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February 24, 2023

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

Attention: Sara Hardgrave, Acting Commission Secretary

Dear Sara Hardgrave:

Re: FortisBC Energy Inc. (FEI)

2022 Long Term Gas Resource Plan (LTGRP) ~ Project No. 1599324

FEI Evidentiary Update

FEI writes to provide further evidence in this proceeding in accordance with the regulatory timetable established in British Columbia Utilities Commission (BCUC) Order G-17-23, in the above referenced proceeding.

In its responses to BCUC IR1 30.3 (Exhibit B-6), BC Hydro IR1 4.1 and 4.2 (Exhibit B-8) and BCSSIA IR1 9.1 and 9.2 (Exhibit B-11), FEI discussed how it was in the process of finalizing its Kelowna Electrification Case Study and that it intended to file the study on the record in the proceeding. In response to the BCUC's request in Exhibit A-8, FEI filed a summary of the evidence it intended to file and when it would be able to file it.[1] In Order G-17-23, the BCUC established February 24, 2023 as the date by which FEI was to file the evidence.

In accordance with the above, FEI files the attached Kelowna Electrification Case Study. The Kelowna Electrification Case Study provides information to more fully respond to the round one information requests referenced above.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners

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[1] Exhibit B-18.

FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC)

Kelowna Electrification Case Study – Electrification and the Impacts of Cold Temperature on Peak Demand and System Upgrade Costs

February 24, 2023

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1. INTRODUCTION

FortisBC, which delivers both natural gas (through FEI) and electricity (through FBC) within the City of Kelowna as part of its shared service territory, is in a unique position to develop long-range planning using the City of Kelowna as a case study to illustrate factors that need to be considered in the clean energy transition. With this knowledge from both systems in Kelowna, FortisBC can estimate the impacts that various levels of electrification of gas demand would have on temporal peak electricity demand, meeting electric system capacity needs, as well as the estimated costs to upgrade and develop the required electricity infrastructure to meet future demand. This analysis provides a better understanding of potential electrification impacts on the FortisBC electric system and shows that more work and collaboration is needed to fully understand the implications of electrification.

The results from the Kelowna Electrification Case Study (Study) show that at 100 percent electrification of gas load and a mean daily temperature of -26 Celsius (C)[1], peak demand in 2040 would more than triple, from 472 megawatts (MW) to 1,429 MW[2], resulting in a high-level estimate of between approximately $2.6 and $3.4 billion in capital expenditures on the electric distribution and transmission system which would be needed in less than 20 years. Even at 25 percent electrification of gas load, peak demand would increase to 711 MW and result in an estimated range of $1.3 to $1.7 billion in capital expenditures over this same timeframe. The Study concludes that there are opportunities for solutions to managing the energy transition through the operation of an integrated gas and electric system.

In the following sections, FortisBC presents:

- An overview of the current energy and capacity system demands for the City of Kelowna;
- A simulated representation of peak demand by temperature and levels of fuel switching from natural gas to electricity (electrification);
- The electric system impacts and land acquisition cost estimates associated with meeting this demand, as well as power supply implications; and
- Resiliency considerations for a deep electrification future.

This analysis is followed by a conclusion with respect to the challenges of shifting large amounts of heating customers from two energy systems onto one and suggested next steps to further a holistic understanding of the implications of electrification initiatives.

While the Study examines the extensive electricity infrastructure requirements and cost estimates associated with electrification in the City of Kelowna, Appendix A describes other challenges

[1] -25.9 C is a calculated mean daily temperature (average of the daily high and the daily low) using the extreme value analysis method described in response to BCUC IR1 55.1 and 55.1.1 in the FEI 2022 LTGRP Proceeding (Exhibit B-6). An actual mean daily temperature of -26.2 C was observed at the Kelowna Airport on December 22, 2022, as recorded by Environment Canada.

[2] The 1,429 MW differs from the 1,547 MW provided in the response to BCUC IR1 30.3 due to the modelling inclusion of efficiency improvements for various non-space heating end uses.

faced with respect to building new energy infrastructure in BC. The discussion in Appendix A supports the conclusions that a deep electrification scenario is not plausible within the rapid timeframe required to meet Provincial carbon emission reduction targets and that utilizing both the existing electricity and gas infrastructure in BC will be needed to meet these targets.

The results of this Study are preliminary, should be considered as directional or indicative, and are subject to on-going refinement and more in-depth analysis. This Study is a precursor to further studies of load shifting and optimization technologies, such as hybrid heating systems, peak load shifting pilots, interruptible rates, and generation back-up systems, to understand the impacts of electrification on the combined service territory for FortisBC. The results of these studies could be used as a model elsewhere for optimizing and achieving the lowest cost per greenhouse gas (GHG) emissions reduction.

2. KELOWNA – 2020 CUSTOMER COUNT AND ANNUAL ENERGY DEMAND

In 2020, as shown in Table 2-1, FortisBC provided 5.7 petajoules (PJ) of gas to 43,850 customers, and 1,370 gigawatt hours (GWh) of electricity to 76,250 customers in the City of Kelowna. Table 2-1 below illustrates the annual and peak energy demand, customer count, and energy use per class of customer based on 2020 weather normalized data.[3]

Table 2-1: 2020 Overview of Key Customer and Demand Metrics for City of Kelowna[4]

2020 Metrics	FEI Gas	FBC Electricity
Residential Customers		
Number of Customers	39,325	66,926
Energy (PJ)	3.0	2.4
Energy (GWh)	840	669
Commercial and Industrial Customers		
Number of Customers	4,615	9,324
Energy (PJ)	2.7	2.5
Energy (GWh)	756	701
Total		
Number of Customers	43,850	76,250
Winter Peak Demand (MW)	851[5]	325
Total Energy (PJ)	5.7 PJ/year	4.9 PJ/year
Total Energy (GWh)	1,596 GWh/year	1,370 GWh/year

3 FEI used 2020 data to align with the same base year, data, and analysis in the 2021 Long-Term Electric Resource Plan (LTERP).

4 FortisBC provides weather-normalized gas and electricity consumption data by community to the Climate Action Secretariat (CAS) through the Community Energy and Emissions Inventories (CEEI). CAS acts as the primary distribution channel for this information to local governments for their community energy plans. This information is used below to provide an overview of the current energy demand for Kelowna for gas and electricity and the number of customers for the residential, commercial and industrial sectors.

5 The winter peak demand for FEI's gas customers in the City of Kelowna was calculated to be 3.0 TJ, which is equivalent to 851 MW when converted utilizing a single peak hour factor.

FortisBC forecasts in the FBC 2021 Long-Term Electric Resource Plan (LTERP) that the City of Kelowna will experience increasing energy demand and electric system impacts through population growth, economic development and electric vehicle (EV) growth, in addition to any potential incremental electrification of gas demand.[6] Examining the possibility of electrifying FEI's existing gas customer demand highlights the critical need for long-term holistic planning and optimization of the FEI and FBC energy systems together.

3. PEAK DEMAND AND THE IMPACTS OF GAS TO ELECTRIC FUEL SWITCHING IN THE CITY OF KELOWNA

In the following subsections, FortisBC presents an overview of the energy system demands for the City of Kelowna through a simulated representation of peak demand by temperature. The settings and assumptions of the simulation are discussed further below.

In order to simulate the effects of increasing electricity load through electrification from natural gas to electricity (FEI customers switching to FBC) and the impacts of cold weather on peak demand, FortisBC developed a forecasting model through custom analytics code to illustrate a range of outcomes for the City of Kelowna. The simulation illustrates the increased electricity peak load required over a range of temperatures and incremental electrification proportions. From these simulations with various levels of electrification of gas demand, FortisBC can demonstrate the resulting peak electric demand, which becomes significant in terms of additional system requirements and costs, especially for larger amounts of electrification.

3.1 *ASSUMPTIONS AND STEPS USED IN FORECASTING MODEL FOR GAS TO ELECTRIC FUEL SWITCHING*

The assumptions and steps described in this section were used to develop the base case of electric demand in 2040, in which there is zero percent incremental electrification. The base case demand for the City of Kelowna contains only the electrification (in buildings or vehicles) that was embedded in historical loads. To isolate the impacts that increasing proportions of electrification have on peak demand for the City of Kelowna, the "electrification of gas demand" setting was changed from zero percent to 25, 50, and 100 percent.

For the analysis in this study, FortisBC applied FEI's BCUC-accepted Annual Contracting Plan methodology to forecast gas design day demand[7] to FBC's electric daily demand, which produced a scatter plot of daily demand by average temperature. Within the simulation, the peak daily demand for gas was converted[8] to the electricity equivalent (in megawatt hours (MWh)) and both fuel types were converted to a peak hour factor utilizing internal billing data from 2018 to 2020.

[6] FBC's 2021 LTERP was accepted by the BCUC as being in the public interest per BCUC Order G-380-22 dated December 21, 2022.

[7] The forecast gas design day demand for the Interior region is based on the -25.9 C temperature, which is the same temperature (1 in 20-year return period) utilized for both gas demand and gas system capacity planning.

[8] Gas demand (in GJ) is multiplied by 0.28 to convert to electric demand (in MW). For example, 4 TJ x 1,000 = 4,000 GJ, multiplied by 0.28 = 1,120 MW for a single hour. https://www.convertunits.com/from/gigajoule/to/MWh

The forecasting model then enables FortisBC to model various proportions of gas load shifting to electricity. This model is a top-down, high-level approach representative of an end-state shifting of load due to changes in variable settings. The remaining assumptions to provide the base case of zero percent electrification are as follows:

- The compound annual growth rate (CAGR) of 0.7 percent was used to forecast the increased annual electric and gas demand for a 20-year forecast period to 2040 to align with the assumptions used in the 2021 LTERP Reference Case load forecast;
- The gas residential use per customer (UPC) was held constant[9] to the 2021 UPC of 71 GJ to isolate the impacts of electrifying from increased demand-side management (DSM) measures and gas heating efficiency gains over the forecast period;
- Electric DSM peak saving was applied to each electrification case which provided capacity demand savings from conservation programs at the base case of 0.05 percent per year, which are the assumptions used in FBC's forecasting methodology used in its annual reviews;
- Electric vehicle (EV) charging for Kelowna, prior to any EV shifting solutions, during the peak hour was held constant at 75 MW year-round and throughout the forecast period to align with assumptions in the 2021 LTERP;[10]
- Electric heat pumps are assumed to be the only space heating application in the electrification cases by 2040 for any shifted space heating demand. The efficiency improvement assumed from heat pumps reduces the amount of gas demand from space heating that is shifted to electricity. The efficiency gains for remaining gas load (water heating, cooking, fireplaces) switching to electricity was assumed to be 30 percent; and
- Heat pumps, and their efficiencies as currently represented in the BC Cold Climate Field Study, essentially provide the same efficiency as electric resistive heating at temperatures below approximately -18 C, while the average daily temperature for Kelowna during the winter can be -26 C or lower (with nighttime temperatures well below -30 C). Accordingly, at temperatures colder than -18 C for the 25 percent and 50 percent electrification cases, and at temperatures colder than -20 C for the 100 percent electrification case,[11] it is assumed that heating load is served through the auxiliary / resistive heating mode on the heat pump or by less-efficient electric heating appliances.[12] The thermal efficiency gain

[9] For example, a decrease in UPC by 2040 can be achieved either through increased gas thermal efficiencies or lower gas load due to fuel switching, however in a deep or accelerated electrification future gas DSM measures would not be pursued. This also isolates efficiency gains over time to the electric load over comparable gas use.

[10] In Section 2.3.2 of the 2021 LTERP, FBC notes that the peak demand associated with EV charging, without any initiatives to shift home EV charging from peak demand periods, is approximately 150 MW in 2040 for the FBC system.

[11] For the 25 and 50 percent electrification of demand cases, the forecasting model applies a "Mid" setting, which represents the overall coefficient of performance (COP) of all measured units. For the 100 percent electrification of demand case, the model applies a "Max" setting, representing units with the highest efficiency.

[12] The data utilized for modelling heat pumps is taken from Figure 3.16 of the BC Cold Climate Field Study, available online at: https://www.rdh.com/wp-content/uploads/2021/01/BC-Cold-Climate-Heat-Pump-Study-Final-Report.pdf.

for heat pumps discussed in the above bullet reduces the gas-to-electric conversion only up until those points; after that, the efficiency improvement is lost.

The assumptions are applied to the 25, 50, and 100 percent electrification of demand cases as summarized in Table 3-1 below. The application of these assumptions in the forecasting model results in the ranges of peak demand by 2040 then provided in Section 3.2.

Table 3-1: Summary of Assumptions Applied to Each Electrification Case

	Electrification Case		
Assumptions	**25%**	**50%**	**100%**
Design Temperature	-25.9 C to 29.4 C		
Forecast Duration (Years)	20		
CAGR (%)	0.7		
Residential UPC (GJ)	71		
Electric Peak reduction due to DSM (%)	0.05		
EV Charging during Peak Hour (MW)	75		
Renewable Gas (%)[13]	0		
Non-Space Heating Efficiency Gain (%)	30		
Heat Pump (Min, Mid, Max)	Mid	Mid	Max

3.2 ANALYSIS OF RESULTS IN ELECTRIFICATION OF GAS DEMAND CASES

Table 3-2 below illustrates the hourly peak electricity demand in varying cold temperatures and at increasing proportions of incremental electrification of gas demand.

Table 3-2: City of Kelowna - Electricity Peak Winter Load in 2040 at Cold Temperatures Based on 25 Percent Increments of Electrification

	Electrification Case				
	0%	**25%**	**50%**	**75%**	**100%**
Mean Daily Temperature (C)	**Peak (MW)**				
0	354	415	477	539	555
-5	377	463	548	634	660
-10	400	516	632	748	790
-15	423	581	739	897	984
-20	446	657	867	1,078	1,289
-26	472	711	950	1,190	1,429

The settings and assumptions in FEI's forecasting model determined the design peak demand forecasts at a mean daily temperature of -26 C of 711 MW, 950 MW, and 1,429 MW by 2040 for each of the electrification cases, as shown above. The assumptions used in the model to create

[13] The "Renewable Gas" setting in the forecasting model removes conventional gas load from being converted to electricity under the "Electrification %" setting as the gas demand is instead met through low-carbon and renewable gas.

Table 3-2 are all held constant through the varying levels of electrification.[14] This isolates the impacts that increasing proportions of electrification have on peak demand for the City of Kelowna and implies a significantly higher peak electric demand in cold temperatures under greater electrification cases. For example, at a mean daily temperature of -20 C and 50 percent incremental electrification, the peak demand in 2040 increases by nearly 100 percent compared to no incremental electrification (867 MW versus 446 MW), whereas under 100 percent electrification, this demand increases by nearly 200 percent (1,289 MW versus 446 MW).

As these results demonstrate, higher levels of electrification will impact the peak electric load significantly under cold temperatures.[15] The resulting ranges of peak demand illustrate the challenging scale of shifting energy demand alongside continued demand growth (including from EV charging), with the 1,429 MW peak demand level representing that 100 percent of FEI gas customers in the City of Kelowna are electrified in less than 20 years. This illustration highlights the importance of understanding the peak demand under varying temperatures, and not just the annual energy demand in electrification scenarios. These results were then used to determine the required additional projects discussed later in Section 4.

In the following sections, FortisBC presents figures and discussion for the zero percent, 25 percent, and 100 percent incremental electrification of gas demand cases shown in Table 3-2. For brevity, the 50 percent and 75 percent electrification results have not been shown below but are provided in Appendix B for completeness.

3.3 *ZERO PERCENT INCREMENTAL ELECTRIFICATION OF GAS DEMAND CASE*

The zero percent incremental electrification of gas demand case represents FortisBC's current forecast of demand for the City of Kelowna in 2040, or the "base case" for this study. In Figure 3-3 below, each day of gas and electric demand throughout the year in MW (Y-axis) is illustrated at changing temperatures (X-axis) from -26 C to 29 C for the year 2040. This figure shows that in 2040, with zero percent incremental electrification of gas demand through the 20-year forecast period, a CAGR of 0.7 percent, and EV charging of 75 MW, at a temperature of -26 C, the gas demand in Kelowna is 3.9 TJ (or 1,091 MW equivalent), whereas the electric demand in Kelowna is 472 MW. The 472 MW in 2040 represents a 45 percent increase from the actual peak winter demand of 325 MW in 2020. The slope of the gas demand line in the graph demonstrates that the majority of heating demand in the winter in the City of Kelowna is currently served by the gas system.

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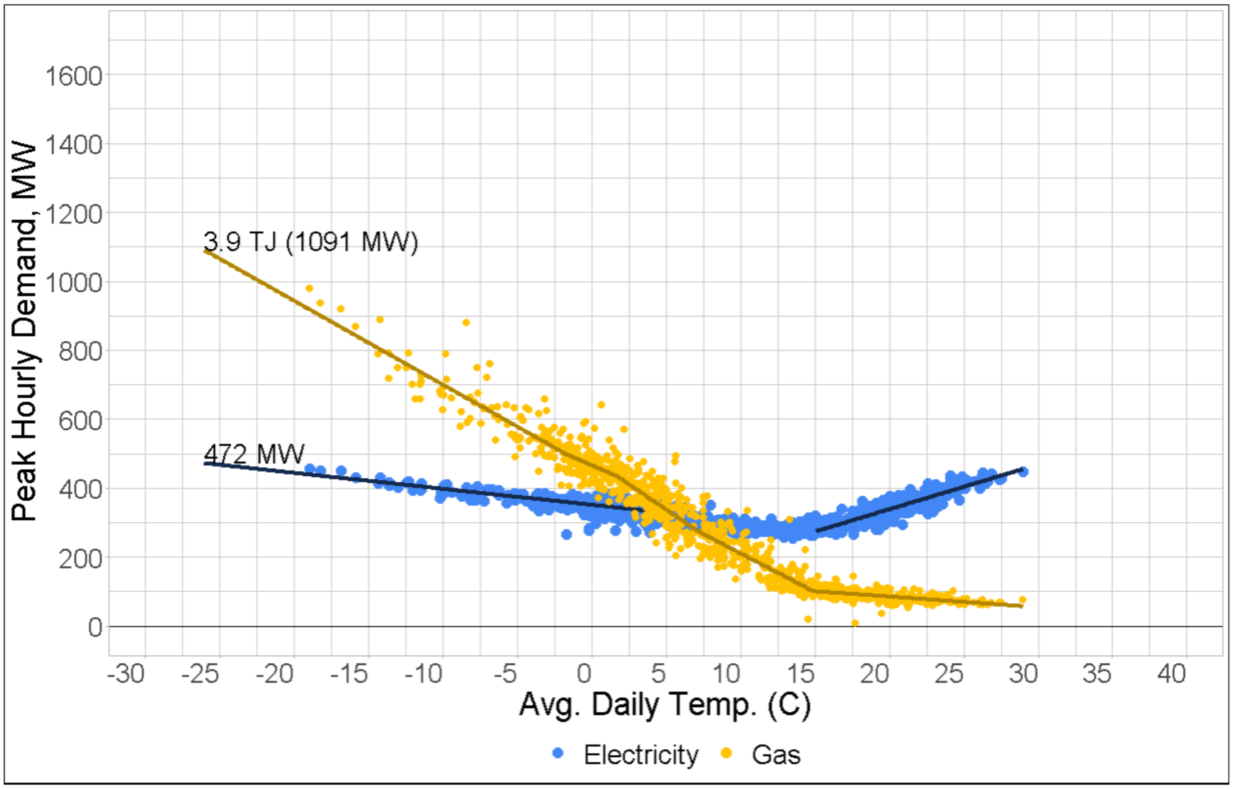
[14] With the exception of heat pumps being increased to the maximum efficiency setting in the 100 percent electrification case, as discussed in footnote 13.

[15] These results, as well as other scenarios for the City of Kelowna can be created through FortisBC's forecasting model. FortisBC can provide live demonstrations and discussions of the assumptions by request.

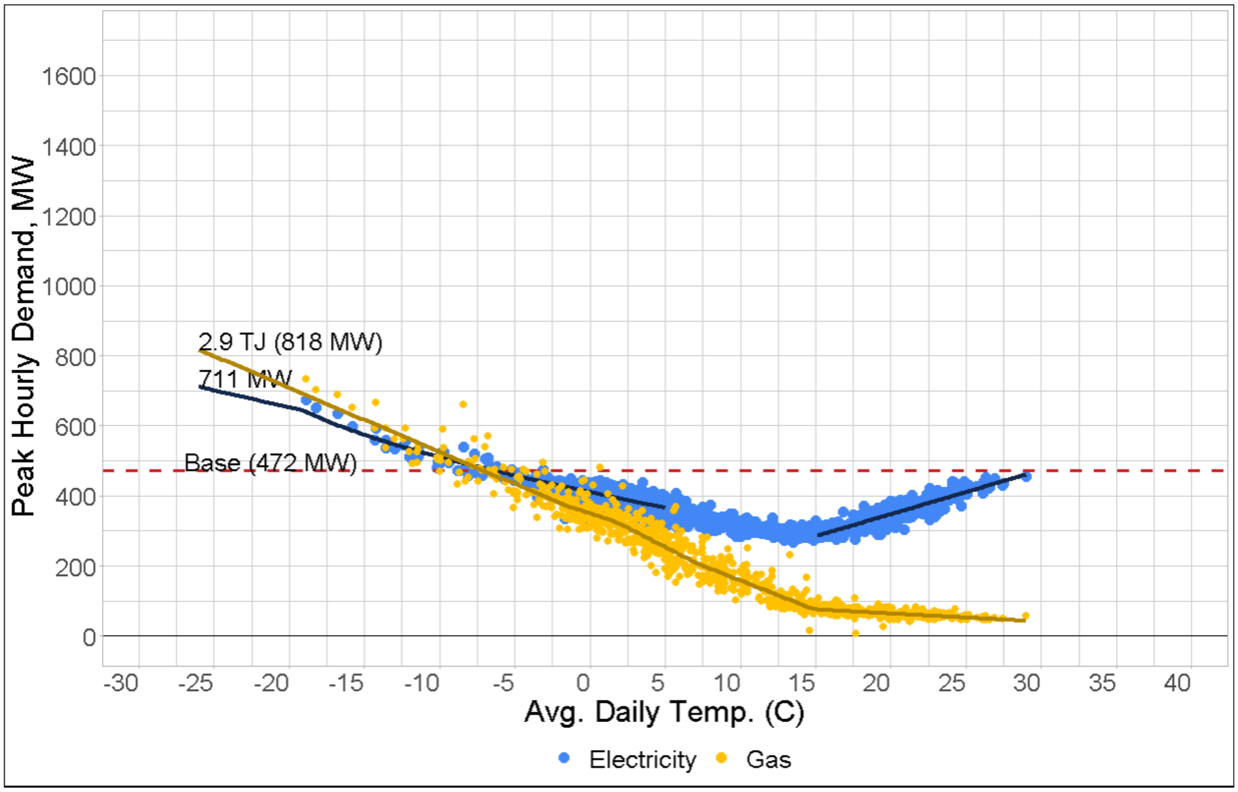
Figure 3-3: City of Kelowna - Electricity and Gas Demand by Temperature in 2040 with Zero Percent Electrification



3.4 *25 PERCENT INCREMENTAL ELECTRIFICATION OF GAS DEMAND CASE*

Figure 3-4 demonstrates that with the incremental electrification of gas demand increased to 25 percent by 2040, and all else equal, FortisBC's forecast demand of 711 MW in 2040 would be 51 percent over the forecast 472 MW peak winter demand at -26 C with zero percent electrification illustrated in Figure 3-3.

Figure 3-4: City of Kelowna - Electricity and Gas Demand by Temperature in 2040 with 25 Percent Electrification

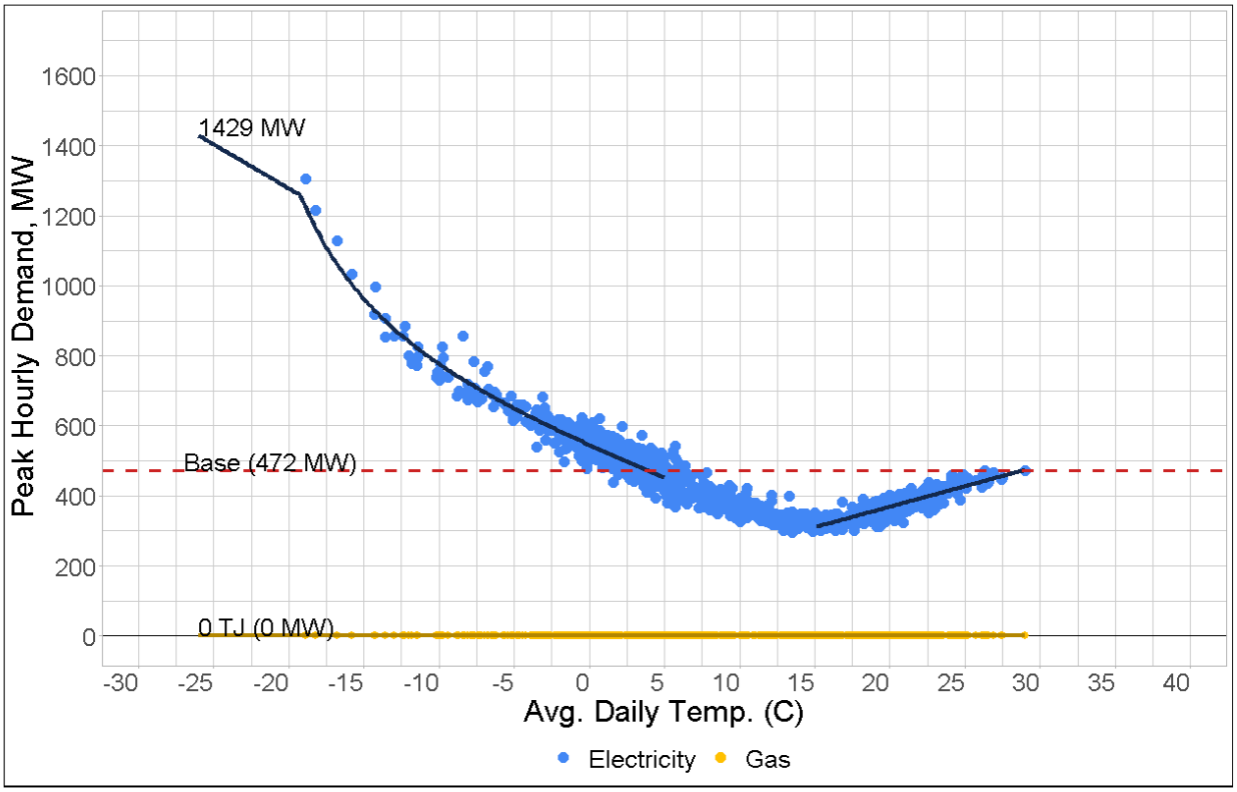


3.5 *100 PERCENT INCREMENTAL ELECTRIFICATION OF GAS DEMAND CASE*

Figure 3-5 illustrates how, with 100 percent electrification by 2040, and all else equal except increasing the efficiency of heat pumps[16], FortisBC's forecast demand increases from 711 MW in 2040 under 25 percent electrification to 1,429 MW under full electrification. While this timeline for electrification of gas demand is more aggressive than the Deep Electrification Scenario in the FEI 2022 LTGRP, this scale of electrification is challenging on any timeline, and insurmountable in the scenario timeline. The 1,429 MW of demand in 2040 is over three times higher than the forecast 472 MW peak winter demand illustrated in Figure 3-3 with zero percent electrification.

[16] Heat pump efficiencies used in this analysis are described in footnote 13, in Section 3.1 above.

Figure 3-5: City of Kelowna - Electricity and Gas Demand by Temperature in 2040 with 100 Percent Electrification[17]



4. INFRASTRUCTURE AND POWER SUPPLY REQUIREMENTS TO MEET PEAK DEMAND

For the purpose of the Study, FortisBC based potential system impacts and estimated upgrade costs for the City of Kelowna on the analysis produced for the 2021 LTERP, which examined the impacts of alternate future load scenarios. The results discussed in this section are high-level estimates and may change as more detailed analysis for each of the projects is conducted in the future. Costs identified in the Study to date have been developed internally and have not been assessed within the cost estimate classification system of the Association of Cost Engineering (AACE). The system upgrade estimates are based only on the peak demand, and do not consider the costs of peak and annual energy provided from generation resources within the Kelowna region, nor the benefits of localized generation in reducing the amount of required system upgrades. Sections 4.2 and 4.3 afterwards discusses a high-level estimate of the land acquisition and power supply costs required to serve the increased demand in Kelowna.

17 The non-linear shape of the fitted line is a result of applying COP values from heat pumps to base load data as temperatures decline.

4.1 *SYSTEM IMPACTS AND UPGRADE COSTS FOR INCREASED DEMAND IN KELOWNA*

To determine the system impacts from the individual scenario peak-demand forecasts, FortisBC used the following assumptions, aligned with those in the 2021 LTERP:[18]

- 100 percent of the new generation resources required to meet the added loaded would be from outside the Kelowna area via existing or new FBC-BC Hydro and Power Authority (BC Hydro) interconnections (to identify the transmission impacts without including generation within the Kelowna area);
- The existing generation resource dispatch (i.e. scheduling of output) will use the most recent typical peak winter and summer dispatch;
- Additional peak demand for each scenario has been proportionally allocated to the LEE 138 kV and DGB 138 kV busses in order to simplify the simulation models;
- Typical transmission planning criteria, as was provided in Section 6.2.2 of the 2021 LTERP, were applied;
- Project cost estimates do not include land acquisition costs. Land costs are discussed separately in Section 4.2;
- Kelowna distribution load continues to be served at 13 kV. Conversion of some or all distribution to 25 kV will likely need to be completed but the costs of this have not been incorporated in these estimates; and
- The estimates provided are in 2021 dollars.

FortisBC notes this simulation exercise was designed to provide a high-level illustration of the potential impacts on FBC's electric system and was not subject to the rigor of FBC's typical in-depth modelling process.[19] A more detailed estimate would also require more detailed inputs, such as a forecast providing the shape and location of load, as well as the location of generation resources and distribution assets. These more detailed demand and locational studies have not yet been completed. Therefore, the results presented here should not be interpreted as concrete plans for system changes, but more as indications of what system requirements might look like if various levels of electrification occur in the future.

The 2021 LTERP cost projections for currently planned projects are reproduced in Table 4-1[20] below. Table 4-1 indicates that currently planned projects to meet the 2021 LTERP peak demand forecast of 428 MW for the City of Kelowna will cost approximately $128 million, which is based on expected load growth without any incremental electrification beyond what is embedded in historical loads.[21]

[18] Section 6.5.4 of the 2021 LTERP.
[19] Such as full N-1 contingency studies.
[20] Table 6-5 in the 2021 LTERP.
[21] Table 6-6 in the 2021 LTERP illustrated the $710 million estimate for additional projects required to meet the peak demand forecast of 550 MW by 2040 for the City of Kelowna.

Table 4-1: Planned Projects (1 in 20 Peak Demand Forecast by 2040)

Project	Project Cost ($ Millions)
Static VAR Compensator (SVC)	30
DG Bell 230 kV Ring Bus	10
Kelowna Bulk Transformer Capacity Addition	21
Re-conductor 51L & 60L (DG Bell-OK Mission)	9
Ellison Second Distribution Transformer Addition	8
Benvoulin Second Transformer Addition	8
Saucier Second Distribution Transformer Addition	7
DG Bell 138 kV Breaker and Voltage Transformer Addition	1
DG Bell Second Distribution Transformer Addition	6
FA Lee Distribution Transformer Addition	8
Duck Lake Second Transformer Addition	6
Glenmore Third Transformer Addition	6
Hollywood Third Transformer Addition	8
Total	**128**

In Table 4-2 below, FortisBC applied the same assumptions and method used for the 2021 LTERP to estimate the projects required within the 20-year planning horizon in the Kelowna area to meet the peak demand levels from the 25 percent, 50 percent and 100 percent electrification cases shown in Table 3-2 above. As per the preliminary nature of this analysis and report, the projects and costs in this estimate were scaled and added as needed to meet the increasing amounts of incremental demand and were not done through a specific transmission or distribution planning study to determine the year requirement and specificity of the project. The cost for all the projects in Table 4-2 below are high-level indicative costs.

Table 4-2: Additional Projects[22] Required to Meet a Peak Demand of 25%, 50% and 100% Electrification Cases by 2040

Peak Demand and Electrification Cases	Project Costs ($ Millions)		
	711 MW (25%)	950 MW (50%)	1,429 MW (100%)
New Distribution Stations	120	180	300
New Distribution Feeders	80	120	200
Meshing Kelowna 138 kV Transmission System	20	20	20
138 kV Transmission Line Re-conductor	80	120	200
138 kV Transmission Line Addition	60	90	150
Ashton Creek to Vaseux Lake (ACK-VAS) 500 kV Transmission Line	500	500	500
DG Bell Second 230/138 kV Transformer Addition	20	20	20
Kelowna 230 kV Source (Line & Terminal Station)	50	50	50

[22] A new distribution station, distribution feeder, 138kV transmission line re-conductor, and 138kV transmission line addition was assumed to be required for every 200 MW of new load in the City of Kelowna.

Peak Demand and Electrification Cases	Project Costs ($ Millions)		
	711 MW (25%)	950 MW (50%)	1,429 MW (100%)
Additional Ashton Creek to Vaseux Lake (ACK-VAS) 500 kV Transmission Line (Station not Required)[23]	n/a	450	450
Total	**930**	**1,550**	**1,890**

Table 4-2 illustrates the escalation of electric system upgrade costs through cases of increasing amounts of incremental electrification of gas demand within the City of Kelowna. If peak demand in the Kelowna area surpasses 550 MW, the complexity of the system upgrades quickly moves beyond primarily modifications and transformer additions. The load level of 550 MW triggers the requirement for the Ashton Creek to Vaseux Lake 500 kV transmission line[24], and upon surpassing 950 MW, an additional 500 kV line is required, with an expected lead time of at least ten years. The approximately $1.9 billion of required additional projects under the 100 percent electrification case implies many operational, environmental and other permitting and system planning challenges, a major one of which is siting and acquisition of land rights and construction, which are further discussed in Appendix A.

The additional costs related to the electrification cases are significantly higher than for FBC's currently planned projects, which was $128 million in the 2021 LTERP as shown in Table 4-1. As a solution to meet the increased load, the additional projects identified above could be implemented, if required, through a significant amount of additional system planning, analysis and construction. However, mitigation strategies could be deployed to reduce a portion of these peak demand requirements, which are addressed in Section 4.4.

4.2 LAND ACQUISITION COSTS

FortisBC provides the following high-level discussion to illustrate the magnitude of the costs that could be incurred to acquire the land for the system upgrade projects provided in Table 4-2. As described at the outset of this section, the costs identified are preliminary, high-level numbers and are not considered AACE Class 5 level costs assessments or better. However, land cost information has been developed using actual land value data available for the general types of land expected to be involved in the types of projects discussed in Section 4.1. A range of costs was developed by estimating land area requirements based on similar projects and industry experience, identifying approximate size of land areas needed within expected types of land use areas, and using a range of publicly available land value data sources. The low end of the range is based on high-level estimates of land costs today, whereas the high end of the range represents the potential future increase in land values over the planning horizon. All land acquisition cost values provided are in 2021 dollars.

[23] These estimated costs do not include any upgrades to BC Hydro's system in order to accommodate this project, of which FBC would be expected to provide a contribution based on the principles of cost causation.
[24] Estimated to be approximately 160km long with a tap near Kelowna for a new 500/230 kV substation.

Table 4-3: Range of Current and Future Estimated Land Acquisition Costs Required to Meet a Peak Demand of 25%, 50% and 100% Electrification Cases by 2040

Peak Demand and Electrification Cases	Project Cost Ranges ($ Millions)		
	711 MW (25%)	950 MW (50%)	1,429 MW (100%)
Total Land Acquisition and right-of-way costs for projects identified in Section 4.1	345 – 776	605 – 1,361	680 – 1,531

Although these are early and high-level estimates, the results demonstrate that the land requirements for completing the projects needed to meet various levels of electrification of gas load within the City of Kelowna are potentially nearly as much as the costs of the infrastructure projects themselves. The land acquisition estimates were derived using land parcels outside of Agricultural Land Reserve (ALR) areas; however, given the North Okanagan area lies largely within ALR areas, this may result in increased timelines and costs to acquire the land. Further, successfully acquiring land tenures and constructing the necessary infrastructure will require the support of Indigenous nations impacted by the projects; however, the costs of securing support have not been included as they are not easily quantified. General challenges associated with development of these projects and the need to acquire land or rights-of-way are also discussed at a high-level in Appendix A.

4.3 *LONG-TERM POWER SUPPLY IMPLICATIONS*

In the context of long-term planning, FBC develops load forecasts for different purposes for system and power supply planning.[25] To ensure that FBC's network infrastructure is sufficient to provide a safe and reliable electricity supply to all customers, the transmission and distribution system must be planned, constructed, and operated to meet peak load requirements during extreme weather conditions or the "1 in 20-year" forecast[26]. In contrast, FBC's "Reference Case" load forecast is used to plan generation resources needed to meet energy and peak demand requirements under normal or average (not design) weather conditions and evaluated for planning reserve margin using a Loss of Load Expectation (LOLE) criteria[27]. In the context of the Study, the discussion below is provided based on the peak demand under cold temperatures in the City of Kelowna and, under such significant load impacts, FBC would need to re-evaluate the practice of planning to normal weather conditions as well as the current planning reserve margin criteria used to assess the risk of loss of load events.

The estimates contained in Section 4.1 have been prepared assuming that all incremental power needed to meet the winter peak is sourced from resources outside of the FBC system and delivered to the points of interconnection between FBC and BC Hydro. Assuming that sufficient BC Hydro transmission is constructed and available, the cost of power from BC Hydro will at a minimum be the capacity cost from the power purchase agreement (PPA) with BC Hydro (set out

[25] A system planning forecast "1 in 20-year" for transmission and distribution infrastructure planning as well as a capacity and energy resource planning forecast or "Reference Case".

[26] Load Forecasting for System Planning, Section 6.3.1 of Exhibit B-1 of the FBC 2021 LTERP Proceeding, page 125.

[27] Appendix M (Planning Reserve Margin Report) of the 2021 LTERP.

in Rate Schedule 3808), which is $103,860/MW-year as of the 2021 LTERP.[28] However, this is the lowest reasonable estimate available and an optimistic, bookend value for meeting the peak demand needs in the electrification cases for the City of Kelowna.

FBC preferred portfolio C3 (clean resource portfolio with renewable natural gas (RNG)-fueled generation) from the 2021 LTERP contains some capacity generation resources that are assumed to be located in the Kelowna region, namely two RNG-SCGT (simple-cycle gas turbine) units and a 25 MW utility-scale battery. These resources would provide a combined 173 MW of dependable winter capacity at an estimated cost of approximately $350 million[29] which is exclusive of land acquisition costs. Locating generation in the Kelowna area would reduce a portion of the peak demand on the transmission system, thereby potentially deferring some transmission requirements and providing locational value.[30]

The power supply requirements are based only on the capacity resources to meet the single peak day and do not include the cost of energy. The challenge of ensuring that sufficient capacity is available is compounded through the nature of cold snaps, which generally last multiple days and shift the entire daily load curve upward, thereby creating a much higher energy requirement. The need for large volumes of energy in several consecutive hours, or even days, is a challenge for capacity resources such as batteries that store energy rather than generate energy, as the storage capabilities (duration) becomes the limiting factor of operation given the need to recharge.[31] The challenge in building intermittent electric resources to adequately provide capacity during cold winter periods are discussed in further detail in Appendix A. In further studies analyzing the impacts of deep electrification to FBC's energy load, the roles of energy storage verses energy generation would warrant greater consideration as resources capable of storing energy would need a recharge cycle during the cold snap.

4.4 *SUMMARY OF SYSTEM IMPACTS*

In the short-term, amounts of increased load through electrification would be expected to have a favourable impact on electric rates initially, as long as there is surplus capacity available from existing generation resources and transmission and distribution infrastructure. However, the Study demonstrates that for an area such as Kelowna that does not have substantial remaining system capacity, greater amounts of electrification can rapidly translate into infrastructure investments and higher capital costs. A summary of the cost estimates for the Kelowna electrification cases ranging from $1.3 billion to $3.4 billion is provided below in Table 4-4.

[28] BC Hydro Electric Tariff: Rate Schedule 3808 – Transmission Service – FortisBC Inc, page 5-73. The demand charge is $8.655 per kW of Billing Demand per Billing Month in 2021 dollars as of the 2021 LTERP. $8.655 * 1000 * 12 months = $103,860/MW-year (or $104/kW-year).

[29] Approximate cost of the RNG SCGT generators and corresponding interconnections to FBC's system. Excludes ongoing operating and maintenance costs as well as any upgrades to FBC's system beyond the point of interconnection. Furthermore, these costs also do not include any upgrade on the FEI's gas system to support a 148 MW SCGT plant as described in Section 7.3.3.5 of the FEI 2022 LTGRP.

[30] FortisBC response to RCIA IR1 25.1 (Exhibit B-8 of the FBC 2021 LTERP) and BCUC IR2.54 series (Exhibit B-11 of the FBC 2021 LTERP).

[31] FortisBC response to CEC IR1 44.1 (Exhibit B-9 of the FBC 2021 LTERP).

Table 4-4: Summary of System Impacts and Land Acquisition Costs Required for Electrification Cases by 2040[32]

	Project Costs ($ Millions)		
Peak Demand and Electrification Cases	**711 MW (25%)**	**950 MW (50%)**	**1,429 MW (100%)**
System Upgrades (Table 4-2)	930	1,550	1,890
Land Acquisition (Table 4-3)	345 – 776	605 – 1,361	680 – 1,531
Total	**1,275 - 1,706**	**2,155 - 2,911**	**2,570 - 3,421**

To mitigate some of the above costs, instead of building or upgrading infrastructure, FBC would pursue and deploy measures including siting localized generation, EV charging shifting, and demand response. However, as noted in Section 4.3, the local generation as outlined in the 2021 LTERP would reduce the peak demand by only 173 MW. Shifting 50 percent of the EV charging would reduce the peak demand impacts by 38 MW (of the 75 MW outlined in Table 3-1), and demand response and curtailment and load shifting programs would be expected to only reduce a small portion compared to the 1,429 MW required under the 100 percent electrification case. The program costs to support any demand side mitigation measures are not included in this report. Lastly, greater observed efficiencies of heat pumps under colder temperatures and further technology and performance improvements would also help to reduce the peak load impacts.

To fully reduce the system infrastructure requirements from the 1,429 MW to the 711 MW level would remove the need for the second 500 kV line ($450 million) and associated land (estimated to be between $208 and $467 million), but the capital cost to provide the 718 MW from localized generation along with additional capacity from BC Hydro would cost at a minimum $350 million and $44 million in annual power purchase expense[33]. These results demonstrate that the full cost and peak load impacts of electrification need to be more clearly understood, warranting caution on electrification initiatives and highlighting the need for further bottom-up analysis. Additionally, it is vital to consider the impact that this would have on remaining FEI gas customers through any transition or fuel switching to FBC electricity customers.

5. RESILIENCY CONSIDERATIONS

As a final, high-level note on the implications of a deep or an accelerated electrification future for BC that have not yet been fully explored, simply shifting energy delivery from the gas system to the electricity system would also cause a critical loss of overall energy system resiliency. In general, gas transmission and distribution systems experience significantly fewer outages than electric networks[34]. The vast majority of electric transmission and distribution in North America

[32] The expenditures associated with power supply purchases or new resource additions are not provided as they are not directly additive, do not include the cost of energy, and would reduce a portion of the system upgrade and land acquisition costs.

[33] $350 million for 173 MW of capacity resources in Kelowna in addition to $44 million annually for 545 MW of capacity from BC Hydro. $44 million is calculated as 545 MW * $8,655/MW/Month for December and 409 MW (75% of Billing Demand) for the remaining 11 months of the year. This does not include the cost of RNG to supply the two SCGT units.

[34] Industry surveys and studies conducted by the US Gas Technology Institute have demonstrated gas customer average reliability/availability levels (due to unplanned causes) of 0.9999978. (Gas Technology Institute, Topical

(including with FBC) is via overhead power lines, which are more exposed to disruptive events including lightning, wind, ice, impacts from trees and third-party contacts. Consequently, electric power lines have considerably higher outage rates than underground gas lines. Most gas outages are typically localized incidents that result from third-party damage to gas system infrastructure.

Based on industry experience, on average, a typical 80 km overhead electric transmission circuit is expected to experience one unplanned outage event per year[35]. Since circuit outages are an expected occurrence in electric networks, asset redundancy is commonly employed to ensure compliance with minimum standards of reliability. The BC Mandatory Reliability Standards (MRS) require that the bulk electric system be planned and operated to withstand an unexpected outage of the single most critical system element, coincident with the forecast system peak load, while not experiencing any firm customer outages[36]. This is referred to as the N-1 reliability criterion and is based on North American industry standards. These industry standards were developed and mandated following two major northeastern US and Canada blackouts, one in 1965 and one in 2003. In other words, the cost of this necessary system redundancy is broadly accepted by electric operators and regulators in order to ensure adequate levels of customer service. While the high-level costs and considerations identified in this report do include the electricity system N-1 planning criteria, this criteria does not supplant the inherent resiliency offered by the combined electric and gas systems throughout BC.

In contrast to the outage expectations for overhead electric transmission, large-diameter, high-pressure pipelines may operate for long periods without experiencing any unplanned outage events. To FortisBC's knowledge, there are no specified regulatory requirements for gas system reliability anywhere in North America equivalent to the electric utility N-1 criterion. However, in interconnected gas networks with numerous supply points interspersed with multiple delivery points, a reliable network is a consequential outcome. Thus, in many areas of North America, the redundancy afforded by multiple gas supplies, storage, and transportation paths results in an inherently resilient system. This is also true in the Okanagan region of the FEI system where multiple geographically-diverse gas transmission line interconnections with upstream providers exist.

On average, the outage expectations discussed above would suggest that a typical natural gas customer in BC would expect 69 seconds of service outage per year,[37] compared to approximately 2.4 hours per year for a typical FBC electric customer (even with the high standards of redundancy

Report (July 19, 2018) "Assessment of Natural Gas and Electric Distribution Service Reliability," p. 10.) This is consistent with the service availability levels of the Canadian Gas Association when comparing outage incidents. In contrast, the comparable average availability for most electric customers in BC is approximately 0.99959. In other words, on average the gas system is 186 times more reliable than the electric system.

[35] North American Electric Reliability Corporation (NERC). "Outage Metrics, 2019 WECC AC Circuit." Total Circuit Outage Frequency of 1.97 per 100 mi·yr (for 200-299kV circuits). https://www.nerc.com/pa/RAPA/tads/Pages/OutageMetrics.aspx

[36] BCUC Order R-27-18 (June 28, 2018). "British Columbia Hydro and Power Authority Mandatory Reliability Standard TPL-001-4 Assessment Report." P. 8, Attachment D.

[37] Gas Technology Institute, Topical Report (July 19, 2018), "Assessment of Natural Gas and Electric Distribution Service Reliability." Online: https://www.gti.energy/wp-content/uploads/2018/11/Assessment-of-Natural-Gas-Electric-Distribution-Service-Reliability-TopicalReport-Jul2018.pdf

on the electric system).[38] In practice, the vast majority of FEI's customers have never experienced a single natural gas outage, other than for planned reasons such as a meter exchange.

Energy supply disruptions during extremely cold weather could have significant customer impacts and result in serious societal harm, as was experienced in the state of Texas during the February 2021 winter storm.[39] The need for resilience is even greater as energy supply on both gas and electric systems shifts to incorporate intermittent sources. However, the gas and electric systems can complement each other providing greater overall energy system resiliency. Meeting peak thermal requirements and providing resiliency and reliability from the gas system is essential for moderating electric peak load growth and ensuring an overall smoother low-carbon transition for BC's energy consumers.

6. SUMMARY AND CONCLUSIONS

The results of the Study illustrate the impacts of electrification of gas demand that, at the coldest temperatures, could more than triple the electricity demand in the City of Kelowna from 472 MW to 1,429 MW in 20 years. This amount of peak demand for the City of Kelowna alone is significant, given that FBC's entire electric service territory system peak load record is 835 MW, set in December 2022. This Study illustrates the challenges regarding the scale of a full electrification scenario. With full electrification, it is estimated that expenditures of between $2.6 and $3.4 billion will be required for system upgrades and associated land to transmit and distribute energy to serve FBC's expected electric load growth, handle incremental EV charging, along with the addition of fuel-switching of 43,850 gas customers by 2040. For comparison purposes, FBC's total rate base was approximately $1.7 billion for 2023.[40] This cost estimate does not include the total power supply requirement cost on both an annual and peak basis for what would be required to meet the increased demand for Kelowna. The associated system upgrade expenditures would likely result in cost increases for FBC's electricity customers, however, capital costs could also be partially mitigated by deployment of non-wires solutions such as EV load shifting and demand response.

FortisBC is in a unique position to use the City of Kelowna as a case study to demonstrate the impacts of electrification on peak demand and system upgrade costs, illustrating at a high-level the challenges associated with meeting winter heating demand through one energy system. The examination of the Kelowna Electrification Case Study demonstrates that the transfer of peak demand from the gas system to the electric system creates a significant requirement for additional electric infrastructure and associated land to address the incremental winter electric peak demand. This Study provides a starting point for further analysis to understand the holistic impacts of electrification, including the current state of the electric system's ability to accommodate electrified load, as well as in other regions that include a higher number of

[38] FBC recorded a 2022 year-end normalized SAIDI of 2.42 for its transmission and distribution system.

[39] https://www.dallasnews.com/news/weather/2021/04/30/number-of-texas-deaths-linked-to-winter-storm-grows-to-151-including-23-in-dallas-fort-worth-area/.

[40] FBC approved rate base of $1,675 million included in FBC 2023 Annual Review of Rates application approved by the BCUC per Order G-382-22 dated December 22, 2022.

customers as well as a lower load factor (i.e. higher weighting to winter heating demand), highlighting the importance of collaboration and coordination between the gas and electric systems in the province.

Further bottom-up analysis on electrification could include specificity regarding energy and capacity resources to meet higher demand, energy conservation, additional localized generation, analysis of various-end use conversions, and analysis of the benefits of load shifting or rate mitigation. Therefore, further work is required in the future to more closely consider the shifting of substantial energy use throughout the province, the combined gas and electric rate and bill impact to BC energy consumers, the total costs and implementation risks of electrification, as well as the benefits that may be achieved through other pathways to decarbonization. The Kelowna Electrification Case Study illustrates the need to further examine the tools to moderate peak energy demand and leverage the gas and electric systems to work together to support a practical, resilient, and more affordable pathway to lower GHG emissions in the province.

Appendix A

CHALLENGES FOR THE ELECTRIC SYSTEM IN BRITISH COLUMBIA TO SERVE A DEEP ELECTRIFICATION PATHWAY

APPENDIX A: CHALLENGES FOR THE ELECTRIC SYSTEM IN BRITISH COLUMBIA TO SERVE A DEEP ELECTRIFICATION PATHWAY

1. INTRODUCTION

The Kelowna Electrification Case Study (the Study) provides an examination of the scale and scope of electric system resources required to serve the Kelowna area under even partial electrification of gas demand. The Study itself does not, however, discuss all of the challenges involved with designing, siting, building and commissioning the needed resources, irrespective of the high costs identified in the Study. The purpose of this Appendix is to:

- Demonstrate a number of the practical challenges being experienced and expected in planning and implementing energy infrastructure through the next 10 to 20 years that need to be considered; and
- Show that these challenges make the Deep Electrification Scenario[1] in Kelowna (and, by extension, throughout the FortisBC electric service territory) implausible within the time frame required to meet the Province's carbon reduction targets, and even moderate levels of electrification challenging.

FortisBC, in delivering both natural gas (through FortisBC Energy Inc. or FEI) and electricity (through FortisBC Inc. or FBC), has extensive experience in transmitting and distributing energy to customers throughout British Columbia. FortisBC leverages its experience and industry expertise to provide local (and regional when not available) examples of technical and logistical challenges in building the supporting infrastructure required in the timeframe for a deep electrification energy pathway in BC.[2] These challenges can be categorized as follows:

- Execution and feasibility for shifting demand and ensuring adequate supply (Section 2);
- Acquiring land for new infrastructure (Section 3);
- Obtaining necessary project permits, approvals, and consent (Section 4);
- Constructing transmission and distribution projects (Section 5); and
- Transitioning customers to electricity (Section 6).

A deep electrification pathway to a decarbonized energy future within the time frame required to meet government emission reduction target timelines would require an immense and rapid electric system build-out. Real examples within FortisBC's service territory of the challenges of building

[1] In the 2022 LTGRP, the Deep Electrification Scenario is one in which electrification is the primary avenue utilized by the BC Government to decarbonize the BC economy and it assumes reliance on only one main source of supply. In this scenario, it is assumed that 100 percent of residential and commercial demand and 20 percent of industrial demand for gas is switched to electricity by 2050.

[2] The "Zero" scenario in David Suzuki Foundation's "Shifting Powers" report uses baseline load growth published from Canadian utilities, while the "Zero Plus" scenario explores greater levels of electrification in buildings, transportation and industrial sectors, as well as giving greater priority to energy efficiency and building retrofit options.

energy infrastructure are used throughout this Appendix to illustrate the obstacles that must be overcome to support the pursuit of this pathway in BC.

This Appendix provides an initial examination of the challenges to building out the electric system to handle the increase in load that would be caused by entirely or substantially shifting current and future gas use in BC to electricity. It is not intended to be exhaustive, nor is it meant to suggest that any one or even a number of these challenges cannot be overcome. Considered as a whole across numerous and diverse projects, however, these issues can be expected to delay or confound efforts to decarbonize through electrification, and potentially put the electricity generation, transmission and delivery system at risk if electrification proceeds while infrastructure development is delayed. Together, these issues and the high infrastructure costs presented in the Study, result in an implausible scenario for shifting demand and supporting infrastructure development in the envisioned time frame.

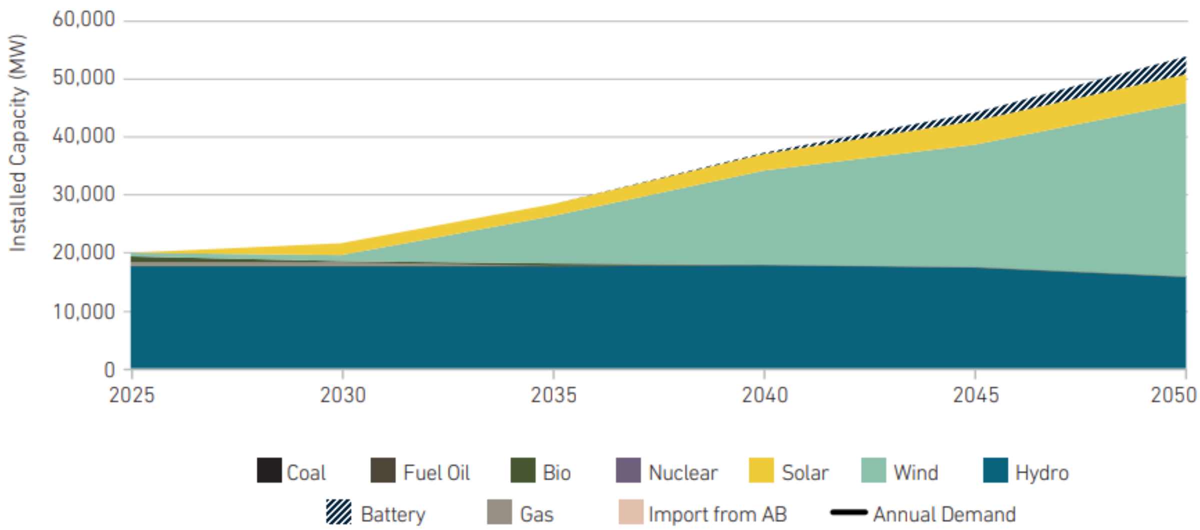
2. EXECUTION AND FEASIBILITY FOR SHIFTING DEMAND AND ENSURING ADEQUATE SUPPLY

Deep electrification entails conversion of gas demand into load (or load and plausible energy savings) on the electric system, and conversion of peak building heating load from gas to electricity. Transitioning peak building heating load creates especially challenging capacity requirements, as the gas and electric systems experience winter peak demand during the same, or very similar, times in BC. In order to provide the incremental energy requirements of this new demand on the electric system and ensure adequate capacity is available to meet the peak load, significant greenfield generation resources would be required.

The impact of electrification on BC's generation requirements has been studied by independent, third parties. For example, according to the David Suzuki Foundation, the amount of capacity resources required under a high electrification scenario (Zero Plus)[3] could theoretically result in a near tripling of generation resource needs for BC by 2050, as shown below in Figure A-1. These results on a province-wide basis for BC are similar to the 100 percent incremental electrification of gas demand case in Kelowna, which tripled the peak demand forecast in 2040 from 472 MW to 1,429 MW as was shown in Section 3.5 of the Study.

[3] The "Zero" scenario in David Suzuki Foundation's "Shifting Power" report uses baseline load growth published from Canadian utilities, while the "Zero Plus" scenario explores greater levels of electrification in buildings, transportation and industrial sectors, as well as giving greater priority to energy efficiency and building retrofit options.

Figure A-1: British Columbia Electricity Capacity Mix (MW) for Zero Plus scenario[4]



Building generation capacity requires planning, siting, project approval, supply procurement and construction. Depending on the resource type, a generation project may require long lead times before it is in-service and generating power.

Generating electricity to support peak demand requirements with carbon-free resources has its own set of challenges. Carbon-free generation will likely involve a proportionally uncertain mix of intermittent renewable resources, batteries, hydrogen technologies, and demand response or mitigation measures. As intermittent resources, such as wind and solar, do not always produce power during the times that they are needed, utilities will also have to ensure that there is firm dispatchable generation to reliably supply electricity.[5] This includes ensuring that there is adequately planned resources for both peak heating events in the winter and peak cooling events in the summer, which may require substantial development of energy storage resources (e.g. utility-scale batteries, pumped storage) in order to meet these needs, and analysis of the cost impacts from those resource decisions.[6]

Utilities relying on significant proportions of intermittent renewable generation results in different considerations that have not been experienced with conventional integrated utility distribution. If distributed energy sources were to become more prevalent, it is not well understood if the BC electric system could effectively manage the associated flexibility needs of the system, including the need for flexibility in power (i.e., ramping), and transfer capacity (i.e. grid bottle necks).[7] As

[4] David Suzuki Foundation, "Shifting Power - Zero-Emissions Electricity Across Canada by 2035" (May, 2022): https://davidsuzuki.wpenginepowered.com/wp-content/uploads/2022/05/Shifting-Power-Zero-Emissions-Across-Canada-By-2035-Report.pdf

[5] IHS Markit, "New Configurations: Americas gas and power in net zero" (August, 2022).

[6] Palmer-Wilson, Rowe, Wild, "Cost and capacity requirements of electrification or renewable gas transition options that decarbonize building heating in Metro Vancouver, British Columbia" (May, 2021): https://www.sciencedirect.com/science/article/pii/S2211467X22000803.

[7] Impram, Varbak Nese, Oral, "Challenges of renewable energy penetration on power system flexibility: A survey" (September, 2020): https://www.sciencedirect.com/science/article/pii/S2211467X20300924.

another example, distributed rooftop solar 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 distributed generation growth continues.[8] With respect to system planning, it will be vital for electric utilities to understand what occurs when the electric system takes on growing distributed generation and substantial amounts of dynamic loads from end-uses like heating and vehicle charging with additional daily, seasonal and extreme weather-driven peaking requirements. Additionally, and depending on customer uptake and successful program and rate design, developing scaled and effective demand response programs for heating, electric vehicle charging, and other end-uses like industrial load would need to become part of the solution to avoid peak capacity requirements, as opposed to construction of infrastructure. These solutions will take time to develop and refine. Other considerations relevant to meeting demand requirements with new generation resources are described in the following sections.

3. ACQUIRING LAND FOR NEW INFRASTRUCTURE

Acquiring the land required for new generation, transmission or distribution infrastructure is becoming more challenging due to increased public opposition to new infrastructure. There are many competing pressures for the limited remaining undeveloped and redevelopment lands for siting infrastructure. Transmission and distribution infrastructure is often inflexible in its siting due to the need to efficiently transmit electricity from its generation source to specific demand centres, while avoiding environmentally sensitive areas or areas where strong public opposition exists. While public opinion toward renewable energy is generally positive, public perception can turn negative, even among those generally in favour of renewable energy, when, for example, people believe that a renewable infrastructure development will cause them economic or health problems, or when they dislike the aesthetics of the project.[9]

In the United States, challenges regarding the build out of the American power grid are occurring in town halls, county courthouses and community buildings across the country.[10] In order for clean energy goals to be achieved, rural communities, which have large tracts of land necessary for commercial wind and solar farms, need to be persuaded to embrace renewable energy projects. But with greater amounts of renewable energy projects under construction around the US, resistance is growing, especially in rural communities, due to the amount of additional land required. This opposition can result in land acquisition challenges and project uncertainty, delays and incremental costs in the development of new renewable resources and supporting infrastructure. Lastly, as urban development continues, there becomes less land available for further infrastructure projects, so that conflicts between competing land uses including energy infrastructure will arise more frequently.

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8 BCUC 2022 Generic Cost of Capital proceeding, FBC Stage 1 Evidence, Appendix B, page 26.
9 Brookings, "Renewables, Land Use, and Local Opposition in the United States" (January, 2020), page 9.
10 The New York Times, "A Town-by-Town Battle to Sell Americans on Renewable Energy" (December, 2022).

Two examples of land acquisition challenges relating to electricity infrastructure projects to serve FBC's customers are:

- FBC is currently in the process of acquiring land for the relocation and upgrade of the Fruitvale substation. FBC's preferred location faced public opposition and FBC has not yet been able to secure the land for the substation. Construction was scheduled to begin in 2024. FBC is continuing to work with the community and related parties regarding the relocation; and
- The FBC Trout Creek substation upgrade project took over six months longer than was expected on account of delays in the land acquisition process, which took over one year to complete. This project had both Agricultural Land Reserve (ALR) and private landowner challenges, which delayed the process for acquiring the land.

These examples illustrate that public opposition to land acquisitions may result in delays in developing new infrastructure in the province. Considering the number of land acquisitions, the routing that will be required in limited available paths and corridors, and the space that would be required to support a deep electrification scenario, it follows that these delays would be highly prevalent and impactful. Developing the needed infrastructure to support a deep electrification pathway may be challenging simply due to limited remaining space and land available in municipalities and regions to locate transmission and distribution lines and other necessary assets.

4. PERMITTING, PROJECT APPROVALS AND CONSENT

Certificates of Public Convenience and Necessity (CPCN) from the BCUC and numerous other approvals from various agencies and organizations at the federal, provincial, Indigenous community and municipal levels must be obtained before any infrastructure project can proceed. Each project will have its own unique requirements, and in many cases, these permitting requirements can halt projects entirely or significantly extend their timelines.

In the BCUC's 2022 Generic Cost of Capital (GCOC) Proceeding, FortisBC identified a number of more recent developments that have impacted project planning and approval timelines. These include enhanced Indigenous engagement, the requirement to obtain approval through more robust parallel processes to the BCUC's process, specifically the environmental assessment (EA) process, increased complexity around municipal requirements and more general stakeholder engagement and consultation. Each of these areas is discussed below.

With the introduction of the *United Nations Declaration on the Rights of Indigenous Peoples Act* and the need for proponents to seek free, prior and informed consent, there is a realization of a greater need for early engagement with Indigenous Nations to proceed with energy infrastructure projects in BC, the progress of which can depend on the availability and institutional capacity of the Indigenous groups. For instance, FEI started engagement with the Penticton Indian Band (PIB) in June 2019 on the Okanagan Capacity Upgrade (OCU) project. In February of 2022, the BCUC adjourned the regulatory review process for that project to facilitate further engagement between FEI and PIB. One year later, negotiations continue and the proceeding has not been restarted. To ensure continued supply of gas to its customers in that region, FEI is has been developing interim measures to address the capacity shortfall resulting from the delay to approval of the OCU project that has resulted.

Large energy infrastructure projects, including electricity transmission projects, may require an EA in accordance with the *BC Environmental Assessment Act* (BCEAA) and/or the *Federal Impact Assessment Act* (IAA) which govern the preliminary approval process for British Columbia and Canada, respectively. The process under the BCEAA includes seven steps that consist of the early engagement, planning, assessment, review, approval, and follow-up recommendation, and Ministerial Decision. The early engagement prior to preparation of the initial project description commonly takes 10 to 18 months and application preparation timelines are typically 12 to 24 months. The review process itself is anticipated to take 570 days, however, there are provisions that allow for the extension of the timeline. Similar to the BCEAA, the IAA has a focus on early planning and engagement as well as increasing opportunities for Indigenous peoples to participate in the assessment process.

In addition to the EA approval process (when required), there will be numerous environmental and technical risks associated with requiring a multitude of projects. Projects will include development in urban, rural and natural areas with potential environmental impacts on watercourses, sensitive ecosystems (including riparian areas), at risk species, agricultural areas, and archaeological sites. FortisBC anticipates that there would be significant regulatory triggers under the *Fisheries Act*, *Species at Risk Act*, *Water Sustainability Act*, *Environmental Management Act*, and *Heritage Conservation Act*. Due to the myriad of federal and provincial regulatory requirements, a regulatory permitting strategy will be required to manage potential design related regulatory risks. From a scheduling perspective, FortisBC expects that an individual project would require up to one year for baseline field studies, preparation of regulatory filings and a further 8 to 16 months for application, review and approval of applicable permits. Baseline data collection is subject to seasonal limitations and typically occurs between mid-May and late September of any given year.

Regarding municipal permits, a significant amount of new electric infrastructure would need to be built within city limits to support both continued traditional electric load growth and new load due to electrification. Municipalities will have concerns about the impact of new substation and power line infrastructure on future development plans, future expansion of other public works and aesthetics. Until these concerns are addressed, it is unlikely that a permit can be obtained for a project to proceed.

Overall, in FortisBC's experience, there is greater interest in project activities, greater lead time required to conduct consultation and engagement work, and an increasing number of platforms available to the public and local residents to raise concerns to elected officials, regulators and utilities on projects. Project costs and timelines will continue to expand as consultation and engagement expectations continue to grow. Even projects which, on their face, might have been expected to be more "routine", are now subject to a broader range of considerations and, therefore, extended regulatory processes. Failure to reach agreements and gain consent in any one of these areas can mean that projects are not just delayed, but ultimately not constructed.

5. CONSTRUCTING TRANSMISSION & DISTRIBUTION PROJECTS

A deep electrification scenario will require substantial infrastructure build out, and likely include inter-jurisdictional transmission projects to utilize different resources more cost-effectively between regions with different peaking requirements, which would necessitate significant coordination and collaboration between many political and private entities. Challenges in developing needed infrastructure are being experienced in BC and throughout the Pacific Northwest (PNW).

In BC, there have been no new large transmission projects constructed in more than seven years; however, the British Columbia Transmission Corporation's (BCTC) Interior to Lower Mainland (ILM) Transmission Project provides the most recent example of the challenges that can be expected in this province. The CPCN for this 247-kilometre, 500 kilovolt (kV) transmission line project was filed with the BCUC in November 2007.[11] Consultation with stakeholders began in 2006[12] and project construction activities commenced in 2012, with the new line being placed into service in December 2015. This indicates a project timeline of at least nine years when project development is included. The initial project cost was estimated at $602 million but, upon completion, final costs were $828 million. Some of the cited reasons for cost and time overruns include failure to properly consult with First Nations, issues with the construction contractor, access to private land and identification and handling of archaeology sites.[13] For timelines to construct planned (future) transmission upgrades in BC, BC Hydro has identified a 10-year lead time requirement for their South Coast upgrades, with BC Hydro stating that "the 10-year lead time for each of the steps in the transmission upgrades is based on available information considering factors such as historical information pertaining to similar projects and input from subject matter experts."[14]

These issues are not unique to BC. Utilities across the Pacific Northwest (PNW) face similar challenges to other regions in terms of building out new renewable projects: supply chain constraints, logistics around procurement, public opposition, as well as interconnection and transmission challenges.[15] To illustrate, electric utilities in the US PNW are failing to build infrastructure fast enough to keep up with state electrification policy.[16] Oregon and Washington have some of the strongest climate plans and policies in the country, including measures that require electric utilities to shift to solar and wind for their power generation. However, the region's transmission system cannot support the energy load. Lastly, to bring the comparison to BC, a

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[11] BC Hydro website https://www.bchydro.com/energy-in-bc/projects/sunset/ilm/info_centre.html#proj_updates.
[12] Exhibit B-1 of the BC Hydro Application for a CPCN for the Interior to Lower Mainland Transmission Project.
[13] Vancouver Sun "Vaughn Palmer: Hydro 'shocker' isn't the first time project wires got crossed" (May, 2018): https://vancouversun.com/opinion/columnists/vaughn-palmer-hydro-shocker-isnt-the-first-time-project-wires-got-crossed.
[14] BC Hydro response to CEBC IR 1.19.1 (Exhibit B-10 of the BC Hydro 2021 IRP).
[15] Utility Dive, "Pacific Northwest plan calls for 3.5 GW of renewables, more energy efficiency by 2027" (June, 2022): https://www.utilitydive.com/news/pacific-northwest-plan-3500-mw-of-renewables-2027-energy-efficiency.
[16] Sightline Institute, "Northwest States Need to Build New Power Lines, Fast" (October, 2022): https://www.sightline.org/2022/10/13/northwest-states-need-to-build-new-power-lines-fast/.

10-year lead time may not necessarily be representative of any future greenfield transmission project in the province, as developing transmission projects can sometimes take nearly 20 years as evidenced in the US Pacific Northwest.[17]

Procurement issues can also impact project timelines and costs. The increased reliance globally on critical minerals required for electricity infrastructure may cause an imbalance in the demand and supply for those minerals, which could in turn affect supply chains for these materials, causing delays and increasing costs in building electric infrastructure. Other growing procurement challenges include general mine productivity as well as the ability to meet the need for environmentally sound sources of materials considering resource extraction, production and acquisition. Additional general examples of supply chain challenges include labour cost pressures, inflation, political instability, water issues, resource nationalism and access to capital.[18]

These global procurement issues are impacting FortisBC's resource requirements and operations at a local scale, which has been demonstrated by the difficulty in procuring the necessary goods and materials required to complete projects on time and on budget. Since the onset of the COVID-19 pandemic, supply chain issues have increased the delivery times and costs for major equipment. For example, a circuit breaker replacement project at FBC's Okanagan Mission substation was planned for 2022 execution but needed to be deferred to 2023 due to a delivery delay. Expected deliveries for substation high-voltage breakers are currently 12 to 14 months as compared to approximately 6 months in 2019. Likewise, typical substation transformer delivery times have increased from 8 to 10 months to 18 to 24 months, and large substation transformers may now have delivery times in excess of 30 months, causing delays in capital activities for transmission, distribution and substation assets.

In general, the constructability of transmission and distribution infrastructure is becoming more difficult and procurement challenges are increasingly impacting project timelines. New large-scale projects in the province will face increasing challenges to be built which will increase the costs and timeframe required to support a deep electrification pathway.

6. TRANSITIONING CUSTOMERS TO ELECTRICITY

Deep electrification will require household and commercial building energy system retrofits, the volume of which will contribute to long waits for goods and serves required to transition gas customers to electricity. Rewiring America, a non-profit that conducts research and advocacy on electrification, estimates that 60 to 70 percent of single-family homes in the US will need to upgrade to a bigger or more modern electrical panel to accommodate a fully electrified home, and the need for qualified technicians can delay intended customer transitions.[19]

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[17] Sightline Institute, "Northwest States Need to Build New Power Lines, Fast" (October, 2022): https://www.sightline.org/2022/10/13/northwest-states-need-to-build-new-power-lines-fast/.

[18] Mining technology, "The tipping point: large scale challenges for the mining industry" (April, 2021): https://www.mining-technology.com/features/the-tipping-point-large-scale-challenges-for-the-mining-industry/.

[19] Grist, "To get off fossil fuels, America is going to need a lot more electricians" (January, 2023): https://grist.org/energy/electrician-shortage-electrify-everything-climate-infrastructure-labor/.

The BC Government's CleanBC plan is aimed at significantly reducing BC's greenhouse gas (GHG) emissions by 2050, including meeting sectoral targets for 'buildings and communities' by 2030. Achieving the target GHG emissions reduction by 2030 implies that 60 percent of residential and commercial space and water heating transitions to electricity with electric heat pumps and other appliances by 2030, at a rate of 7 percent per year or approximately 57,000 houses per year.[20] The expected useful life of residential furnaces and water heaters is approximately 18 years and 13 years, respectively, which means that maximum end of life replacements rates are 5.6 percent per year for furnaces and 7.7 percent per year for water heaters. As such, some households would have to replace their furnaces before the end of their expected useful life to meet the 7 percent target. This becomes even more challenging to achieve the desired scale of retrofits when coupled with projections of increasing BC's housing supply by 53,000 to 117,000 units per year to 2030.[21] To put these numbers into context, within BC, collectively, between retrofits and new builds, only approximately 2,500 new heat pumps were installed in the residential sector each year from 2017 to 2019, which indicates a starting point or low-end for heat pump installation rates.[22]

Some of the many challenges in meeting this electric installation and conversion transition for residential units include lack of available contractors for heat pump installations, appliance supply, skills shortages and supply-chain challenges.[23] Retrofits in apartments or other buildings with multiple units can also have structural challenges or envelope change requirements to accommodate different types of heat pumps and indoor and outdoor units. According to the BC Building Electrification Road Map,[24] there are several barriers to electrification of existing buildings and new construction, particularly in rural communities. These include:

- Relatively high initial capital costs;
- Electrification retrofits often require additional planning and time compared to like-for-like replacements;
- Limited technology options in some equipment categories;
- Lack of awareness both among consumers and industry (including contractors);
- Lack of trained contractors and professionals available to meet the potential increase in demand;

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[20] BCUC Energy Scenarios for BC Hydro and FEI, BCUC requesting information regarding BC Hydro and FEI Energy Scenarios.
[21] Canada Mortgage and Housing Corporation (CMHC), "Canada's Housing Supply Shortage: Restoring affordability by 2030" (June, 2022). The higher range is estimated for what would be required for affordability to be restored in BC.
[22] CER, "Market Snapshot: Steady growth for heat pump technology". Natural Resources Canada - Comprehensive Energy Use Database – Table 21.
[23] OPEN Technologies and Vancity, "Stuck: Why home electrification is lagging in British Columbia and what must be done to break the deadlock on residential carbon retrofits" (June, 2022).
[24] Zero Emissions Building Exchange, "BC Building Electrification Road Map" (March, 2021): https://www.zebx.org/wp-content/uploads/2021/04/BC-Building-Electrification-Road-Map-Final-Apr2021.pdf.

- Potential legal challenges for commercial buildings trying to leave long term service agreements with district energy providers; and
- In rural communities, there could be challenges related to shipping, limited ability to purchase and install new technology, and limited access to repair and maintenance. Additionally, colder climate zones and rural areas which may experience more frequent outages may need to rely on back up and/or peak load space heating options.

On the customer side of infrastructure, the desired scale of retrofits and electric appliance installations required to meet provincial GHG emission reduction targets would result in an electric heat pump installation rate significantly higher than achieved in recent years. This transition for customers must also consider the high costs and logistics of upgrading electrical systems and changing out energy appliances downstream of customer meters in a fair and equitable manner to all energy ratepayers and taxpayers in BC.

7. CONCLUSION

A deep electrification pathway will require significant capital investments across multiple parts of the electricity sector value chain, and coordination between provinces and governments may layer on additional complexity. While decarbonization is one important objective, it is also important to consider affordability, as well as resiliency to customers; ensuring reliable energy infrastructure through coordinated resource planning and managing system reliability during times of increasingly extreme weather events. As regions have diminishing levels of flexible generation and increasingly have supply mixes that are more heavily weighted to variable resource profiles needed for a Deep Electrification Scenario, the risk of energy shortfalls and potential risks that could impact the long-term reliability and resiliency of the electric system need to be fully considered and addressed. Utilization of the existing and planned investment in gas infrastructure throughout the Province is vital to help overcome these challenges and provide a higher likelihood of safely reaching carbon reduction goals.

Each of the preceding sections discuss and provide examples of the increasing technical and logistical challenges in building out supporting infrastructure that would be required for a deep electrification future within BC. These challenges in BC are also reflected in other jurisdictions by the simultaneous pursuit of decarbonization through electrification for many utilities throughout North America. Landowner concerns and public opposition to projects, even renewable ones, can result in land acquisition challenges and project uncertainty, delays and incremental costs in the development of new renewable resources and the required supporting infrastructure. Even once land is acquired, the constructability of transmission infrastructure is becoming more difficult and increasing regulatory requirements can impact project development. Consulting with Indigenous communities and impacted stakeholders has also increased in complexity and scope which also increases the lead times required for projects and, in some cases, increases project uncertainty. Constrained labour markets, supply chain challenges and global demand for energy system materials can delay or jeopardize needed electricity infrastructure projects required for a Deep Electrification Scenario. Building mechanical upgrades and retrofit / rebuild requirements will challenge the feasibility of executing such an energy transition at the rate of implementation needed to meet Provincial carbon emission reduction targets. Developing a plan to rapidly address and mitigate all of the above challenges and activities must also avoid foreclosure of opportunities for more efficient, lower cost pathways to decarbonization that either exist today for some applications or may emerge as broadly applicable as technology advances.[25]

In summary, all of these considerations are expected to add years and costs to each individual project timeline and increase project implementation uncertainty. The significant number of projects that would be required to enable a deep electrification future increases the complexity of such activities, rendering such a future scenario implausible within the time frame required to achieve Provincial emission reduction targets through electrification alone.

[25] Rapson, Bushnell, "The Electric Ceiling: Limits and Costs of Full Electrification" (October, 2022): https://haas.berkeley.edu/wp-content/uploads/WP332.pdf.

Appendix B

50 AND 75 PERCENT INCREMENTAL ELECTRIFICATION OF GAS DEMAND CASES

APPENDIX B: 50 AND 75 PERCENT INCREMENTAL ELECTRIFICATION OF GAS DEMAND CASES

This Appendix includes the results of the 50 and 75 percent incremental electrification of gas demand cases to supplement the zero percent, 25 percent, and 100 percent cases in the Kelowna Electrification Case Study.

Figure B-1 below shows the results of the 50 percent incremental electrification of gas demand case. The figure demonstrates that with the incremental electrification of gas demand increased to 25 percent by 2040, and all else equal, FortisBC's forecast demand of 950 MW in 2040 would be approximately 100 percent over the forecast 472 MW peak winter demand at -26 C with zero percent electrification illustrated in Figure 3-3 of the Kelowna Electrification Case Study.

Figure B-1: City of Kelowna - Electricity and Gas Demand by Temperature in 2040 with 50 Percent Electrification

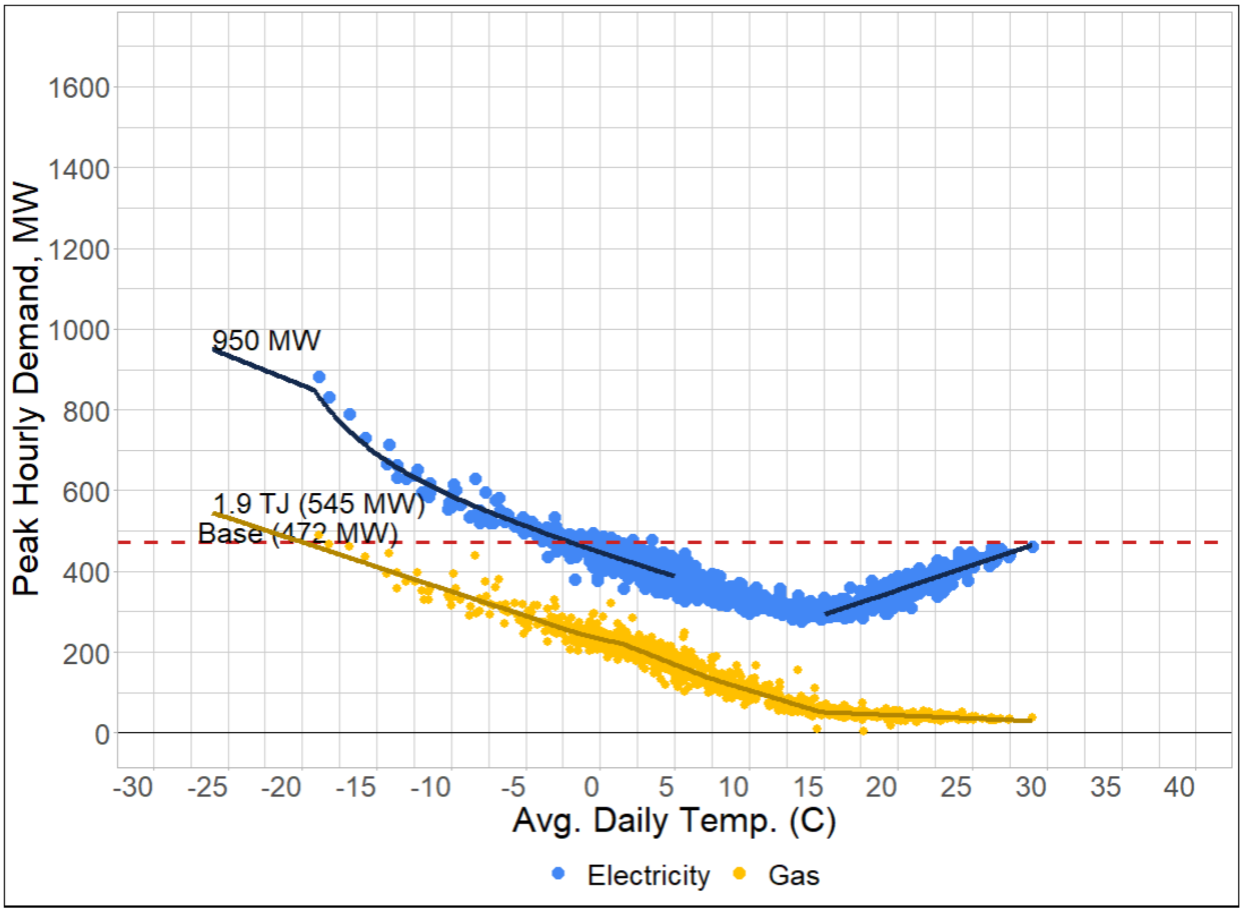

Figure B-2 below shows the results of the 75 percent incremental electrification of gas demand case. The figure demonstrates that with the incremental electrification of gas demand increased to 75 percent by 2040, and all else equal, FortisBC's forecast demand of 1,190 MW in 2040 would be 152 percent over the forecast 472 MW peak winter demand at -26 C with zero percent electrification illustrated in Figure 3-3 of the Kelowna Electrification Case Study.

Figure B-2: City of Kelowna - Electricity and Gas Demand by Temperature in 2040 with 75 Percent Electrification