is consistent with FBC's evidence in Section 2.3, indicating that the share of Industrial load in FBC's overall load profile is growing. Therefore, FBC's assesses its overall risk related to UPC as similar to 2013.

UPC Variables at an Aggregate Level

Figure B7-3 below compares the trend in total number of accounts and total load. Between 2013 and 2020 the compound annual growth rate (CAGR) for the total number of accounts and total load are calculated at 1.4 percent and 0.4 percent, respectively. As a result of the customer total growing more quickly than load, the CAGR for the aggregate UPC is declining at 2.2 percent.

Figure B7-3: FBC's Total Load and Total Number of Accounts[33]

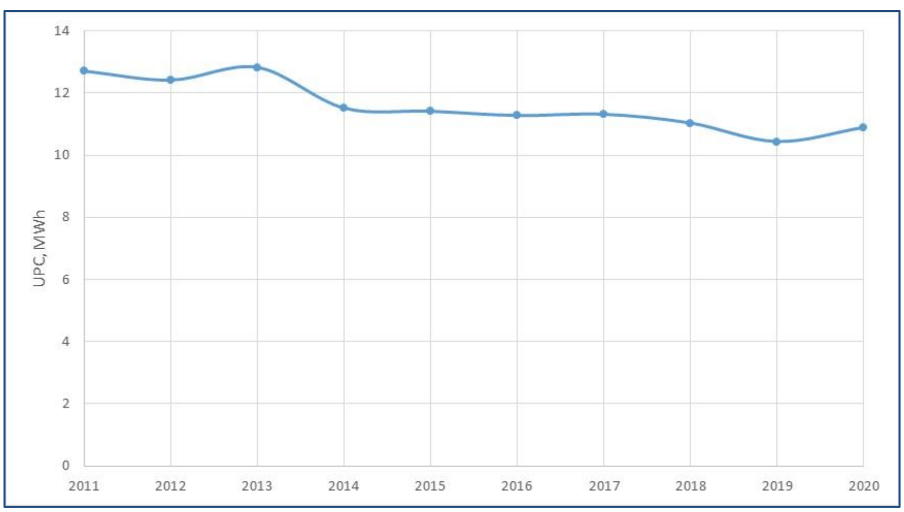


In the following sections, FBC's residential, commercial, Wholesale, Industrial, irrigation and lighting UPCs are discussed at a more granular level.

Residential UPC

As shown in Figure B7-4, during the last ten years FBC's residential annual UPC has fluctuated between 12.70 MWh in 2011 and 10.43 MWh in 2019.

Figure B7-4: FBC's Historical Residential Normalized UPC



The 2020 residential UPC value of 10.89 MWh is lower than the 2013 residential UPC, which may be due to increased efficiencies from light-emitting diode (LED) lighting and building codes and

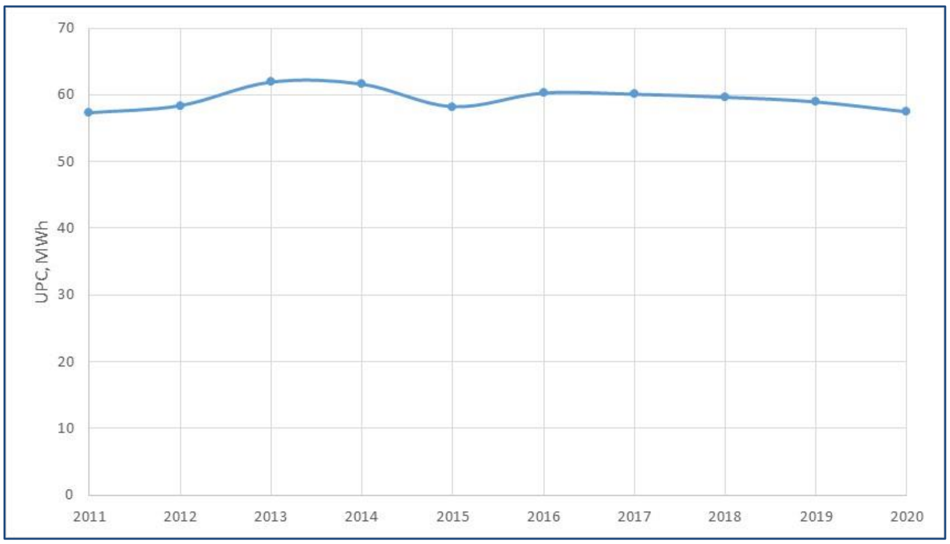
33 The step change in the number of customers in 2013 is due to FBC directly serving the City of Kelowna beginning in 2013.

the increase in building of multi-family dwellings. The slight increase from 2019 to 2020 may be partly related to COVID-19 pandemic impacts as people spent more time at home leading to higher residential consumption. Since 2013, the residential UPC CAGR is -2.0 percent and the residential UPC is expected to continue to decline.

Commercial UPC

FBC's commercial class consists of customers from a wide variety of business sectors. Since this is a very diverse group of customers, there are many factors affecting their electricity use that may lead to changes in the overall average commercial use rate. Figure B7-5 below shows the historical fluctuations in the annual use rate for the commercial rate class.

Figure B7-5: FBC's Historical Commercial UPC



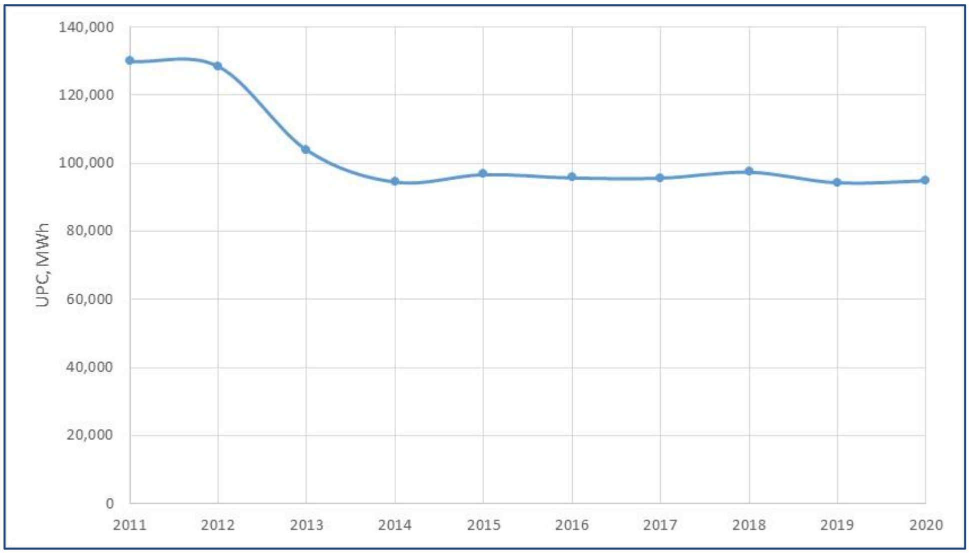
During the last ten years, FBC's commercial annual UPC has fluctuated between 57 MWh and 62 MWh and is overall relatively unchanged from 2011 to 2020. Since 2013, the CAGR has been declining at 0.9 percent which is likely due to the adoption of LED lighting and increased energy efficient building codes. The COVID-19 pandemic has had a negative impact in certain sub-sectors of commercial customers, but higher demand in other sub-sectors has likely lessened the overall impact.

Wholesale UPC

FBC's Wholesale rate class contains six customers, including the municipalities of Penticton, Summerland, Nelson and Grand Forks and BC Hydro interconnections at Kingsgate and Lardeau. The Wholesale customers serve a mix of residential, commercial and Industrial customers.

Figure B7-6 below shows the historical fluctuations in the annual use rate for the Wholesale rate class.

Figure B7-6: FBC's Historical Wholesale UPC

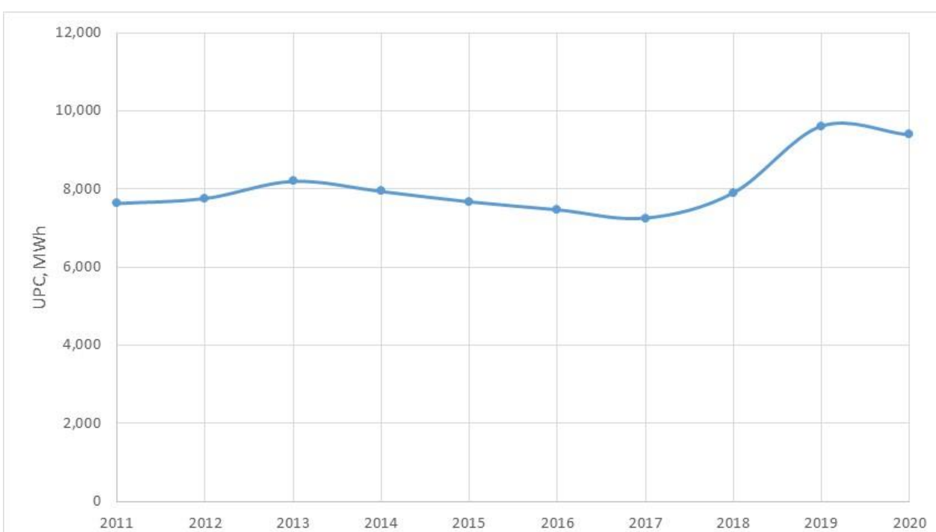


As shown in the figure above, the Wholesale UPC declined significantly in 2013 due to the integration of the City of Kelowna into the FBC system as direct customers instead of a Wholesale customer, but has remained relatively constant since that time. The CAGR for the Wholesale use rate since 2013 is -1.1 percent, and since 2014 has been essentially flat at 0.1 percent.

Industrial UPC

FBC's Industrial rate class consists of customers from a variety of sectors including data centres, forestry, hospitals, and universities. Figure B7-7 below shows the historical fluctuations in the annual use rate for the Industrial rate class.

Figure B7-7: FBC's Historical Industrial UPC

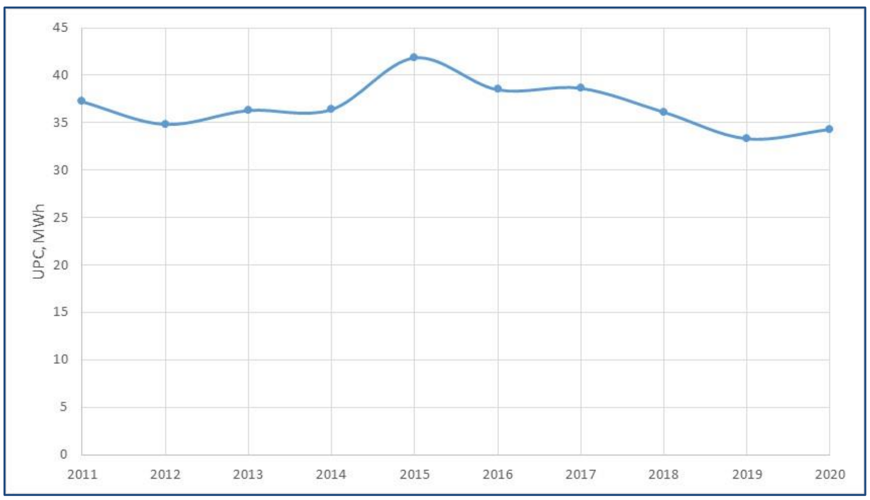


As shown in the figure above, during the last ten years FBC's Industrial annual UPC has fluctuated between 7,627 MWh in 2011 and 9,388 MWh in 2020. The Industrial UPC declined from 2013 through 2017, after which time it increased significantly in 2019 and 2020 due to the addition of a new cryptocurrency mining customer. The Industrial sector includes customers with significantly different energy load characteristics. Further, Industrial customers are sensitive to economic conditions and as such, the Industrial UPCs are more volatile and are not able to be forecast using traditional forecasting methods. Since 2013, the Industrial CAGR has been 1.7 percent.

Irrigation UPC

Figure B7-8 below shows the historical fluctuations in the annual use rate for the irrigation rate class.

Figure B7-8: FBC's Historical Irrigation UPC

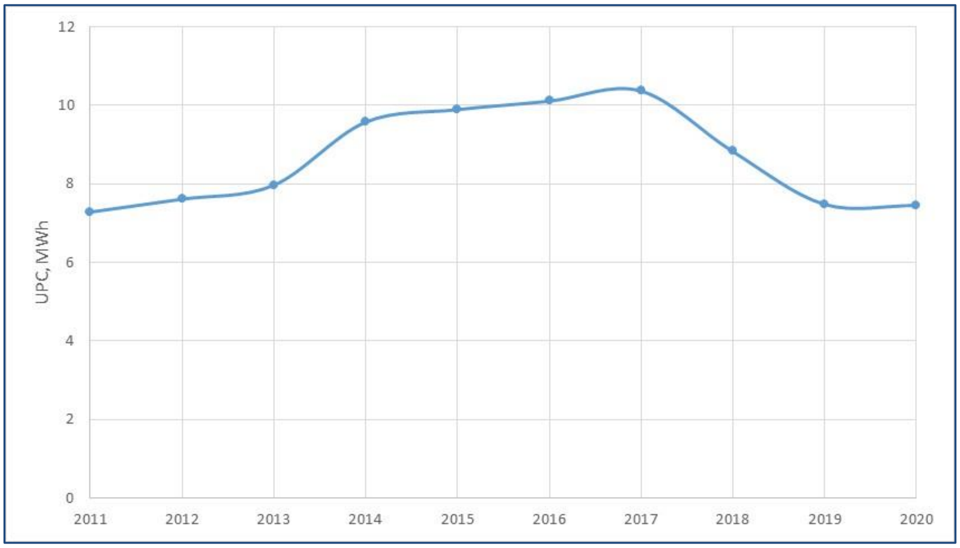


The irrigation class use rates have been relatively stable since 2011, with the exception of a temporary uptick in 2015. Over the past ten years, the irrigation load has accounted for an annual average of 1.1 percent of the total gross energy load for FBC, making UPC fluctuations in this rate class a low risk for FBC. The CAGR since 2013 declined at a rate of 0.7 percent.

Lighting UPC

Figure B7-9 below shows the historical fluctuations in the annual use rate for the lighting rate class.

Figure B7-9: FBC's Historical Lighting UPC



The lighting class has seen some fluctuations in UPC from 2011 to 2020 and the 2020 value is slightly lower than in 2013. The decline in the UPC from 2017 to 2020 is due to the adoption of LED street lights. The load in 2020 is comparable to 2019 suggesting that LED adoption programs are nearing completion. Over the past ten years, the lighting load has accounted for an annual average of 0.4 percent of the total gross energy load, making UPC fluctuations in this rate class a low risk for FBC. The CAGR since 2013 has declined at an average rate of 0.8 percent.

7.4 *FBC'S END-USE MARKET SHARE INCREASING*

As part of its residential end-use study (REUS), FBC asked its consultant, Sampson Research Inc., to conduct detailed surveys that, among other things, gather data on its end-use market. FBC's latest REUS report, published in 2019, is based on survey results from 2017 and can be used to study the trend in FBC's space heating and water heating end-use markets. The REUS indicates that FBC's share of both space heating and water heating end-use markets remains relatively constant since 2009 and 2012, with natural gas market share increasing at the expense of other fuels.

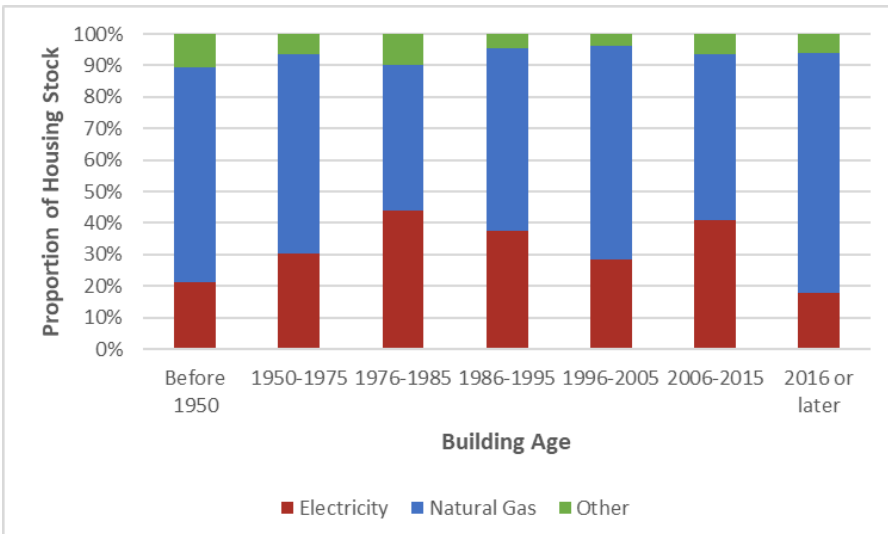
Table B7-1 below summarizes the main space heating fuel used by FBC residential customers. The REUS indicates that, compared to 2009, the use of electricity as a main space heating fuel has remained constant while the use of natural gas has increased and the use of other fuels, including propane, oil and wood, has decreased.

Table B7-1: Main Space Heating End-use by Fuel Type

Fuel Type	REUS Year		
	2009	2012	2017
Electricity	38%	37%	38%
Natural Gas	52%	51%	55%
Other	10%	12%	7%

Figure B7-10 below illustrates the main space heating fuel trend by dwelling age for single-family dwellings for the FBC service area.

Figure B7-10: Electricity Use for Residential Space Heating[34]



The REUS report provides the following comments on the above trend:[35]

> Newer homes (those built between 2006 and 2015) are more likely than homes built in the previous ten year period (1996-2005) to use electricity as the main space heating fuel and much less likely to use natural gas. This is consistent with the increased penetration of air and ground source heat pumps in newer dwellings. While data for the newest homes (those constructed since 2015) suggests a reversal of this trend, the sample is small and future surveys may see this statistic change.

As this comment suggests, FBC expects a reversal of this declining trend in electricity share for space heating in the future as energy policies in BC favour the installation of heat pumps over heating provided by natural gas. However, this trend reversal could take longer to occur in the FBC service area given the greater percentage of fixed incomes and currently higher

[34] FBC 2017 REUS, p. 49.
[35] FBC 2017 REUS, p. 48.

concentration of air conditioning than in areas like the Lower Mainland and Victoria or be slowed by the preference by some customers for other sources of energy, such as solar PV, as discussed in Section 7.1.1.

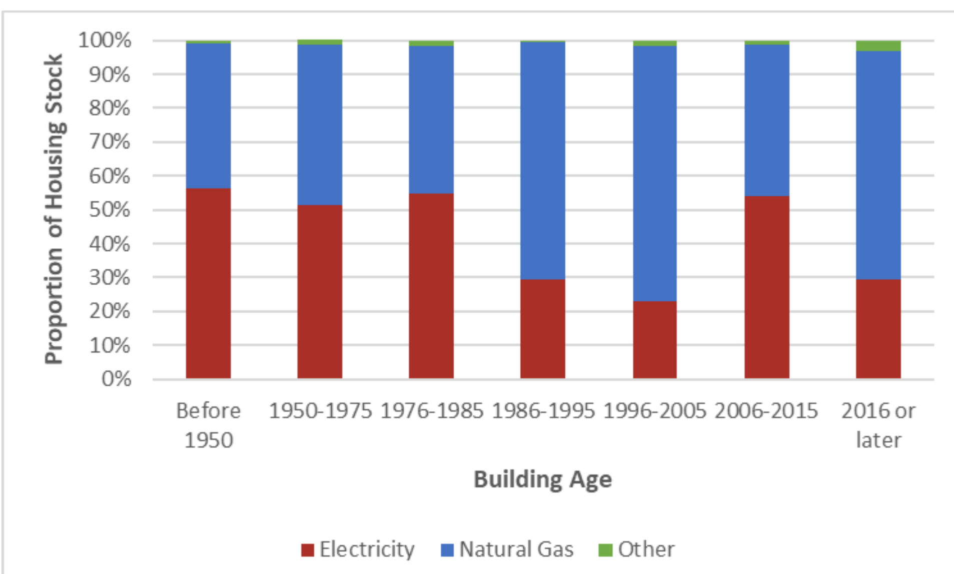
A similar trend is occurring for domestic water heating (DWH). The table below summarizes the percentage of natural gas, electricity and other fuel types in FBC's service territory based on the surveys conducted in the last three residential end-use studies. Its shows that the market share for electricity and natural gas has increased slightly since 2009, with the market share of other fuels decreasing.

Table B7-2: Water Heating End-use by Fuel type

Fuel Type	REUS Year		
	2009	2012	2017
Electricity	49%	53%	52%
Natural Gas	42%	45%	46%
Other	9%	2%	2%

According to the REUS, newer homes are less likely to use electricity for DWH and more likely to use natural gas compared to the stock of homes built prior to 2016. Figure B7-11 below illustrates the trend in DWH fuel by dwelling age for single-family dwellings.

Figure B7-11: Electricity Use for Residential Water Heating[36]



The REUS report explains the above trend as follows:[37]

36 FBC 2017 REUS, p. 74.
37 FBC 2017 REUS, p. 74.

> The proportion of SFDs using natural gas for DWH (main unit) began to increase in the 1986-1995 period before reversing direction for dwellings constructed in 2006-2015. The trend appears to have changed direction again for SFDs constructed since 2015 but the sample of these newest SFDs is small and subsequent surveys may see this share change.

Over the longer term, FBC expects an increase in its electricity market share as the penetration of heat pumps increases, perhaps somewhat offset by other energy sources as mentioned above, thereby improving FBC's market share risk from 2013 and current levels.

8. ENERGY SUPPLY RISK

The following section provides detail on FBC's energy supply risk. As has long been the case, the majority of FBC's supply risk has been mitigated through long-term, firm power purchase agreements; although, as these agreements expire, there is no guarantee that FBC will be able to renew them, or that they could be renewed at a similar cost. Furthermore, there is risk associated with FBC accessing supply from the wholesale market. FBC's access to the wholesale market is dependent on FBC's access to 71 Line, owned by Teck Metals Ltd. (Teck), as outlined in the current Capacity and Energy Purchase and Sale Agreement (CEPSA) between FBC and Powerex Corp. (Powerex). FBC has no transmission facilities that connect directly with markets outside of BC, and is dependent on this availability of third-party transmission capacity to serve its customers' demand. Overall, FBC's risk in terms of energy supply is unchanged since 2013.

FBC generates approximately 44 percent of its energy and approximately 28 percent of its capacity needs from its own hydro generating plants. The remainder of its supply comes from purchased power. FBC has long-term supply contracts with BC Hydro, Columbia Power Corporation, Brilliant Power Corporation and Waneta Expansion Power Corporation. These resources are sufficient to meet FBC's expected[38] capacity requirements until 2030 given the expiry of the Residual Capacity Agreement and FBC's ability to ramp up BC Hydro PPA nomination, despite the expiration of the Brilliant Expansion Agreement in 2027. More significantly, the PPA, under which FBC has firm power supply access to capacity and energy at BC Hydro's embedded costs, expires in 2033. At this time, there is uncertainty that FBC will be able to renew these agreements and at similar costs. If FBC is not able to renew these agreements at similar costs, it may be required to enter into contracts with higher costs or require more costly resources which would increase rates for customers.

In addition to these longer-term contracts, FBC purchases electricity from the domestic (i.e., BC using the BC Hydro system) and PNW markets. Market energy access for FBC is expected to continue through transmission and power purchase agreements, and market energy can be available at attractive prices to FBC during periods of surplus power.

However, there is risk associated with FBC accessing supply from the wholesale market. FBC's access to the wholesale market is dependent on FBC's access to Teck's 71 Line. FBC has no transmission facilities that connect directly with markets outside of BC, and is dependent on this availability of third-party transmission capacity to serve its customers' growing demand, which also needs to consider the potential for increased likelihood of severe weather events such as the June 2021 heat dome and the new all-time peak demand in December 2021. US transmission is required to access the Mid-C trading hub, which is located along the Columbia River on the border between Washington and Oregon. FBC does not hold firm transmission on the US side of the border, but gains access to this via its CEPSA Agreement with Powerex, which is contingent on

[38] The expected load forecast is the 1 in 2 forecast, or the average year forecast. Colder than expected weather will occur on a regular basis and FBC requires additional market-based resources to meet these higher loads. Due to climate change, load variances from the expected forecast may occur more frequently and could be higher in magnitude.

71 Line availability. As such, while the market currently remains a source of energy for FBC, it cannot be considered a long-term resource to meet capacity requirements. Going forward, this increases the risk that FBC is not able to access cost-effective market supply and requires other more costly resources to meet its customer needs.

FBC's owned generation as well as the Brilliant and Waneta Expansion plants are dispatched by BC Hydro in accordance with the CPA. Under the CPA, FBC's rights to the energy and capacity entitlements associated with those plants are subject to the availability of the generating units, however, the current exposure to hydrological conditions is limited. Nonetheless, there is some uncertainty that the CPA will continue indefinitely in its current form. The main risk is that, pursuant to the terms of the 2005 CPA, any time after December 31, 2030, any party to the agreement is able to deliver a five-year termination notice. Given the degree to which the operations of the CPA Parties are interconnected, it would be very difficult to separate them to operate without the CPA or a similar agreement. It is far more likely that rather than resulting in termination, any major issue would be resolved through negotiation. It is possible that such a negotiation could result in a reduced FBC entitlement or additional restrictions on how the existing entitlement is used. If this were to occur, additional resources could be required to make up the difference. An example of an issue that could bring this scenario about is if climate change results in significant changes to the amount and timing of water availability as compared to that assumed under the current CPA.

Additionally, Kootenay Lake levels are governed by the 1938 International Joint Commission (IJC) order on Kootenay Lake[39]. Over the past several years, there has been increased discussion initiated by the IJC on whether or not this order should be reopened. If the IJC order were to be reopened, for instance due to climate change considerations, any changes would have the potential to either increase or decrease the available generation and therefore the FBC entitlements as well. A similar risk arises if a water use plan for Kootenay Lake is mandated by the BC government, which could occur to avoid fish stranding, among other reasons.

Finally, FBC owned generating plants are located within the Kootenay region, while most of FBC's customer load requirements are in the Okanagan. Failure of a plant generating unit would result in FBC needing to acquire replacement power which may not be available due to either lack of available supply or lack of available transmission. In addition, the replacement power, if acquired, could be at a significantly increased cost on the open market.

Overall, FBC assesses its risk in terms of security of supply as similar to the 2013 Proceeding.

[39] The IJC order for Kootenay Lake can be found at https://ijc.org/en/klbc/1938-kootenay-lake-order.

9. OPERATING RISK

Operating risk is defined as the physical risks to the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography, human error, and weather.

Some the operating risk that FBC faces is a function of being a vertically integrated electrical utility. A vertically integrated utility is one that owns all levels of the supply chain, including generation, transmission and distribution. As mentioned in Section 2.1, investors in vertically integrated utilities typically require a premium over distribution-only utilities. Part of the reason for this premium relates to the greater operating risks associated with vertically integrated utilities. FBC operates in a complex operating environment, and the complexity has continued to increase since the 2013 Proceeding due to factors such as: heightened awareness of safety, environmental stewardship, resiliency and reliability; increasing public scrutiny of energy project development; local governments and Indigenous governments seeking to influence energy infrastructure while also maximizing benefits for their communities; and evolving customer expectations.

FBC assesses that, compared to the 2013 Proceeding, the operating risk facing the facilities in the FBC service area is increasing. Specifically:

- Section 9.1 discusses how infrastructure integrity risk remains largely unchanged from 2013.
- Section 9.2 discusses how unexpected events such as recent extreme weather-related events in the province, including record wildfire activity, flooding and mudslides, are expected to continue to occur and become more widespread.
- Section 9.3 discusses how two of the risks (project resistance and cybersecurity) are newly identified operating risk categories since the 2013 Proceeding, and have become significant considerations for FBC.

9.1 *INFRASTRUCTURE INTEGRITY REMAINS A FACTOR*

FBC, as a vertically integrated electric utility, faces risk with respect to the integrity of its generation assets, in addition to its transmission and distribution assets, as discussed below. FBC assesses its risks relating to generation and transmission, substations and distribution assets as similar to 2013.

9.1.1 Generation Risk Associated with Asset Age, Cost to Maintain and Contractual Obligations

The primary increased operating risks associated with FBC's generation assets are related to the age and cost to maintain and upgrade these assets, as well as the consequences of the failure of a generating asset due to FBC's obligations under the CPA[40].

The majority of FBC's generation assets are over 80 years in age, with certain assets exceeding 100 years in age. The primary focus of the capital investments in FBC's generation assets since 1998 has been on the major mechanical and electrical equipment necessary to generate electricity. Since 1998, investment in physical infrastructure (i.e., concrete and structural steel) has been sporadic as capital investment has been focused on electrical and mechanical components of the generation assets which have had a greater priority. To date, FBC has completed the refurbishments of these electrical and mechanical components at all 15 generating units, a program that was started in 1996 and was completed in 2021 with the Upper Bonnington (UBO) Old Units Refurbishment project. FBC faces increased operating risk with respect to the remaining infrastructure related to the 15 generating units that have not seen any refurbishment, such as embedded parts, support brackets, penstocks and draft tubes and are at risk of an increased rate of deterioration.

Furthermore, in order to ensure the long-term viability of FBC's refurbished generating assets, there is a need to invest in the physical infrastructure that supports the electrical and mechanical components that have been refurbished such as excitation and control systems whose service life is relatively short (i.e., 15 to 20 years). The infrastructure integrity risk presented by FBC's generation assets relates primarily to the ability of FBC to plan and execute long-term infrastructure sustainment and replacement programs for these critical assets. The concrete and structural work for these assets is spread over a number of years to ensure regular sustaining investment and prevent large capital expenditures in future years. However, the advanced age and condition of some of the physical generation assets present a risk of an increased rate of deterioration and an increase in construction costs in future years to address this deterioration. Currently, FBC is involved in assessing the condition of the following critical dam structures: intake gate superstructures at Lower Bonnington (LBO), UBO and South Slocan (SLC) dams and free overflow spillways at SLC and UBO dams. Initial findings point to the fact that addressing the deteriorated conditions will result in large and complex capital projects similar to the Corra Linn Spillway Gate Replacement project that FBC undertook in 2017.

40 The CPA is an agreement originally dated August 1, 1972 between BC Hydro, FBC, Teck Metals Ltd. (Teck), and later, through various amendments, Brilliant Power Corporation, Brilliant Expansion Power Corporation, and Waneta Expansion Limited Partnership. Under the CPA, the parties to the agreement cooperate in the operation of their storage and generating facilities in the Columbia River region of BC in order to obtain the optimum generation from BC Hydro's generation resources and the other parties' plants. BC Hydro provides generation and water release operating instructions for the plants included in the CPA, and in return the other parties receive a specified amount of capacity and energy entitlement.

FBC is also exposed to operating risk related to the requirement that the generating units always be available to run for FBC to receive its capacity and energy entitlements as provided for under the CPA. Failure of one or more of the 15 generating units owned by FBC could potentially result in significant power supply costs to replace the lost entitlements. As the owner/operator of these generating assets, FBC is exposed to additional risk related to infrastructure integrity and the potential impact on power supply costs. The requirement under the CPA that the units always be available to run is the same as it was in 2013.

9.1.2 Transmission Operating Risks Primarily Associated with Age, Condition, Above Ground Lines and Configuration

FBC is exposed to operational risk related to its transmission assets. The additional risk is due to the age and condition of the assets, the nature of the commodity being supplied to customers with the infrastructure primarily being above ground, and the configuration of the transmission networks used to supply customers.

FBC's transmission system consists of 62 transmission lines which total approximately 1,300 kilometres. Several of the transmission lines in FBC's system, particularly in the Kootenays, are a vintage of 50 to 70+ years. FBC continually completes rehabilitation on all of these lines based on the 8-year cycle program for condition assessment and rehabilitation. Despite this ongoing rehabilitation work, this asset class continues to age.

It is increasingly difficult to schedule important maintenance and capital work on transmission infrastructure as FBC's windows for these activities continue to shrink. Increasing customer demand and the lack of redundant infrastructure are reducing the options to schedule outages. Environmental constraints, increased safety protocols, work restrictions due to fire danger ratings, lost productivity in extreme temperatures and time spent responding after extreme weather events all act to reduce the hours available to complete planned work.

The infrastructure integrity risk presented by these assets is related primarily to the advanced age and condition of certain portions of the transmission network, and extreme weather events resulting in the unanticipated failure of these assets. FBC is exposed to additional risk from its transmission assets, which are primarily above ground, and the potential for extreme weather events to compromise the integrity of these assets.

An outage on a segment of FBC's transmission network will often result in a corresponding outage to customers if no alternate transmission paths are available around the failed segment. Some of FBC's transmission network is a radial system,[41] and so transmission outages in these areas result in widespread and sometimes lengthy outages. FBC is exposed to operational risk related to the configuration of the transmission networks used to supply customers.

[41] Radial networks leave the substation and pass through the network area with no normal connection to any other supply.

9.1.3 Substation Risk Primarily Associated with Age and Condition

The primary increased operating risk associated with FBC's substations is related to age and condition of the assets.

FBC owns and operates 62 substations throughout its service territory, the majority of which are in excess of 30 years old. The majority of the investment required for FBC's substation assets is related to growth and the replacement of old or obsolete equipment. FBC is exposed to risk in its substations assets, which are primarily above ground, and the potential for extreme weather events such as floods or high winds (with associated falling trees) to compromise the integrity of these assets. Extreme high temperatures such as those experienced in summer 2021 are detrimental to the expected lifespan of major substation equipment and increase the risk of failure.

As with the transmission system, it is also increasingly difficult to schedule important maintenance and capital work on substation infrastructure as FBC's windows for these activities continue to shrink due to environmental constraints, increased safety protocols and lost productivity in extreme temperatures.

In its operations, FBC requires equipment that contains GHGs (like sulfur hexafluoride SF6) or produces GHG emission during its manufacturing process (like insulating oil). If new legislation is put in place in the future to address these GHG emitting sources, FBC could face increased risk in terms of higher equipment costs, longer equipment delivery times and tight deadlines for implementing the required changes. Additionally, the adoption of new and less proven equipment types such as high voltage vacuum breakers would present operational challenges and could result in safety or reliability impacts.

9.1.4 Distribution Risks Primarily Associated with Age, Condition, Above Ground Lines, Configuration and PCB Regulations

Similar to the risks associated with FBC's transmission assets, FBC is exposed to operational risk related to its distribution assets due to the age of the assets, infrastructure primarily above ground, and the configuration of the distribution networks used to supply customers. As well, FBC's federally legislated obligations under the *PCB Regulations* also relate to its distribution assets. FBC is in the process of removing all distribution equipment that contains greater than 1 gram of polychlorinated biphenyls (PCB), according to the PCB mandate, by 2025.

FBC operates a distribution system consisting of approximately 133 feeder circuits with over 83,500 poles, totaling 5,600 kilometres of infrastructure, of which approximately 5,000 kilometres is overhead distribution lines. Although the vintage of FBC's distribution infrastructure is highly variable, the vintage of many assets is greater than 50 years of age. Despite ongoing sustainment capital work, the average age of overhead infrastructure continues to increase. For the same reasons discussed previously, it is also increasingly difficult to schedule important maintenance and capital work on distribution infrastructure as FBC's windows for these activities continue to shrink.

The infrastructure integrity risk presented by these assets is related primarily to the advanced age and condition of certain portions of the distribution network, and the potential for an extreme weather event to result in the unanticipated failure of these assets. Extreme high temperatures such as those experienced in summer 2021 are detrimental to the expected lifespan of equipment such as pole-top and padmount transformers and increase the risk of failure.

FBC is exposed to increasing risk from its distribution assets, which are primarily above ground, and the potential for extreme weather events and outside interference (such as motor vehicle accidents and animal contacts) to compromise the integrity of these assets. An outage on a segment of FBC's distribution network will result in a corresponding outage to customers. An outage on FBC's distribution network may be relatively short if an alternate distribution path can be manually activated to circumvent the failed segment; however, as the majority of FBC's distribution network is a radial system, distribution outages have the potential to result in lengthy outages to customers. Therefore, FBC is exposed to operational risk related to both its assets being above ground and the configuration of the distribution networks used to supply customers.

Distribution assets are also affected by the *PCB Regulations* discussed above. The use of PCB oil for pole-top transformers was an accepted industry practice prior to the banning of PCBs in the late 1970s. Consequently, FBC has many pole-top transformers and other distribution equipment in service that are contaminated with PCBs and must be removed from service by 2025. In the interim period, there remains a prohibition on the release of PCBs in excess of one gram into the environment, and the possibility of penalties including fines of up to $1 million and/or imprisonment for such releases. To date, FBC has replaced approximately 75 percent of PCB contaminated units under the distribution PCB program. Until this program is complete, there remains a risk of unintended release of PCBs into the environment, particularly where incidents such as car accidents occur with relatively routine frequency and could trigger an unintended release of PCB contaminated fluid. FBC is exposed to operational risk related to the historical use of PCB fluids for distribution assets and the legislated prohibition on the release of PCBs, although this risk continues to decrease as equipment is replaced.

An additional risk faced by FBC relates to the presence of legacy copper conductor in the distribution system that is known to be susceptible to failure. In particular, there have been instances of failure where the copper conductor remained energized, creating an electrocution risk and a fire hazard. There is currently no method to maintain bare overhead conductors, so the only mitigation measure available is to replace the legacy copper. As much of the legacy copper has exceeded its useful life, the probability of failure continues to increase. FBC has made progress in replacing these conductors; however, this replacement will remain on-going for some time.

9.2 *FREQUENCY AND IMPACT OF UNEXPECTED EVENTS HAVE INCREASED*

Since 2013, more frequent extreme weather events and the COVID-19 pandemic have highlighted the ever-changing nature of unexpected events facing FBC. In particular, FBC operating risks have increased since 2013 in terms of exposure and damage due to weather-related events associated with climate change.

FBC has a large radial system through mountainous and forested terrain, which is subject to more hazards than a comparable electric utility operating on the prairies, for example. Natural events contributing to operating risk in BC include windstorms, floods, washouts, forest fires, land slippage, extreme temperatures, snowstorms and earthquakes. While the timing of these events is somewhat unpredictable and cyclical in nature, FBC has systems in place to mitigate the impacts of these events. In many cases, pro-active planning can further reduce the impacts of these events. However, given that the extent and frequency of these natural events are increasing, they pose one of the highest operating risks to FBC. FBC faces risk of operational disruptions resulting from unexpected and unpredictable natural events given that the majority of its assets are above ground.

In recent years, FBC has experienced increased risk related to wildfire damage to its infrastructure. As an example, on August 13, 2015 a large wildfire caused significant damage in the Rock Creek/Westbridge area of the Boundary region. 30 customers lost their homes and, due to the nature of the damage, approximately 700 additional customers were left without power. FBC operations staff activated a level 2 emergency in accordance with the corporate emergency response plan and worked at finding a solution to restore power to the affected customers and make repairs to the sections destroyed in the fire. A back-up generator was brought in on August 15, restoring power to approximately 550 customers. Contractors and FBC crews worked around the clock, restoring the main section of the line on August 21, allowing for the back-up generator to be decommissioned. All remaining taps were completed by August 28.

The Nk'Mip Creek wildfire is a more recent example. This fire started approximately 6 km north of Osoyoos on July 19, 2021. The wildfire, which was classified as a Wildfire of Note by the BC Wildfire Service, resulted in evacuation orders and alerts, and burned an estimated area of 19,355 hectares. The Nk'Mip Creek wildfire caused significant damage to FBC's transmission, distribution and fibre optic infrastructure, which resulted in the de-energization of two transmission lines, 48 Line and 66 Line. The load from 66 Line was transferred to 44 Line via distribution network switching. De-energizing 48 Line resulted in a separation of the FBC System between the Okanagan and Kootenay/Boundary areas. The loss of 48 Line and 66 Line did not result in a long-term loss of service for any customers; however, there were system reliability implications, leaving several thousand customers more vulnerable to a lengthy loss of service until the lines were rebuilt.

As another example, FBC has experienced increased risk related to flooding damage to its infrastructure. The Tulameen River and Similkameen River breached their banks on November 14 to 15, 2021 due to rainfall and flash flooding. The flooding caused damage to FBC distribution infrastructure impacting customers in Princeton, Tulameen and Keremeos. As a result of the flooding, two distribution line river crossings were lost and 13 distribution poles were damaged or washed away. It was challenging to restore service to all customers in a timely manner as a result of washed out roads in the area.

Utility power lines and equipment can also pose a fire hazard due to equipment failure. As evidenced by the deadly wildfires in California in 2017, climate-change driven factors such as heat waves and hot winds can increase the possibility of such an incident. Risks associated with fire damage are related to weather, the extent of forestation, habitation, third party facilities located near the land on which the transmission facilities are situated and third party claims for fire-fighting costs and other damages. Such claims could have a material adverse effect on FBC's results of operations and financial position.

The COVID-19 pandemic is another example of an unknown and unexpected event. Operating the electric system through a pandemic can be challenging. The system needs to be operated and maintained appropriately to ensure safe, reliable service to customers. Since the onset of the COVID-19 pandemic, supply chain issues have increased the delivery times for major equipment and caused delays in capital activities for transmission, distribution and substation assets. Disruptions and delays in sourcing adequate supplies of critical parts, components, equipment and materials, whether caused by a pandemic like COVID-19 or some other unexpected event, can impact FBC's ability to properly maintain its system in a safe and reliable manner.

9.3 *PROJECT RESISTANCE CREATES NEW OPERATIONAL CHALLENGES*

There is a higher risk related to resistance to projects to accommodate new generation facilities, substations, transmission lines and distribution feeders in order to meet increasing customer electricity demand. Lands acquisition, Right of Way agreements, environmental and archeological concerns are going to continue to be a challenge in the future and represent a higher risk for FBC.

Protests and environmental activism are becoming more frequent. FBC expects to see increased resistance to new projects, which will lead to higher risks to execute projects on time at the lowest reasonable cost. The impacts of the environmental movement are far reaching. Protests and environmental activism threaten safe and reliable energy delivery to customers. Environmental concerns and general public resistance also represent a risk to FBC's ongoing annual vegetation management programs, which are very important in maintaining safe and reliable service.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, environmental management for sensitive species and their habitat, and conducting environmental impact assessments and remediation. FBC is experiencing increasingly strict environmental and safety laws, regulations and enforcement policies since 2013.

9.4 *CYBERSECURITY HAS BECOME A SIGNIFICANT RISK CONSIDERATION*

Cybersecurity risk is a newly identified risk category in FBC's operational risk section when compared to the 2013 Proceeding. Its inclusion in the evidence reflects the fact that risk of cyber-attacks on energy infrastructure has increased.

Operational risk resulting from cyber-attacks has increased as bad actors and their tools become more sophisticated, and operations has increased their reliance on technological systems and controls. Loss of control of any of these systems or ability to manage critical work is an increasing operational risk. Control systems include sophisticated components that rely on software and network infrastructure to control the electric network and report system status in real time. Sophisticated office and mobile systems provide the ability to manage work and provide office and field employees with critical information to complete work and respond to emergencies such as power outages.

The increasing reliance on systems and infrastructure that is susceptible to cybersecurity threats increases corresponding operational risk.

10. REGULATORY RISK

The degree to which FBC, as a regulated public utility, is dependent on regulators for timely and objective approvals that directly impact its ability to earn a fair return on and of capital is what is referred to in this section as regulatory risk. In the 2013 Stage 1 GCOC decision, the BCUC acknowledged level of influence of the regulatory framework on utilities when it stated that "the BC regulatory framework has a significant influence on FEI's business and that individual decisions can have significant implications for FEI".[42] A stable and supportive regulatory environment is also one of the main factors that is considered by credit rating agencies.

FBC has assessed its overall regulatory risk as higher than what was assessed in the 2013 Proceeding, with certain risk factors increasing and others being similar. The main points discussed in the following sections are:

- Section 10.1 discusses how there is an increased level of regulatory uncertainty driven by the BCUC's decision to review the financing of deferral accounts, and increased potential for regulatory uncertainty and lag around project approvals and increased requirements for environmental reviews, and consultation and engagement.
- Section 10.2 explains how, although regulatory requirements are getting more complex and expansive, FBC has nonetheless characterized its risk exposure associated with administrative penalties under the UCA and other regulatory frameworks applicable to FBC as similar to the 2013 Proceeding.

10.1 *INCREASED RISK RELATED TO UNCERTAINTY AND LAG IN REGULATORY APPROVAL*

FBC is subject to a number of regulatory regimes, with BCUC regulation being notable. As a regulated public utility, FBC can only construct significant utility assets with a CPCN approval. It can only charge rates that have been approved by the BCUC. The BCUC sets the allowed return on equity and capital structure of the utility, and assesses depreciation rates that permit recovery of invested capital. The BCUC, as a statutory entity, acts pursuant to its power under the *UCA* but, within that framework, has significant discretion in the exercise of those powers. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty. Regulatory oversight gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FBC with an opportunity to earn its fair return on and of invested capital, or that necessary investments are not approved.

[42] 2013 GCOC Stage 1 Decision, p.40.

Overview of Current Regulatory Framework

There has been no fundamental change in FBC's regulatory framework under the UCA since the 2013 Proceeding. However, the BCUC's decision to review the financing of deferral accounts as part of this Proceeding has introduced additional risk.

10.1.1

10.1.1.1 2020-2024 MRP Decision

In 2013, FBC's revenue requirement was set under a cost of service model. In 2014, the BCUC approved a performance-based rate-setting (PBR) framework for FBC for a term of 2014 to 2019. More recently, in June of 2020, BCUC Decision G-166-20 approved FBC's Multi-year Rate Plan (MRP) for a five-year term (2020 through 2024). The approved 2020-2024 MRP includes, amongst other items, a level of O&M expense per customer indexed for inflation less a fixed productivity factor of 0.5 percent, a forecast approach to capital, a number of service quality indicators and a symmetrical sharing between customers and FBC of variances from the allowed return on equity. Overall, FBC believes that the risks associated with the MRP are comparable to the risks identified for its 2013 cost of service revenue requirement model.

10.1.1.2 FBC's Deferral Accounts Similar to 2013

Deferral accounting can help to reduce the rate impact and rate volatility for customers. The BCUC determined in the 2009 Cost of Capital Decision that "…the effect of deferral accounts in reducing the risk of [FEI] as reducing the short-term, and not the long-term, business risk of [FEI]..."[43] and this statement is equally applicable to FBC. In other words, deferral accounts can delay the short term rate impact of risk events but cannot eliminate risks.

The majority of FBC's deferral accounts have been put in place to ensure forecast variances do not result in costs being inappropriately borne by customers or the Company. In the 2014 PBR Decision, the BCUC directed FBC to discontinue the use of several deferral accounts;[44] however, the discontinuance did not, in and of itself, materially change FBC's short-term risk profile since the BCUC also directed FBC to true-up those costs each year through a flow-through mechanism for the term of the PBR Plan. The rest of FBC's key deferral accounts remained unchanged.

In the 2020-2024 MRP Decision, the BCUC approved a similar flow-through mechanism, however, that mechanism was modified to exclude certain controllable variances related to O&M, other revenue, depreciation, interest and taxes[45]. Instead, any variances between actual and forecasted revenues and costs for those items would now be subject to 50/50 sharing with customers.

Table B10-1 summarizes the general categories of FBC's deferral accounts.

---

[43] 2009 Cost of Capital Decision, p. 19.
[44] Power Purchase Expense variance deferral account and the Revenue variance deferral account.
[45] Order G-166-20, Page 74.

Table B10-1: Deferral Accounts

Deferral Account Category	General Purpose & Description
Energy Policy	• Capturing costs associated with energy policies that focus on energy efficiency, conservation and the environment • Deferring and amortizing these costs matches the costs of the programs with a reasonable period of time over which the benefits are expected to be realized by customers Example: Demand-Side Management (DSM)
Non-Controllable Items	• Items which are either outside of the Company's control or where the Company has limited ability to influence the costs • Deferring the variances from the forecast level of costs for these activities reduces the exposure for both the Utility and customers due to significant variances in these amounts, and serves to avoid windfall gains or losses to the Company or to customers Examples: Flow-through deferral account, Pension and OPEB Variances, BCUC Levies Variance, MRS 2021 audit costs
Costs of BCUC Applications	• Captures costs required to support regulatory applications, such as intervener and participant funding costs, Commission costs, costs for expert witnesses and consultants, costs related to independent validation of study results, legal fees, required public notifications, and miscellaneous other costs Example: 2020-2024 MRP Application Costs deferral account
Other	• Various accounts that provide benefits to customers and the Company, often for items that are non-recurring in nature Examples: COVID-19 Customer Recovery Fund, MRP Earnings Sharing Account

10.1.1.3 The BCUC is Revisiting Deferral Account Financing Cost

Currently, deferral account financing treatment is reviewed as part of the revenue requirement applications for individual utilities and reflects the utilities' specific circumstances. However, pursuant to the Industrial Customer Group's request and by Order G-205-21, dated July 7, 2021, the BCUC Panel determined that the review of deferral account financing costs should be subject to a generic proceeding after the completion of stage 1 and stage 2 of the this proceeding. In its decision, the BCUC Panel acknowledged that, "the existence, or lack of, variance and other deferral account treatment can affect a utility's business risks which is a consideration for determining the cost of capital for a utility"[46] but also suggested that it may vary from the established case-by-case review approach and consider whether a consistent approach is appropriate and fair.

As recognized by the BCUC Panel, deferral account financing does impact FBC's business risk since the financing has a direct impact on a utility's earnings. Whereas the approval of a deferral

[46] Exhibit A-6, Appendix A, Page 3.

account addresses short-term risk by managing the level of costs in rates, usually be smoothing those costs over a period of time, the account does not change the underlying level of cost. This is in contrast to decisions related to the recovery of costs incurred by the utility in financing its deferral accounts, which impacts cost recovery itself. The decision to revisit deferral account financing costs itself creates uncertainty for FBC and investors. Moreover, a more generic approach to deferral account financing can lead to approval of unfair and inappropriate financing treatment if a utility's specific circumstances are not be fully recognized.

10.1.2 The Potential for Regulatory Lag has Increased

The growing complexity of FBC's operating environment can lead to delays (regulatory lag) in system investments, or the delivery of service offerings. Regulatory lag, which can be associated with BCUC or other regulatory processes, can present a risk for FBC's return on and of capital.

One aspect of regulatory lag is the time between BCUC application filings and final approvals. Given the complexity of the regulatory process, there is going to be an inherent delay between the time an application is filed and when the final order related to that application is issued. While the need to conduct regulatory reviews of utility operations is an integral part of being a public utility, the resulting delay does create risk for the utility. Risk arises in part because it can be necessary for the utility to conduct its operations based on interim rates, with no assurance that the interim rate will be confirmed in the final decision, or the risk that the costs incurred and projects contemplated and required to be undertaken will ultimately be approved. In the case of capital approvals, delays or non-approval can create obstacles for FBC completing projects on time and on budget.

In response to the requirement to seek the free, prior and informed consent of Indigenous Peoples prior to proceeding with project development (as discussed in Section 5.2.1 of FEI's business risk), FBC must engage with Indigenous groups earlier and more often in support of building relationships, engaging in meaningful dialogue and seeking consent for its projects. Depending on the nature of the project, this means that engagement can begin at the outset before FBC has developed project alternatives so that it can incorporate Indigenous knowledge and input into its alternatives evaluation. As a project is developed, FBC engages regularly as it works to select an alternative, evaluate the impacts and develop avoidance and/or mitigation strategies.

The trend towards earlier and deeper engagement with Indigenous groups on project development activities means that FBC's pre-CPCN expenditures are increasing due to an increase in the time required and number of activities that it must undertake to develop a project. This includes increases to FBC's labour costs, the cost to provide capacity funding to facilitate the participation of Indigenous groups and, depending on the nature of the project, the cost of studies that inform project impacts and mitigation strategies.

FBC believes that, compared to the 2013 Proceeding, the risk associated with regulatory lag is increasing. FBC has observed increased interest and active participation from Indigenous and environmental groups in FEI's regulatory proceedings; FBC does not consider this to be a trend confined to the gas utility, as many of the same considerations apply to FBC. For instance, during previous CPCN application reviews such as the Okanagan Transmission Reinforcement and Advanced Metering Infrastructure projects, concerns associated with electromagnetic fields from new substations, transmission lines, and radio-frequency devices were raised by some interveners. Further, some Indigenous groups have suggested there is uncertainty with respect to the BCUC's statutory scope with respect to reconciliation and the duty to consult. This uncertainty increases the regulatory risk associated with FBC's ongoing operations and future regulatory applications, both before the BCUC and elsewhere.

10.2 *FBC FACES ADMINISTRATIVE PENALTIES RISK*

FBC faces the risk of administrative penalties under a variety of statutory regimes. Although the Mandatory Reliability Standards (MRS) framework subject to penalties has expanded considerably since 2013, FBC has nonetheless characterized the overall risk of administrative penalties as similar.

The Administrative Penalties Regulation, brought into effect by OIC 731/2012, provides the BCUC with authority to impose administrative penalties against public utilities that contravene the UCA, or an Order, Standard or rule of the BCUC. Different penalties apply where different sections of the UCA are contravened. For an electric utility like FBC, the risk of penalties is most likely to arise in the context of MRS.

On June 4, 2009 the BCUC, by Order G-67-09, adopted the BC MRS requirements. These standards are substantially in accordance with those previously developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC). FBC is responsible for ensuring that it becomes compliant, and maintains compliance with the applicable standards.

The failure to comply with the adopted BC MRS requirements can lead to the BCUC imposing administrative penalties against FBC. In addition, under the Administrative Penalties Regulation, the prescribed limits for the reliability standard related contraventions are higher than other types of contraventions[47]. Compared to 2013, the scope and comprehensiveness of the BC MRS requirements has increased. FBC strives to comply with the BC MRS requirements, but there is always a risk that non-compliance may occur. The administrative penalties levied against BC Hydro for the contraventions of adopted reliability standards is one recent example[48].

BCUC regulation is not the only context where administrative penalties are possible. FBC's business activities continue to be subject to federal and provincial legislation including at the

[47] A person who contravenes a reliability standard adopted by the commission is liable to an administrative penalty not exceeding (a) $1,000,000, if the person is a corporation, and (b) $100,000, if the person is a director, officer or agent of a corporation that contravenes the reliability standard. Amounts may be imposed for each day the contravention continues, per UCA, s. 109.2(2).

[48] BCUC Order R-18-20, Access at: https://www.ordersdecisions.bcuc.com/bcuc/orders/en/484794/1/document.do

federal level, the *Canadian Environmental Protection Act, 1999, Fisheries Act, Species at Risk Act,* and *Transportation of Dangerous Goods Act,* and at the provincial level, the *Water Sustainability Act, Environmental Management Act, Heritage Conservation Act, Wildfire Act, and Workers Compensation Act.* FBC continues to face the risk of increasing regulatory requirements and the associated increase in the risk of enforcement action, as well the risk associated with increasing fines and penalties for non-compliance.