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July 14, 2023

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Energy Inc. (FEI)

Application for a Certificate of Public Convenience and Necessity (CPCN) for the Okanagan Capacity Upgrade (OCU) Project (Application) ~ Project No. 1599152

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1 on Supplementary Filing

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On November 16, 2020, FEI filed the Application referenced above. In accordance with BCUC Order G-106-23 establishing a further regulatory timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1 on Supplementary Filing.

FEI requests that a portion of the responses to BCUC Supplementary IR1 16.9, 22.1, and 22.2, which are redacted in the public version, be filed on a confidential basis, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-72-23 for the reasons described below.

- Response to BCUC Supplementary IR1 16.9 - The confidential information is commercially sensitive information that should remain confidential in perpetuity because, if disclosed, may prejudice negotiations with other parties in the future.

- Responses to BCUC Supplementary IR1 22.1 and 22.2 – The confidential information is commercially sensitive information that cannot be disclosed under the terms of an agreement between FEI and the Penticton Indian Band with respect to their negotiations. Further, the confidential information should remain confidential in perpetuity as disclosure may harm or prejudice negotiations with other parties in the future.

The confidential responses are being filed with the BCUC under separate cover and will be made available to registered parties with signed Confidentiality Declarations and Undertakings filed on the record in this proceeding.

For convenience and efficiency, if FEI has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FEI intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

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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A. PROJECT NEED AND JUSTIFICATION

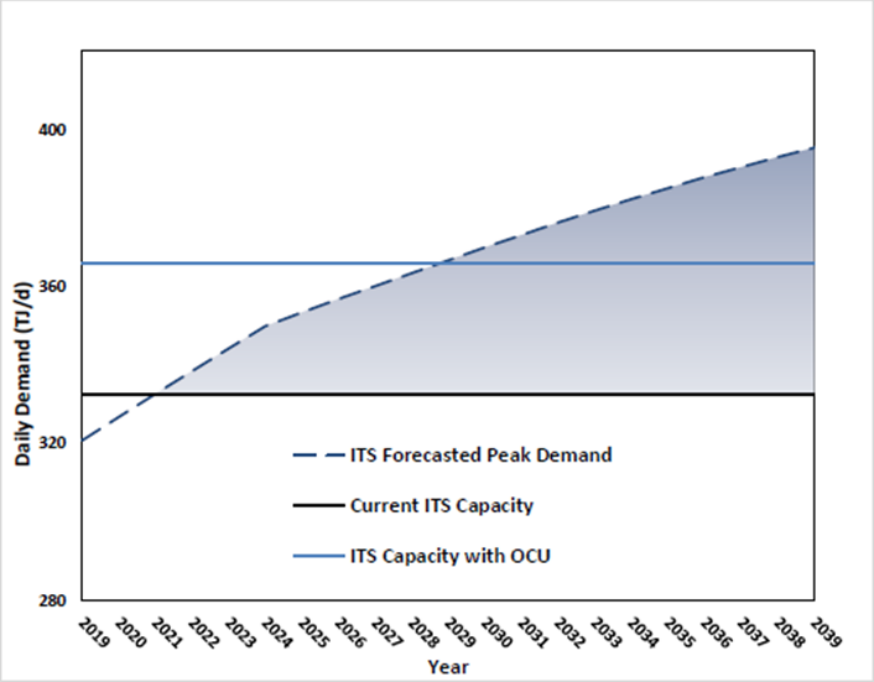
1.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1-2 (Updated Application), Section 3.3.1, p. 20; Exhibit 1-2-1, Appendix L-1, L- 2, L-3; Exhibit B-35 (Supplementary Filing), Section 2.1, p. 3, Section 2.2, pp. 4-5

2022 Peak Demand Forecast

On page 20 of the Updated Application, FortisBC Energy Inc. (FEI) provides a graph of the Interior Transmission System (ITS) Peak Demand vs. Capacity After Completion of the Okanagan Capacity Upgrade (OCU) Project and the calculation of the forecast peak day demand.

Figure 3-8: ITS Peak Demand vs. Capacity After Completion of OCU Project



$$Peak\ Day\ Demand_{(Year\ N)} = \sum_{i=1}^{3} (\sum \text{Current Accounts} \times UPC_{peak} + \sum \text{Forecasted Accounts to Year N} \times UPC_{peak})_{(rate\ schedule\ i)} + \sum \text{Industrial Customer Maximum Demand} + \sum \text{Contract Obligations for Interruptible Customers}$$

In Appendix L, FEI provides BC Stats Forecast, Conference Board of Canada (CBOC) Housing Starts for BC, and ITS account and peak demand forecast details by rate schedules in Excel sheet format.

On page 3 of the Supplementary Filing, FEI states:

FEI updates the peak demand forecast on an annual basis. Accordingly, FEI's current peak demand forecast differs from the one provided in the Updated Application. When comparing the Supplementary Filing Forecast to the forecast used in the Updated Application, FEI observes that gas demand is still expected to increase, but at a lower rate. The Supplementary Filing Forecast confirms an imminent capacity shortfall.

The Supplementary Filing Forecast represents FEI's current available forecast information. The Supplementary Filing Forecast consists of the 2022 Forecast but incorporates the 2022 peak demand from core customers, which is calculated based on actual 2022 year-end core customer attachment and consumption data. […]

On page 4-5 of the Supplementary Filing, FEI presents two graphs showing the change in peak demand forecast.

Figure 2-1: Supplementary Filing Peak Demand Forecast

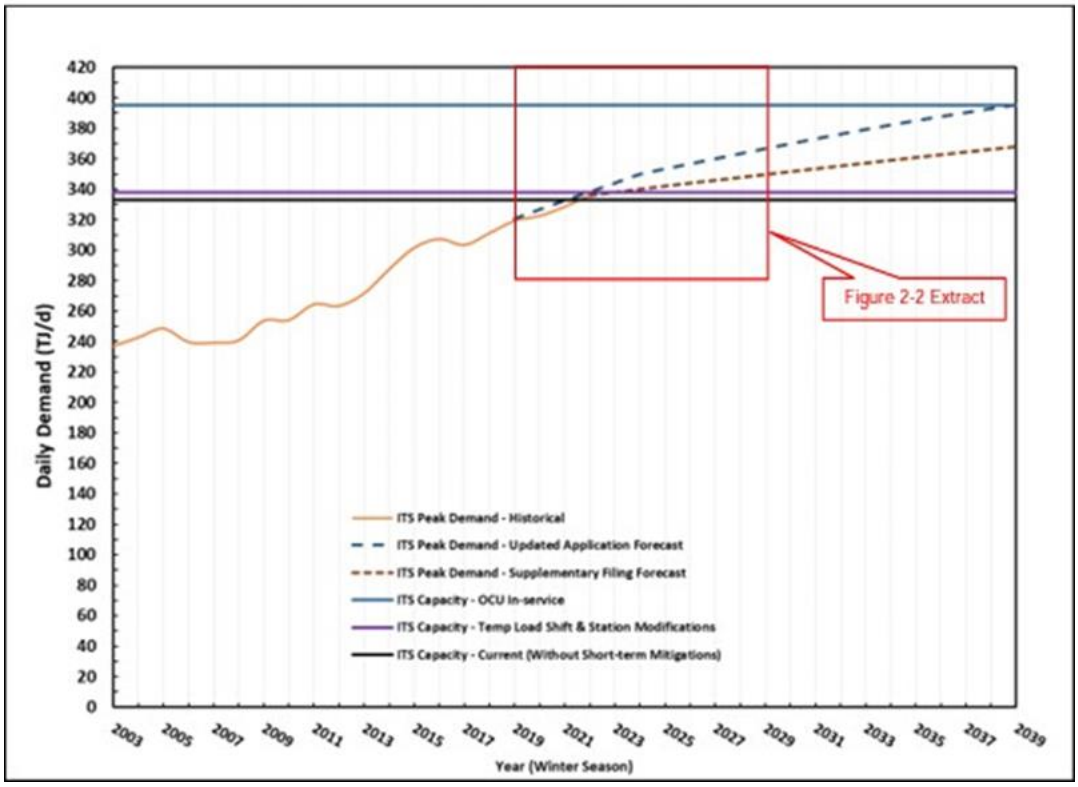
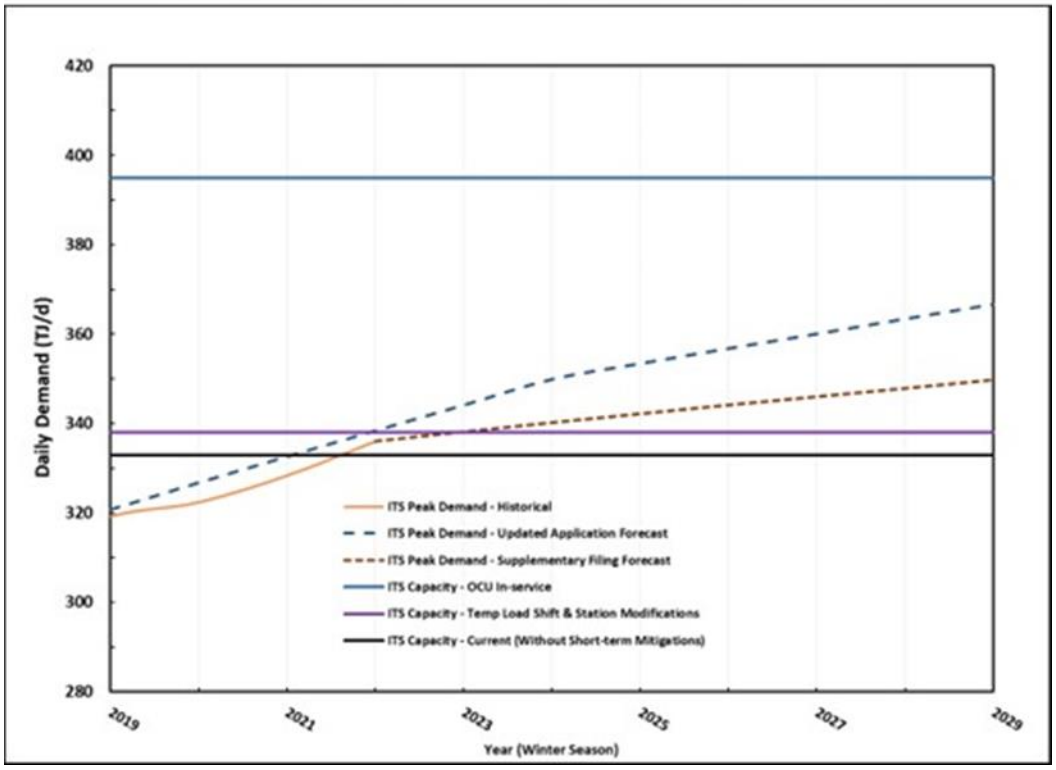


Figure 2-2: Extract from Supplementary Filing Peak Demand Forecast



Additionally, on pages 5 and 6 of the Supplementary Filing, FEI states:

> The historical peak demand for the ITS, titled "ITS Peak Demand – Historical", can be seen in Figures 2-1 and 2-2 above. The curve represents the calculated peak demand based on actual customer attachment and load data. FEI updated the curve in 2023 based on the actual 2022 core customer data. The curve shows the imminent need for the OCU Project, noting that the 2022 historical peak demand exceeds the current ITS capacity. [emphasis added]
>
> Figures 2-1 and 2-2 above also show that demand is forecast to exceed the ITS capacity with short-term mitigation measures in place, resulting in an expected capacity shortfall. With the temporary load shifting and station modification measures in place, a capacity shortfall is expected this winter (i.e., Winter 2023-24), as shown by the intersection of the Supplementary Filing Forecast line and the line titled "ITS Capacity – Temp Load Shift & Station Modifications". [emphasis added]

1.1 Please confirm, or explain otherwise, that the 2022 peak demand forecast methodology in the Supplementary Filing is consistent with 2019 peak demand forecast methodology in the Updated Application.

Response:

FEI observes that there may be confusion as to the basis of the various forecasts referenced in the proceeding (i.e., the Updated Application, Supplementary Filing and IR responses). Given the number of forecasts presented during this proceeding and the varying terminology being used, FEI provides the following table clarifying the terminology and basis of the different forecasts.

Forecast Name	Description	Basis	
		Customer Account Forecast	Year-End Actual Customer Data
ITS Peak Demand - Updated Application Forecast Or "Updated Application Forecast"	Peak demand forecast provided in the Updated Application. Equivalent to FEI's 2019 Peak Demand Forecast.	2019	2018
"2022 Peak Demand Forecast"	FEI's annual peak demand forecast provided in response to BCUC IR2 103.1 in the FEI 2022 Long Term Gas Resource Plan (LTGRP) proceeding.	2022	2021
ITS Peak Demand – Supplementary Filing Forecast Or "Supplementary Filing Forecast"	Peak demand forecast provided in the Supplementary Filing. Based on FEI's 2022 Peak Demand Forecast (i.e., the forecast provided in response to BCUC IR2 103.1 in the LTGRP proceeding), with base value adjusted using actual 2022 year-end core customer information.	2022	2022 (core customers[1])

As explained in the above table, the Updated Application Forecast is based on the 2019 Peak Demand Forecast. The Supplementary Filing Forecast is based on the 2022 Peak Demand Forecast provided in the response to BCUC IR2 103.1 in the LTGRP, with an adjustment which is explained in more detail below to account for 2022 actual core customer data. FEI confirms that the methods used for developing the Supplementary Filing Forecast and the Updated Application Forecast are fundamentally the same.

The forecasts used in the Updated Application and the Supplementary Filing were prepared based on the most up to date information available at the time of the respective filings. Peak demand forecasts are prepared annually and are generally completed by the end of Q3 of any given year. The Updated Application includes the 2019 Peak Demand Forecast which was based on actual 2018 year-end customer data and the 2019 forecast of customer growth. As noted in Section 2.1 of the Supplementary Filing, the Supplementary Filing Forecast provided in Figures

[1] RS 1, 2, 3 and 23.

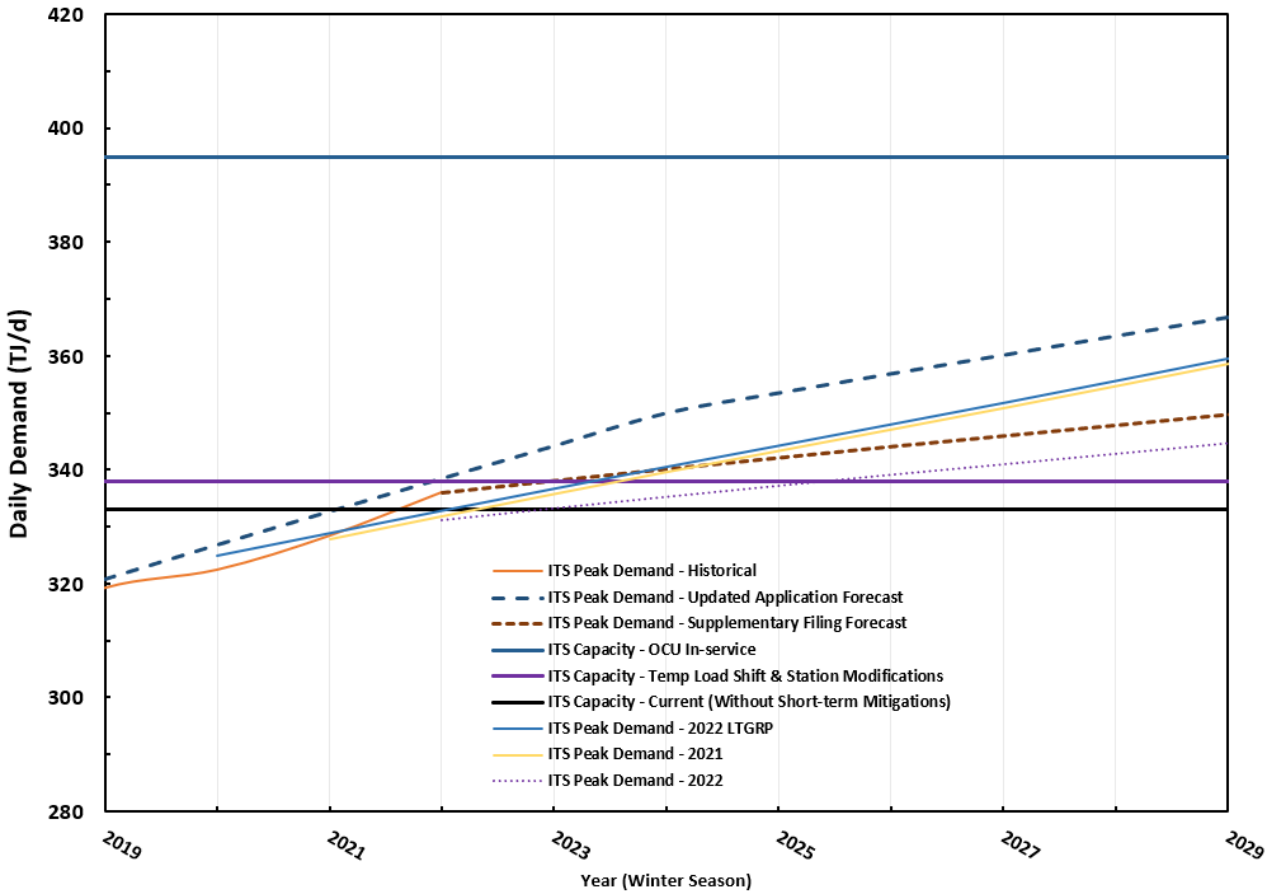
2-1 and 2-2 is based on the 2022 forecast of growth, but includes actual 2022 year-end core customer data that was available at the time of the Supplementary Filing.

In Figure 1 below, FEI provides an updated version of Figure 2-2 from the Supplementary Filing that overlays the forecast information provided in the response to BCUC IR2 103.1 in the 2022 LTGRP with Figure 2-1 from the Supplementary Filing to illustrate the different forecasts produced between the Updated Application and the Supplementary Filing.

As shown in Figure 1 below, and as referenced in Section 2.1 of the Supplementary Filing, the Supplementary Filing Forecast (brown dashed line) has the same rate of growth as the 2022 Peak Demand Forecast (purple dotted line). As further noted in Section 2.1, unlike the 2022 Peak Demand Forecast, the Supplementary Filing Forecast's starting point was adjusted upwards to match the 2022 year-end core customer data that was available at the time of filing, representing an increase of approximately 5 TJ/day.

FEI's rationale for adjusting the Supplementary Filing Forecast upwards was that without adjustment, the starting point of the forecast would not be reasonable given the actual circumstances. Specifically, if FEI were to rely on the unadjusted 2022 Peak Demand Forecast, the starting point of the forecast would be less than the Historic Peak Demand in 2022 which is based on actual year-end core customer data.

Figure 1: Updated Figure 2-2 from Supplementary Filing



As seen in the above figure and discussed in the responses to the BCUC IR2 103 series in the 2022 LTGRP, annual variations in the forecasted rate of growth of customer peak demand are often observed between forecasts. However, in all forecast scenarios there continues to be an expectation of growth in demand with the difference in the scenario forecasts being the rate of growth. Therefore, considering that 2022 peak demand has exceeded current ITS capacity (without short term mitigation), all scenarios, including the Supplementary Filing Forecast, support FEI's expectation that there is an immediate need for additional capacity, which is critical to maintaining service to existing and new customers throughout the ITS during periods of peak demand.

1.2 Please provide a comparison between the ITS peak demand forecast of the Updated Application and Supplementary Filing in a table format.

Response:

The following table compares the ITS peak demand forecast provided in the Updated Application to the ITS peak demand forecast provided in the Supplementary Filing.

Table 1: ITS Peak Demand Forecast (TJ/day)

Year	Updated Application	Supplementary Filing
2019	321	
2020	327	
2021	333	
2022	338	336
2023	344	338
2024	350	340
2025	353	342
2026	357	344
2027	360	346
2028	363	348
2029	367	350
2030	370	352
2031	373	353
2032	376	355
2033	379	357
2034	382	359
2035	385	361
2036	388	363
2037	390	364
2038	393	366
2039	395	368

1.3 Please explain in detail the drivers behind the lower rate of the 2022 peak demand forecast in the Supplementary Filing compared to the peak demand forecast in the Updated Application.

1.3.1 In the discussion, please also explain and quantify the main contributor(s) to the lower peak demand (e.g., customer account additions, peak use per customer (UPCpeak), industrial customer maximum demand, or contractual obligations for interruptible customers).

Response:

The primary driver of the difference between the growth rates of the peak demand forecasts provided in the Updated Application and the Supplementary Filing is differences in the customer account forecasts used in the two peak demand forecasts.

In response to BCUC IR2 103.1.1 in the 2022 LTGRP proceeding, FEI noted:

> FEI updates the traditional load forecast for each system annually and each year's changes in the long-term forecast, either upwards or downwards, are observed. The changes in the forecast are primarily the result of changes in two parameters:
>
> 1. UPC_{peak}, or peak use per customer values that are refreshed each year based on FEI customers' most recent consumption data; and
> 2. New customer account forecasts that revise the estimates of residential, small commercial and large commercial additions over the next 20 years.

As FEI demonstrates in the response to BCUC Supplementary IR1 3.3, UPC_{peak} values for 2019-2022 are not a significant contributor to the differences in the forecasts. UPC_{peak} values for RS 1 and RS 2 increased by 1.4 percent and 0.2 percent, respectively, between 2019 and 2022. The UPC_{peak} for RS 3 decreased by 0.7 percent through the same period.

Figure 1 below is an update to Figure 1 provided in response to BCUC IR1 6.5 (updated with actual RS 3 customer additions/subtractions from 2019 to 2022 for the ITS). The figure shows the unusually high number of RS 3 customer account additions that occurred through 2016, 2017 and 2018. These values were a key input for the 2019 customer account forecast which was used in the development of the Updated Application Forecast. In comparison, the values for 2019, 2020 and 2021 were used in the development of the 2022 Peak Demand Forecast, and as discussed in the response to BCUC Supplementary IR1 1.1, its growth rate is equivalent to that of the Supplementary Filing Forecast.

Figure 1: Updated Figure 1 from BCUC IR1 6.5

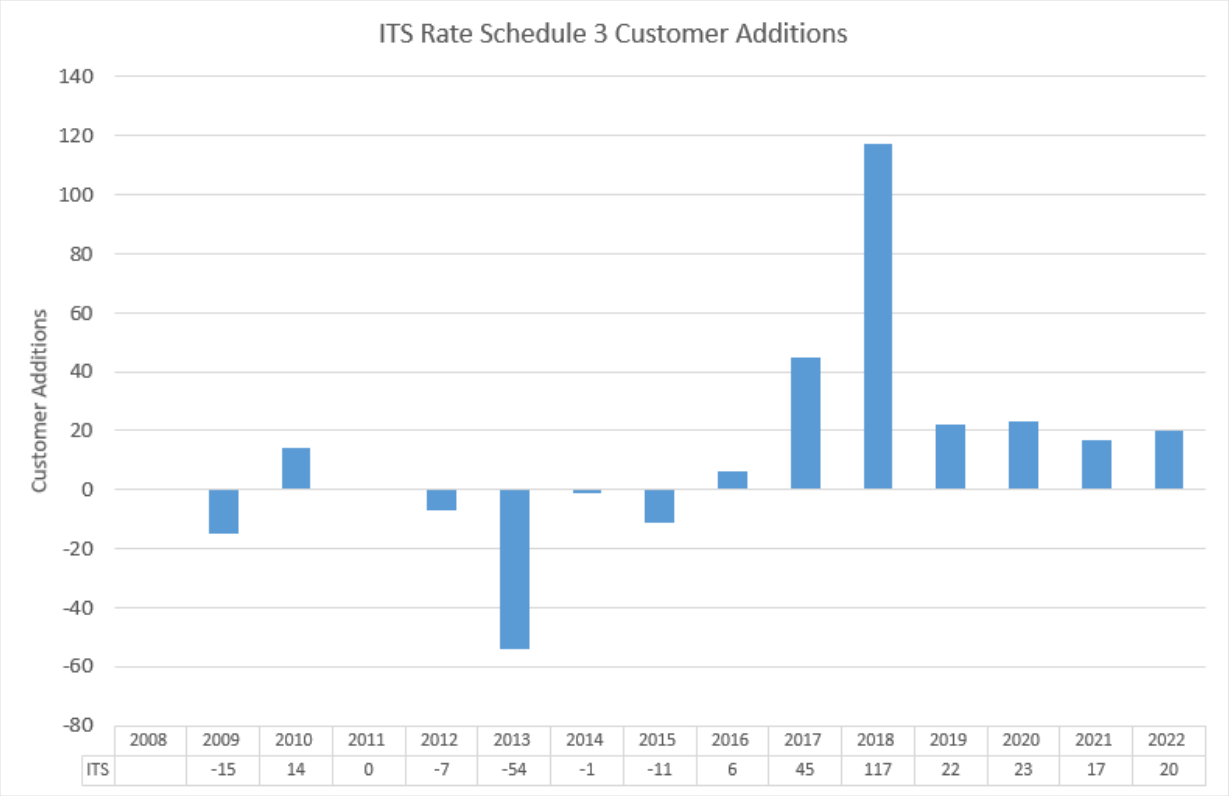


Table 1 below compares the annual growth rate in the respective forecasts by rate class. As can be seen, the growth rates assumed through the Updated Application are generally higher in all rate classes, but particularly in RS 3 in 2019 through 2024. This explains the rapid divergence between the two forecasts through that period. As noted in the response to BCUC Supplementary IR1 2.2, the RS 3 growth rate for 2025 and beyond was attenuated so for 2026 and beyond, the RS 3 growth rates are similar. Nonetheless, with the spread in remaining rate class growth rates, the Updated Application showed a higher rate of growth in aggregate, as illustrated in Figures 2-1 and 2-2 of the Supplementary Filing.

Table 1: Forecast Annual Growth Rate by Rate Class – Supplementary Filing Forecast vs Updated Application Forecast

Year	Supplementary Filing Forecasted Account Growth by Rate Class			
	1	2	3	23

Year	Updated Application Forecasted Account Growth by Rate Class			
	1	2	3	23
2019	2.1%	1.0%	9.1%	1.2%
2020	1.7%	1.1%	8.5%	1.2%
2021	1.5%	1.1%	8.1%	1.2%

Year	Supplementary Filing Forecasted Account Growth by Rate Class			
	1	2	3	23
2022	0.8%	0.6%	1.2%	1.1%
2023	0.7%	0.6%	1.2%	1.2%
2024	0.7%	0.6%	1.2%	1.2%
2025	0.6%	0.6%	1.1%	1.1%
2026	0.6%	0.6%	1.1%	1.1%
2027	0.6%	0.6%	1.1%	1.1%
2028	0.5%	0.6%	1.1%	1.1%
2029	0.5%	0.6%	1.2%	1.1%
2030	0.5%	0.6%	1.2%	1.1%
2031	0.5%	0.6%	1.2%	1.1%
2032	0.5%	0.6%	1.2%	1.1%
2033	0.5%	0.6%	1.1%	1.1%
2034	0.5%	0.6%	1.1%	1.1%
2035	0.5%	0.6%	1.1%	1.1%
2036	0.5%	0.6%	1.1%	1.1%
2037	0.5%	0.6%	1.1%	1.0%
2038	0.4%	0.6%	1.1%	1.0%
2039	0.4%	0.6%	1.1%	1.0%

Year	Updated Application Forecasted Account Growth by Rate Class			
	1	2	3	23
2022	1.4%	1.1%	7.7%	1.2%
2023	1.4%	1.1%	7.1%	1.2%
2024	1.3%	1.1%	6.7%	1.2%
2025	1.2%	1.0%	1.1%	1.2%
2026	1.1%	1.1%	1.1%	1.2%
2027	1.0%	1.1%	1.2%	1.2%
2028	1.1%	1.1%	1.2%	1.2%
2029	1.0%	1.1%	1.2%	1.2%
2030	1.0%	1.1%	1.1%	1.2%
2031	0.9%	1.0%	1.1%	1.2%
2032	0.9%	1.0%	1.1%	1.2%
2033	0.8%	1.1%	1.1%	1.2%
2034	0.8%	1.0%	1.1%	1.2%
2035	0.7%	1.0%	1.1%	1.2%
2036	0.7%	1.0%	1.0%	1.1%
2037	0.6%	1.0%	1.0%	1.1%
2038	0.6%	0.9%	1.0%	1.1%
2039	0.6%	0.9%	1.0%	1.0%

1.4 Please provide a table that compares forecasted (based on the 2019 peak demand forecast) and actual values in 2019, 2020, 2021 and 2022 for the following:

- Total ITS customer accounts
- Total ITS customer account annual growth rate
- ITS peak demand

1.4.1 Please provide a detailed discussion of the causes behind the differences between the actual and forecasted values.

Response:

Please see Table 1 below which compares the forecast and actual ITS customer accounts by rate schedule and the peak demand for 2019 through 2022 (based on the 2019 Peak Demand Forecast). Table 2 below provides the forecast and actual ITS customer account annual growth rates for 2019 through 2022 (based on the 2019 Peak Demand Forecast).

As shown in Table 1, the actual customer account totals and peak demand results are reasonably consistent with the forecast values, differing at most by 1.2 percent and 1.3 percent, respectively. Further, in 2022, the difference between forecast and actual ITS peak demand was only 0.7 percent. The variances between the forecast and actual peak demand are attributable to the actual UPC_{peak} and actual account additions being lower than forecast, particularly in 2020 and 2021. Contracted industrial demand was constant during 2019 through 2022 and did not contribute to the variances.

The 2020 actual rate of customer account growth shown in Table 2 was lower than forecast (1.4 percent actual growth rate compared to 1.7 percent forecast growth rate), causing the forecast and historic peak demand curves to diverge slightly. However, as shown in Table 2, the actual customer growth rate in 2022 exceeded the forecast growth rate by 0.1 percent. That, coupled with an increase in UPC_{peak} between 2021 and 2022, reduced the spread between forecast and actual peak demand to only 0.7 percent.

The customer accounts and historic peak demand are shown to be keeping pace with that of the Updated Application Forecast and this further underscores the urgent need for additional pipeline capacity in the ITS to ensure customer needs are met during periods of peak demand. As discussed in the response to BCUC Supplementary IR1 1.3, variations in annual forecast growth rates are often observed and are largely attributed to changes in assumptions pertaining to customer account totals; however, in all scenarios, growth continues to be observed and is expected to exceed existing system capacity levels, even with mitigations in place, by 2026.

Table 1: ITS Customer Account and Peak Demand

ITS Customer Accounts by Rate Schedule	2019 Peak Demand Forecast				Actual (Year End)			
	2019	2020	2021	2022	2019	2020	2021	2022
1	180,210	183,317	186,105	188,751	178,995	181,660	183,896	186,700
2	16,787	16,964	17,146	17,331	16,782	16,950	17,045	17,208
3	685	744	804	865	650	674	693	713
23	204	207	209	212	196	184	181	179
4	2	2	2	2	6	7	5	9
5	18	18	18	18	25	27	28	29
6	0	0	0	0	0	0	0	0

ITS Customer Accounts by Rate Schedule	2019 Peak Demand Forecast				Actual (Year End)			
	2019	2020	2021	2022	2019	2020	2021	2022
7	0	0	0	0	0	0	0	0
22	6	6	6	6	6	6	6	6
25	51	51	51	51	46	46	44	42
27	11	11	11	11	14	15	16	16
Total ITS Customer Accounts (% difference Forecast to Actual)	197,974	201,319	204,352	207,247	196,720 (-0.6%)	199,569 (-0.9%)	201,914 (-1.2%)	204,902 (-1.1%)
ITS Peak Demand in TJ/d (% difference Forecast to Actual)	321	327	333	338	319 (-0.5%)	322 (-1.3%)	328 (-1.3%)	336 (-0.7%)

Table 2: ITS Customer Account Annual Growth Rates

ITS Customer Accounts Annual Growth Rate by Rate Schedule	2019 Peak Demand Forecast				Actual (Year End)			
	2019	2020	2021	2022	2019	2020	2021	2022
1		1.7%	1.5%	1.4%		1.5%	1.2%	1.5%
2		1.1%	1.1%	1.1%		1.0%	0.6%	1.0%
3		8.5%	8.1%	7.7%		3.7%	2.8%	2.9%
23		1.2%	1.2%	1.2%		-6.1%	-1.6%	-1.1%
4		0.0%	0.0%	0.0%		16.7%	-28.6%	80.0%
5		0.0%	0.0%	0.0%		8.0%	3.7%	3.6%
6		-	-	-		-	-	-
7		-	-	-		-	-	-
22		0.0%	0.0%	0.0%		0.0%	0.0%	0.0%
25		0.0%	0.0%	0.0%		0.0%	-4.3%	-4.5%
27		0.0%	0.0%	0.0%		7.1%	6.7%	0.0%
Total ITS Customer Accounts Growth Rate		1.7%	1.5%	1.4%		1.4%	1.2%	1.5%

Note to Tables 1 and 2:

Interruptible rate class customer accounts (RS 22, 7 and 27) are shown in Tables 1 and 2; however, as explained in the response to BCUC Supplementary IR1 1.6, interruptible volumes do not contribute to peak demand in the forecast. Similarly, Seasonal (RS 4) account totals are shown but do not contribute to peak demand totals.

1.5 Please confirm whether FEI still assumes that industrial peak demand remains flat for the 2022 peak demand forecast. If not confirmed, please explain, and provide a table showing the peak demand of industrial customers throughout the planning horizon.

Response:

Confirmed.

1.6 Please discuss whether there have been any changes in peak demand for interruptible customers for the 2022 peak demand forecast, compared to the 2019 peak demand forecast. If yes, please provide a table showing the peak demand of interruptible customers across the planning horizon, and provide an explanation for any changes.

Response:

FEI confirms that interruptible volumes were not, and are not, included in the peak demand forecasts, as FEI sizes the system to meet the needs of firm customers on a design degree day. As such, in both the 2022 and 2019 peak demand forecasts, the component of the load due to interruptible rates was zero.

1.7 Please provide the updated BC Stats Forecast, CBOC Housing Starts for BC, and ITS account, ITS account growth rate, and peak demand forecast details by rate schedules for the Supplementary Filing similar to Appendix L of the Updated Application.

Response:

Please refer to Attachment 1.7 for live excel spreadsheets of the updated appendices.

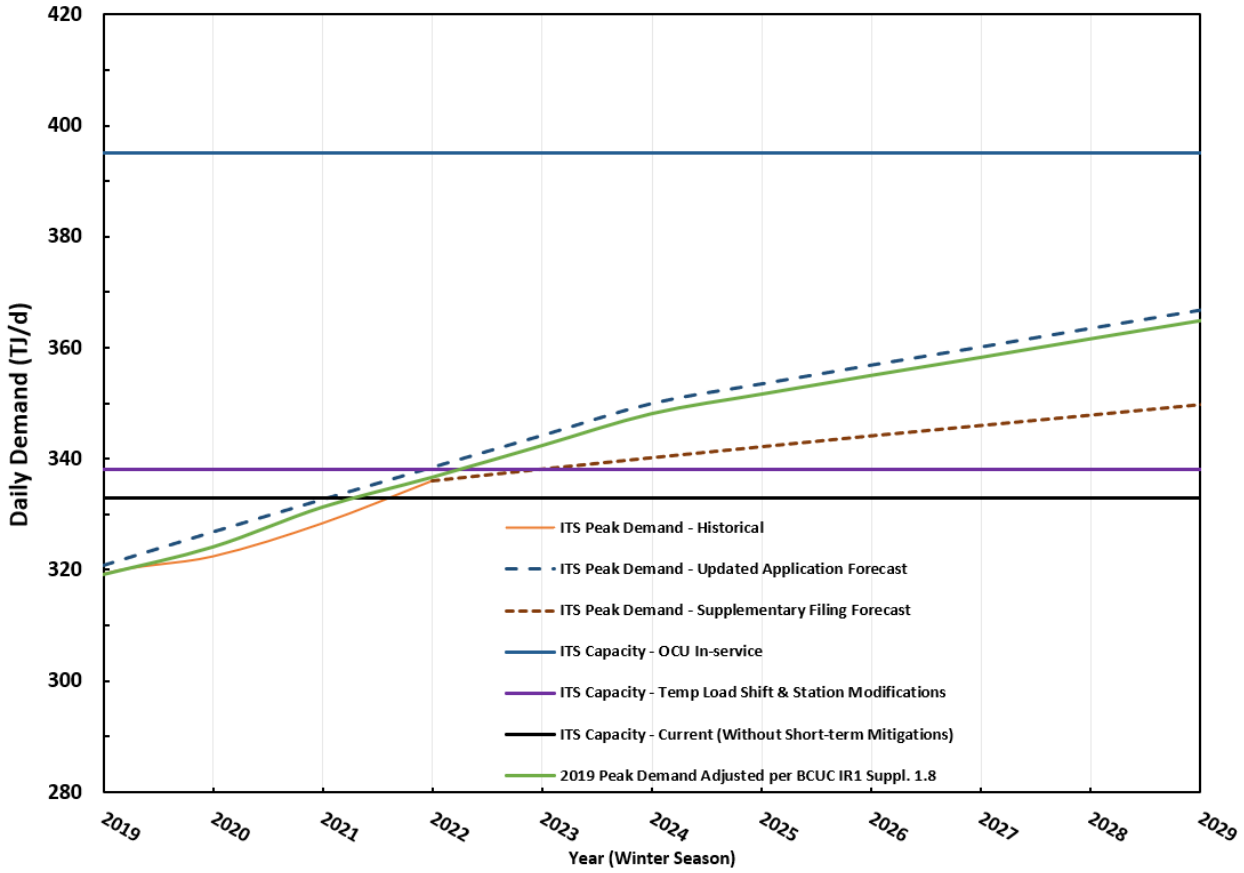
1.8 Please provide an analysis, which shows the ITS peak demand forecast that applies the following actual values from 2020 – 2022 to the 2019 peak demand forecast model (i.e. keeping other 2019 assumptions the same):

- Customer additions for residential and commercial rate schedules;
- Firm industrial peak demand; and
- Contracted demand for interruptible customers.

1.8.1 Please discuss the variance with actual peak demand in 2020 – 2022, and the forecasted demand from the 2022 peak demand forecast.

Response:

FEI provides the following figure which is an updated version of Figure 2-2 from the Supplementary Filing with an additional curve (green solid curve). This new curve, which FEI refers to as the Adjusted 2019 Peak Demand in this IR response, was developed based on the 2019 peak demand forecast model (i.e., the Updated Application Forecast) but includes actual year-end customer additions, firm industrial peak demand and contracted demand for interruptible customers for years' 2019 to 2022. All other assumptions remain the same from the 2019 peak demand model (as requested in this IR). FEI notes that for the forecast period, 2023 and onwards, the growth rate of the Updated Application Forecast was applied, originating at the 2022 data point. The 2019 Adjusted Peak Demand curve shows that, with the inclusion of the actual customer additions for 2019 through 2022, the curve trends very closely to the Updated Application Forecast.



As shown in the above figure, for the historic period (i.e., pre-2023), the Adjusted 2019 Peak Demand is higher than the Historic Peak Demand (orange curve) but lower than the Updated Application Peak Demand (blue dotted curve). FEI explained in the response to BCUC Supplementary IR1 1.4 that the actual customer account totals for 2019 to 2022 were slightly less than those forecasted in the Updated Application. Thus, when the actual 2019 to 2022 customer account totals are included in the Adjusted 2019 Peak Demand, the resulting curve is slightly lower due to lower daily demand than in the Updated Application. With all other 2019 assumptions held constant, the UPC_{peak} values applied in this IR response are consistent with the Updated Application Forecast. As noted in the response to BCUC Supplementary IR1 3.3, UPC_{peak} values in 2020 and 2021 were lower than those used in the Updated Application, which explains why the Adjusted 2019 Peak Demand is higher than the Historic Peak Demand (i.e., the Historic Peak Demand includes the lower of both customer accounts and UPC_{peak} values). As the UPC_{peak} values increased from 2021 to 2022, the gap between UPC_{peak} for 2019 and 2022 decreased, and so did the difference between the resulting demand and the Historic Peak Demand.

The reason that there is larger gap between the Adjusted 2019 Peak Demand Forecast and the Supplementary Filing Forecast compared to the Adjusted 2019 Peak Demand Forecast and the Updated Application Forecast is due to the growth rate assumptions. The Adjusted 2019 Peak

Demand Forecast utilizes the higher growth rate embedded in the Updated Application Forecast. As the actual growth rate data for 2019-2022 provided in the response to BCUC Supplementary IR1 1.4 shows, the growth rate embedded in the Updated Application Forecast is likely more reasonable than the growth rate embedded in the Supplementary Filing Forecast. Accordingly, FEI considers the Adjusted 2019 Peak Demand Forecast to further support the Updated Application Forecast.

Contracted demand was not a contributor to the variances described above as the values were constant through the period discussed. The data underlying the Adjusted 2019 Peak Demand is provided in the following table.

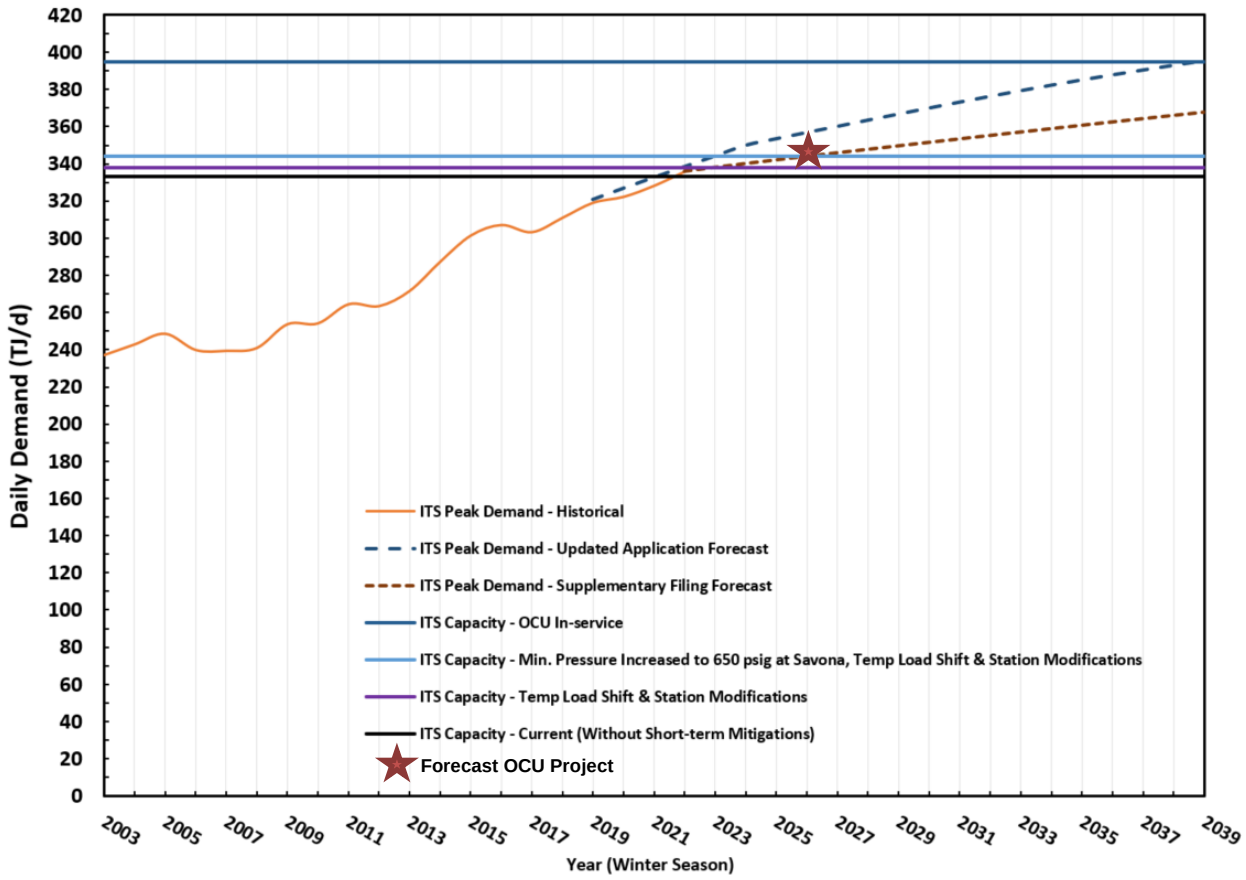
Year	Updated Application Peak Demand TJ/d	Supplementary Filing Peak Demand TJ/d	2019 Peak Demand Forecast in Updated Application with 2019 - 2022 Account Actuals TJ/d	Customer Account Basis
2019	321		319	2019 Year End
2020	327		324	2020 Year End
2021	333		331	2021 Year End
2022	338	336	337	2022 Year End
2023	344	338	342	Updated Application Forecast Growth Rate Applied
2024	350	340	348	
2025	353	342	352	
2026	357	344	355	
2027	360	346	358	
2028	363	348	362	
2029	367	350	365	
2030	370	352	368	
2031	373	353	371	
2032	376	355	374	
2033	379	357	377	
2034	382	359	380	
2035	385	361	383	
2036	388	363	386	
2037	390	364	388	
2038	393	366	391	
2039	395	368	393	

1.9 Please provide an annotated version of Figure 2-1 that shows current ITS capacity, ITS capacity with temporary load shift and station modifications, ITS capacity with temporary load shift, station modifications, and increased Savona tap pressure, ITS project completion, ITS capacity with OCU in service, and ITS capacity with OCU in service and compressor upgrades (if any).

1.9.1 Please also provide the answers to the previous question in a table format with data points.

Response:

Please see the updated Figure 2-1 below and the accompanying table with the addition of the ITS capacity with temporary load shift, station modifications, and increased Savona tap pressure. FEI interprets the reference in the IR to "ITS project completion" as the year the OCU Project is expected to be in-service. As discussed in Section 3 of the Supplementary Filing, the OCU Project is expected to be in-service before Winter 2026/2027, which is marked on the figure below as an orange star. With regard to compressor upgrades, as discussed in the response to BCUC Supplementary IR1 1.10, compressor upgrades no longer have an impact on the capacity with the OCU Project in-service due to the revised pressure assumption at the Yahk Tap.



1

Year	Current ITS Capacity	Load Shift and Station Modifications	Load Shift, Stn Mods, 650psig at Savona Tap	Capacity with OCU	Supplementary Filing Peak Demand	Updated Application Peak Demand
2019	333	338	344	395		321
2020	333	338	344	395		327
2021	333	338	344	395		333
2022	333	338	344	395	336	338
2023	333	338	344	395	338	344
2024	333	338	344	395	340	350
2025	333	338	344	395	342	353
2026	333	338	344	395	344	357
2027	333	338	344	395	346	360
2028	333	338	344	395	348	363
2029	333	338	344	395	350	367
2030	333	338	344	395	352	370
2031	333	338	344	395	353	373

Year	Current ITS Capacity	Load Shift and Station Modifications	Load Shift, Stn Mods, 650psig at Savona Tap	Capacity with OCU	Supplementary Filing Peak Demand	Updated Application Peak Demand
2032	333	338	344	395	355	376
2033	333	338	344	395	357	379
2034	333	338	344	395	359	382
2035	333	338	344	395	361	385
2036	333	338	344	395	363	388
2037	333	338	344	395	364	390
2038	333	338	344	395	366	393
2039	333	338	344	395	368	395
2040	333	338	344	395	370	398
2041	333	338	344	395	371	400
2042	333	338	344	395	373	403

1.10 Please confirm, or explain otherwise, that the ITS capacity, with the OCU in service, for the Supplementary Filing is different from the Updated Application.

1.10.1 If confirmed, please explain why.

1.10.2 If not confirmed, please explain why the line of ITS capacity, with OCU in service, shown on Figure 2-1 and 2-2 of the Supplementary Filing is higher than the ITS capacity with OCU shown in Figure 3-8 of the Updated Application. Additionally, please clarify whether the ITS capacity with the OCU in service stated in the Supplementary Filing includes additional compressor upgrades or not.

Response:

Confirmed. Figure 3-8 of the Updated Application shows a lower capacity value than that provided in the Supplementary Filing. This is due to the assumed tap pressure at Yahk being 650 psig at the time of filing the Updated Application. The capacity shown in Figure 3-8 of the Updated Application was therefore constrained by the need for additional compression at the Kitchener B compressor station. The contractual minimum tap pressure at the Yahk interconnect with TC Energy Inc. has been confirmed to be 750 psig, and correspondingly the capacity assessment for the ITS with the OCU Project in service has been updated to 395 TJ/d. Please refer to the responses to the RCIA IR2 32 series which clarify the contract pressure details at the Yahk interconnect.

1.11 Please confirm whether the historical peak demand shown in Figure 2-1 for 2019-2022 represents the actual measured peak demand, or if it is weather adjusted. If it is measured peak demand, please provide a discussion on the impact of the recorded weather conditions on the peak day for each year.

Response:

The historical peak demand shown in Figure 2-1 for 2019-2022 is an estimation of peak demand on a design degree day based on historical customer account totals with UPC_{PEAK} values applied for each respective rate class.

FEI provided the following explanation regarding temperature normalization in the response to BCSEA IR1 3.6:

> Temperature normalization is not considered in peak demand forecasting. Peak demand for system capacity planning purposes is determined using extreme winter temperatures, not typical or normal winter weather. This is to ensure that FEI has sufficient infrastructure in place to meet the forecast demand of its customers at all times, even during peak periods that occur during low temperature conditions.

Further, in the response to BCSEA IR1 3.6.1, FEI explained the following:

> The historical peak demand values shown in Figure 3-6 of the Updated Application are the historical estimates of peak demand under design temperature conditions from FEI's hydraulic models for the ITS. The values do not represent the actual peak demand on the ITS for the coldest day that occurred in 2019 or any previous year represented in the figure.

2.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-2; BCUC IR 6.5; FEI 2022 Long Term Gas Resource Plan proceeding, Exhibit B- 23, BCUC IRs 103, 103.1.1, 104.9

Customer Account Additions Forecast

In its response to BCUC IR 6.5, FEI stated:

> The forecast RS 3 customer growth rate is higher than the other rate schedules from 2019-2024 due to the unusually high number of RS 3 customers that were added to the system in 2018. As shown in Figure below:
>
> 1. Prior to 2017 and 2018 RS 3 customer additions were low.
> 2. In 2017 and 2018 RS 3 customer additions increased sharply.
>
> a. The red rectangle indicates the data used to develop the RS 3 customer additions forecast (using a three-year average).

Figure 1: RS 3 Actual Customer Additions

> As shown in Figure 2 below:
>
> 1. Line segment 1 shows the actual RS 3 customers.
> 2. Line segment 2 shows the result of the commercial customer forecast from 2019 to 2024.
> 3. Line segment 3 shows the long-term result of continuing to add the forecast annual additions each year, through 2039. This forecast was considered unreasonable because:
>
> • There was no apparent cause for the customer increase in 2018.
>
> • Based on Grubbs Outlier test4 the 2018 value of customer additions was an outlier.

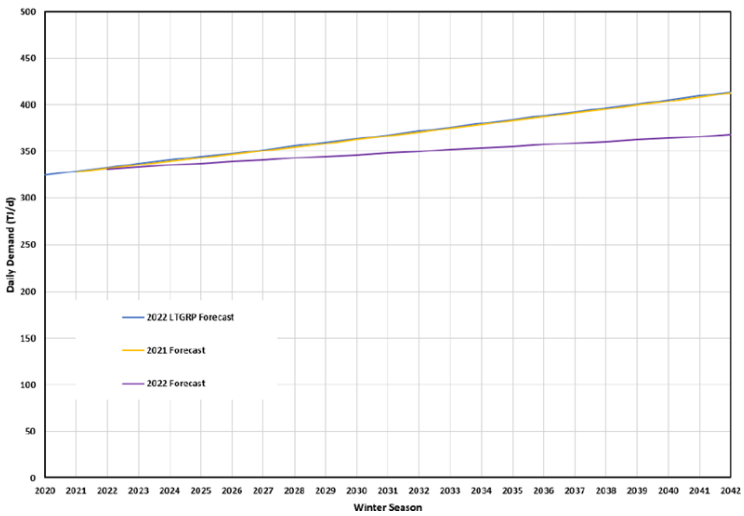
4. Line segment 4 shows the adjustment FEI made to the forecast in 2025.

As a result of the adjustment the annual RS 3 customer growth rate from 2025 through 2039 is now similar to the other rate schedules as per the "ITS Inc. Acct Growth" tab in Appendix L-3 to the Updated Application.

Figure 2: RS 3 Customer Forecast

In response to BCUC IR 103 from the 2022 Long Term Gas Resource Plan (2022 LTGRP), FEI provided ITS Traditional Peak Demand Comparison:

Figure 3: ITS Traditional Peak Demand Comparison

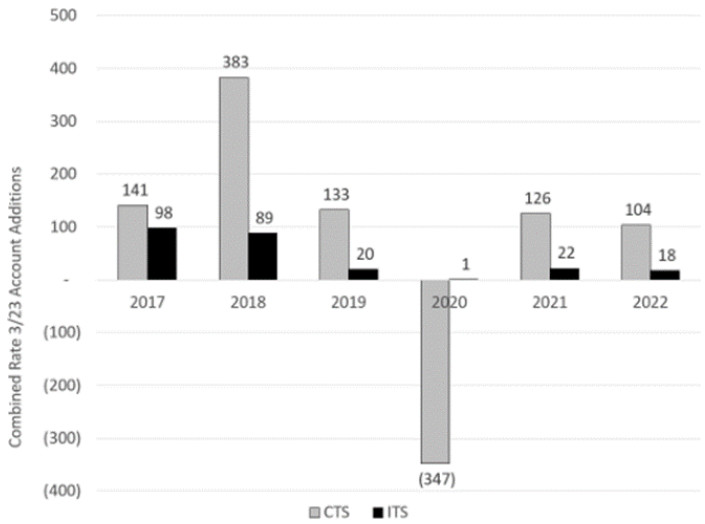


In its response to BCUC IR 103.1.1 from the 2022 LTGRP, FEI stated:

> Figure 1 shows the annual account additions/subtractions for the five years preceding the 2022 forecast. Data for the 2022 year-end is now available and

shown for reference, though it was not used in the development of the 2022 forecast which was produced last year.

Figure 1: CTS and ITS Rate 3 & 23 Account Additions



In the CTS, in 2018 a large number of additions were noted which may have been related to the rupture incident on the Enbridge T-South pipeline in late 2018, prompting interruptible customers to take up firm contracts. The correspondingly low value in 2020 may in part be a correction of that 2018 spike. For both the CTS and ITS, FEI further speculates that the emergence of the COVID-19 pandemics could have been a factor in the low account addition totals for that year. [emphasis added]

In response to BCUC IR 104.9 from the 2022 LTGRP, FEI provides a table of the magnitude and direction of Traditional Peak Demand for its three major transmission systems:

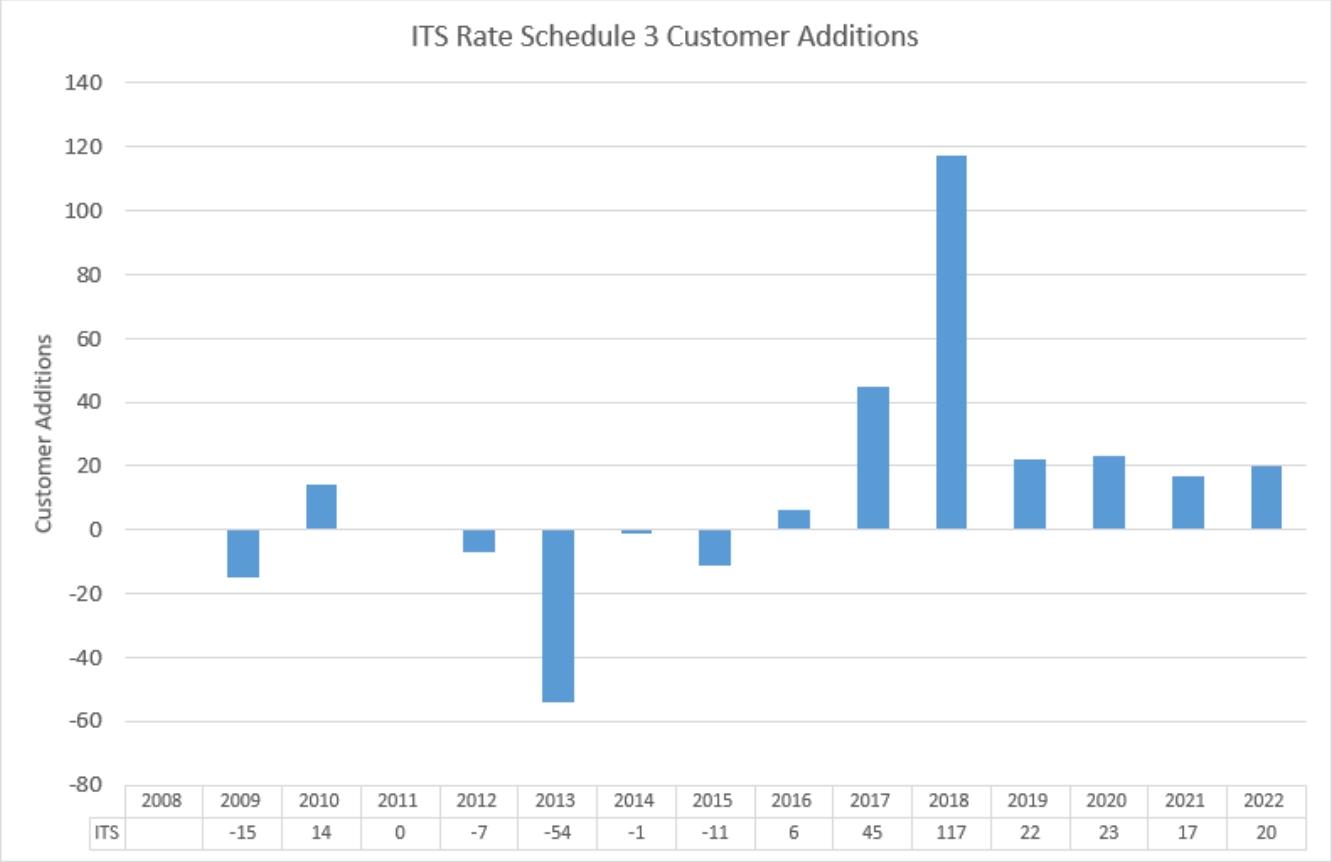
Region / Transmission System	Customer Class	DEP Annual Forecast	Traditional Peak Demand Forecast
VITS	Residential	0.89 PJ decrease	29.0 TJ/day increase
	Small Commercial	0.22 PJ decrease	20.5 TJ/day increase
	Large Commercial	0.96 PJ decrease	2.5 TJ/day increase
	Industrial	1.33 PJ decrease	no change
	Combined[36]	3.40 PJ decrease	52 TJ/day increase
CTS	Residential	17.08 PJ decrease	45.1 TJ/day increase
	Small Commercial	3.06 PJ decrease	53.7 TJ/day increase
	Large Commercial	8.70 PJ increase	226.3 TJ/day increase
	Industrial	5.16 PJ decrease	no change
	Combined[1]	16.60 PJ decrease	325.1 TJ/day increase
ITS	Residential	4.49 PJ decrease	22.5 TJ/day increase
	Small Commercial	1.09 PJ decrease	13.6 TJ/day increase
	Large Commercial	3.20 PJ increase	68.1 TJ/day increase
	Industrial	4.28 PJ decrease	no change
	Combined[1]	6.66 PJ decrease	104.2 TJ/day increase

2.1 Please provide an updated graph of actual RS 3 customer additions/subtractions from 2019 to 2022 for the ITS system.

Response:

Figure 1 below provides the requested updated graph.

Figure 1: Updated 2019 to 2022 Actual RS 3 Customer Additions/Subtractions

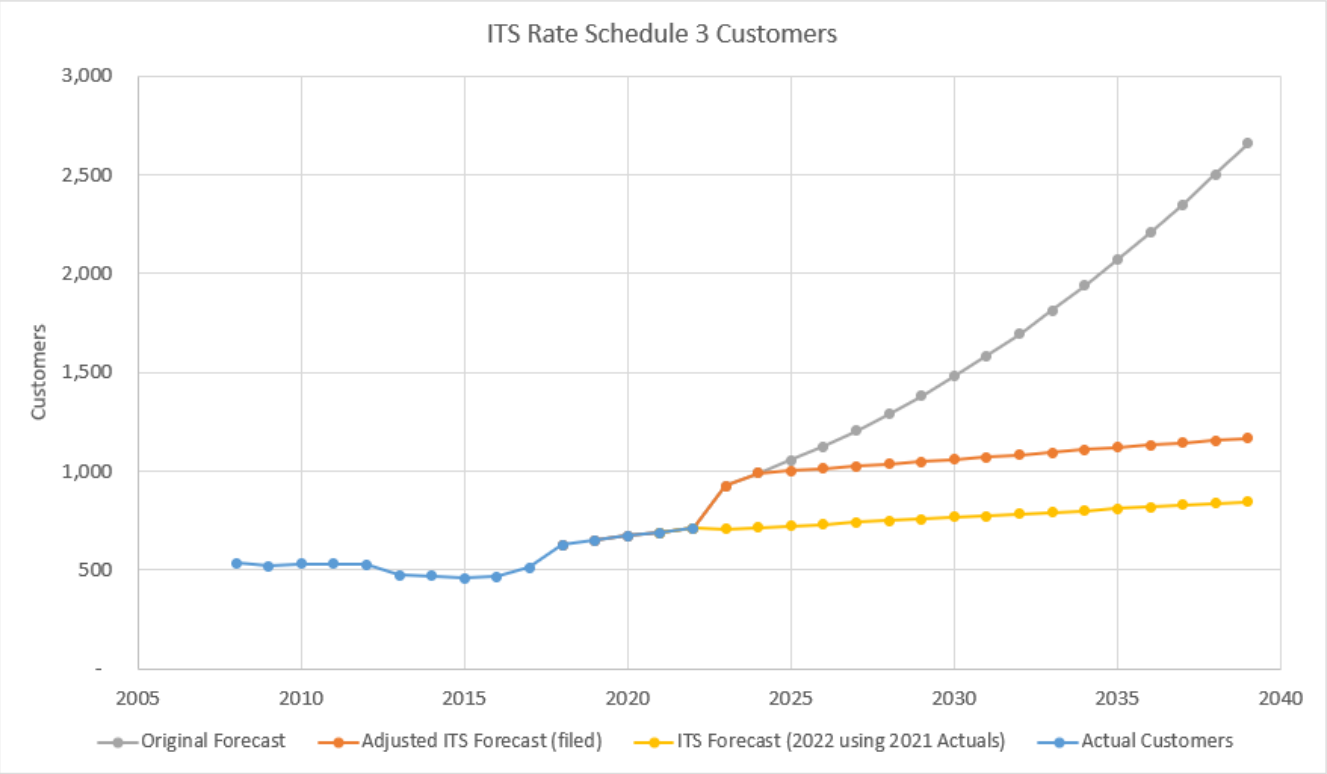


2.2 Please update Figure 2 of the RS 3 customer forecast in the preamble for the new ITS peak demand forecast. Additionally, please discuss in detail any adjustments made.

Response:

The following Figure 1 is an update to Figure 2 in the preamble. The yellow line represents the RS 3 customer additions forecast for the ITS and is based on 2021 actual data. The slope of the new forecast is very similar to the Adjusted ITS Forecast (orange) and confirms that the original decision to treat the 2018 additions as an outlier and adjust the forecast was appropriate.

Figure 1: Updated Figure 2 – RS 3 Customer Forecast



2.3 Please confirm, or explain otherwise, that a significant reduction of customer account additions on the ITS system from 2019 to 2022 only occurs in RS 3.

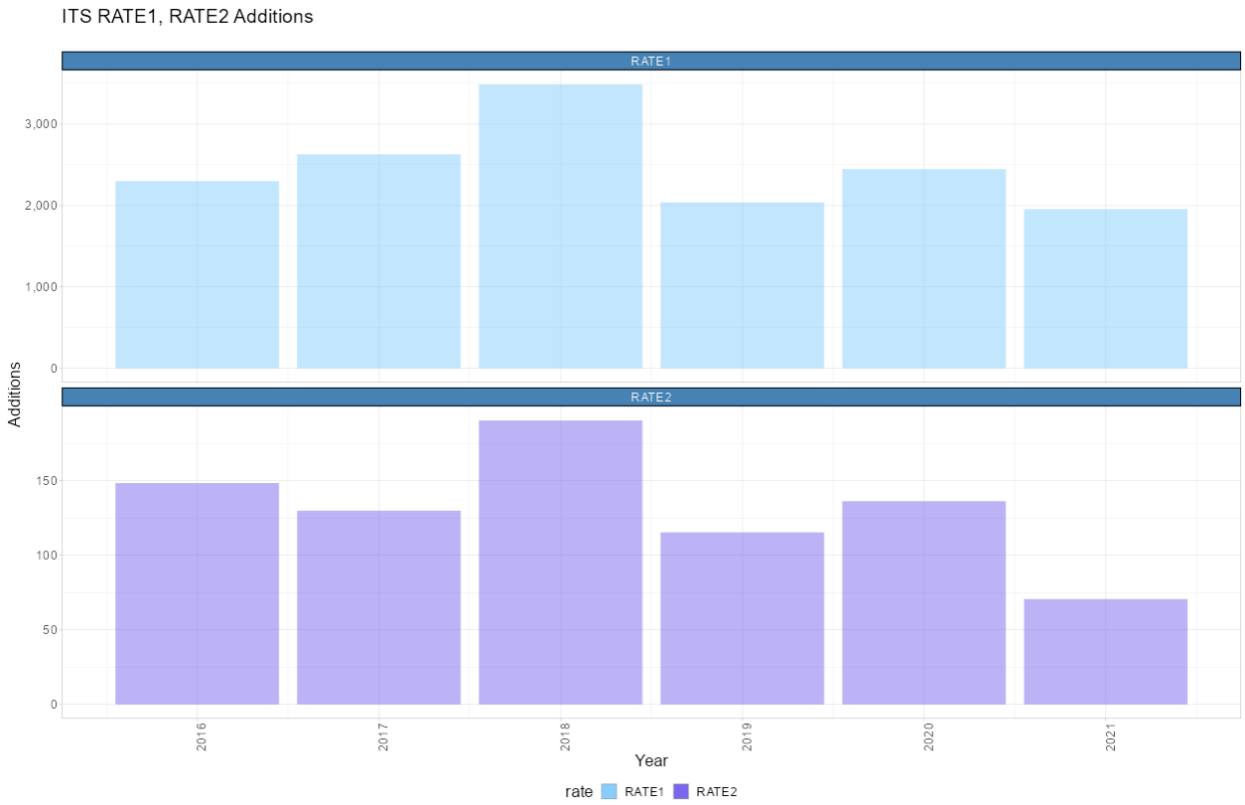
2.3.1 If confirmed, please discuss any observed trends for RS 1 and RS 2 customer account additions from 2019 to 2022.

2.3.2 If not confirmed, please provide a table showing the reduction of customer account additions for RS 1 and RS 2 from 2019 to 2022.

Response:

Confirmed. As shown in Figure 1 below, RS 1 and RS 2 customer additions were higher in 2018 than in other years; however, RS 1 and RS 2 customer additions did not decline to the same extent as RS 3 after 2018.

Figure 1: RS 1 and RS 2 Customer Additions 2016 to 2022



2.4 Please explain why the customer additions of RS 3 in 2017 and 2018 in Figure 1, provided in BCUC IR 6.5 response, were higher than the combined RS 3 and RS 23 in 2017 and 2018 in Figure 1, provided in BCUC IR 103.1.1 response to the 2022 Long Term Gas Resource Plan.

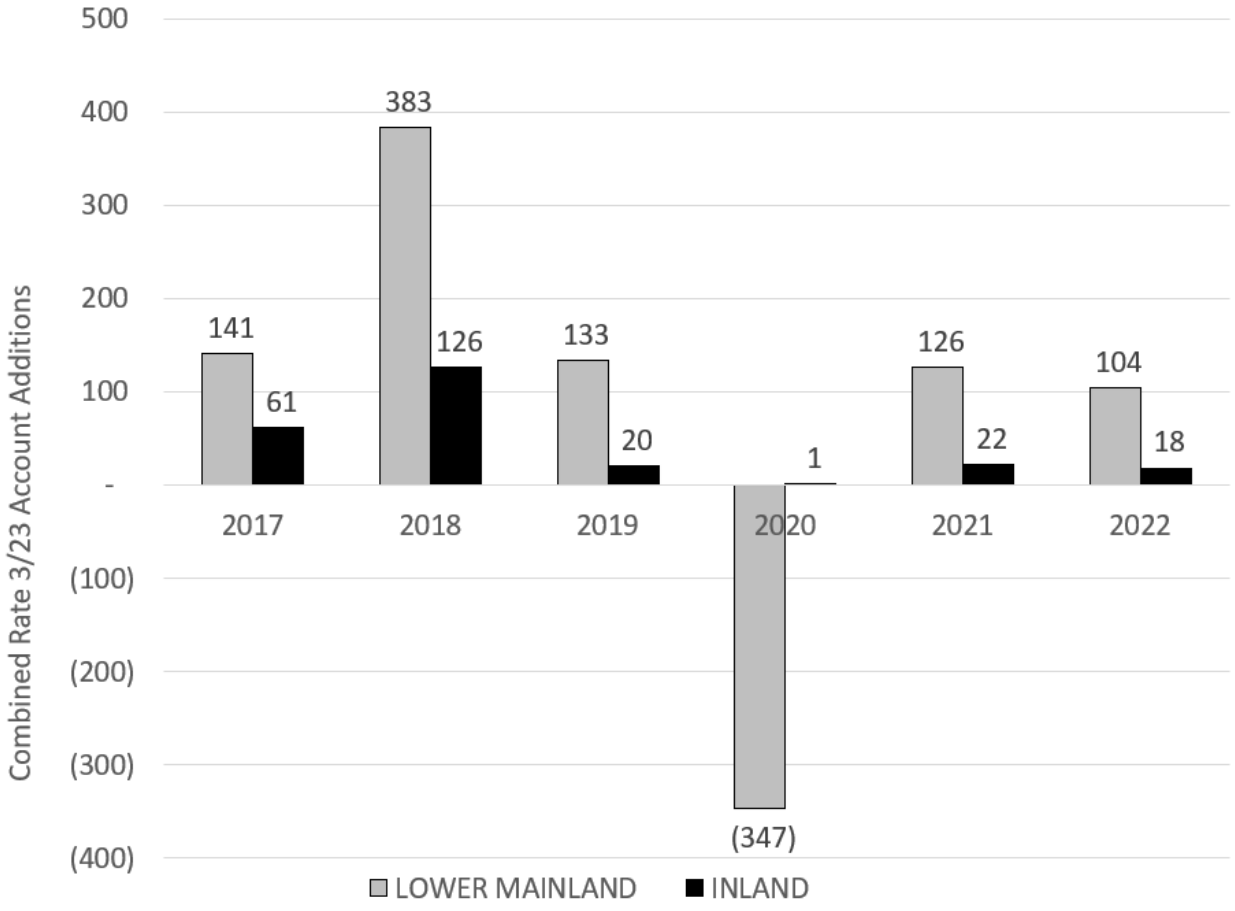
Response:

In examining the data provided in the responses to BCUC IR1 6.5 in the OCU proceeding and BCUC IR2 103.1.1 in the 2022 LTGRP proceeding, FEI discovered an incorrect value for the 2017 year-end RS 3 customer total which resulted in an error in the 2017 and 2018 customer additions values provided in Figure 1 in the response to BCUC IR2 103.1.1 in the 2022 LTGRP proceeding. Further, FEI clarifies that Figure 1 in the response to BCUC IR2 103.1.1 incorrectly identified the

areas in the figure as "CTS" and "ITS", when the correct references should have been to the "Lower Mainland" and "Inland" regions, respectively.

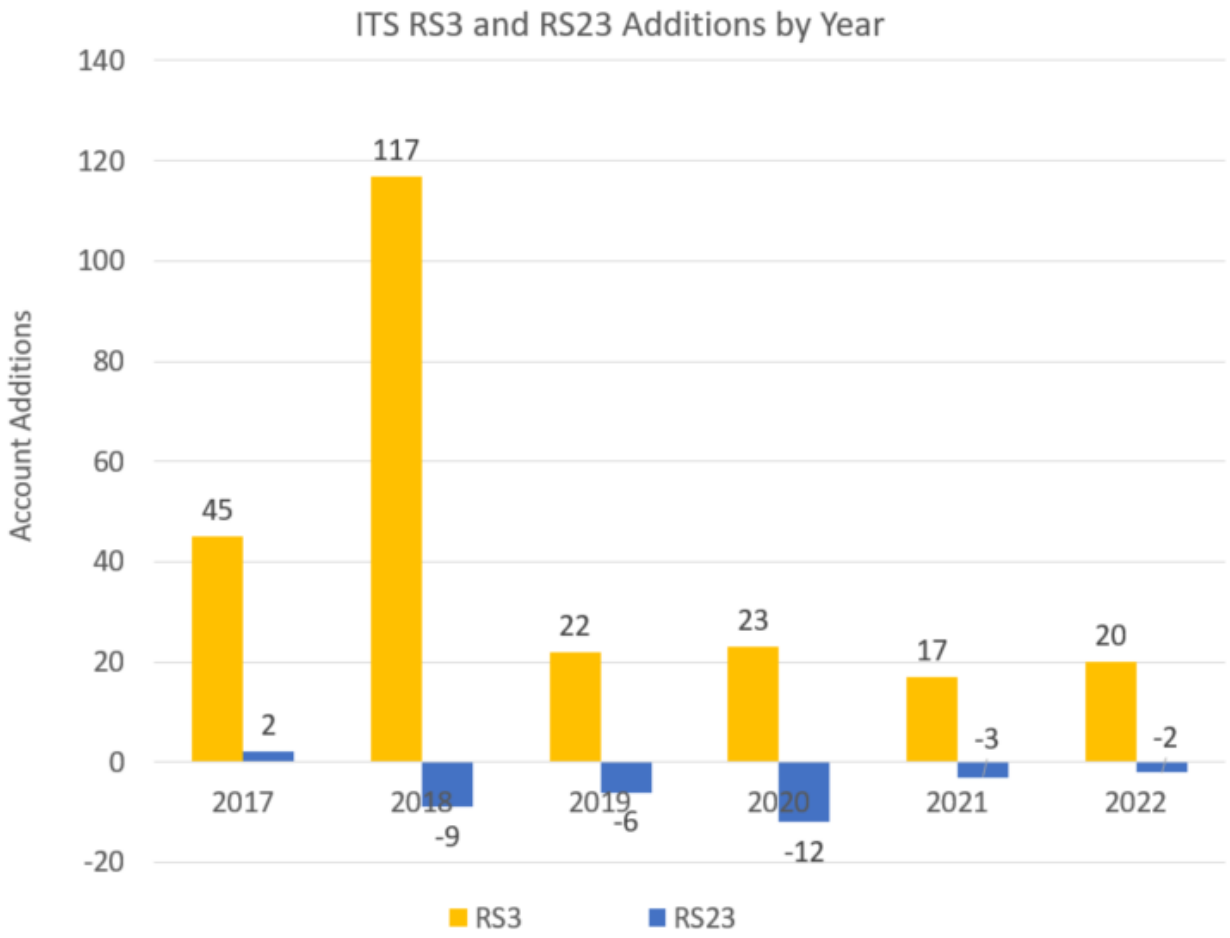
Figure 1 below provides the corrected Figure 1 from the response to BCUC IR2 103.1.1 in the 2022 LTGRP proceeding.

Figure 1: Corrected Figure 1 from LTGRP, BCUC IR2 103.1.1



FEI also created the following Figure 2 for the ITS which separately shows the RS 3 and RS 23 account additions by year to compare the information shown in Figure 1 from the response to BCUC IR1 6.5. The total RS 3 and RS 23 combined account additions for 2017 and 2018 in the corrected Figure 1 above are now both larger than the RS 3 totals in Figure 1 from the response to BCUC IR1 6.5, as would be expected given that the Inland area encompasses municipalities that are not included in the ITS.

Figure 2: ITS RS 3 and RS 23 Additions by Year



2.5 Please confirm whether the magnitude and direction of the peak demand forecast shown in the table in the preamble have been updated with the 2022 peak demand forecast for the ITS system.

2.5.1 If confirmed, please explain the 68.1 TJ/day increase in large commercial demand for the ITS system. Additionally, please discuss how this increase relates to the decrease in RS 3 customer additions from 2019 to 2022.

2.5.2 If not confirmed, please update the table in the preamble with the 2022 peak demand forecast for the ITS system.

Response:

Not confirmed. Please see Table 1 below which has been updated with information from the 2022 Peak Demand Forecast. There is no update available for the "DEP Annual Forecast" column as this was prepared specifically for the purposes of the 2022 LTGRP.

As noted in the preamble and referenced filings, the recent RS 3 customer additions have been lower than those of 2017 and 2018, but they remain positive in the ITS. As account forecasts are based on the most recent three years of history, as previously discussed, the rate of growth assumed for RS 3 customers in the 2022 Peak Demand Forecast is lower than that of the Updated Application. Nonetheless, the annual account forecast values remain positive, and while lower in the 2022 Peak Demand Forecast, growth in all rate classes is still anticipated.

Table 1: 2022 Peak Demand Forecast

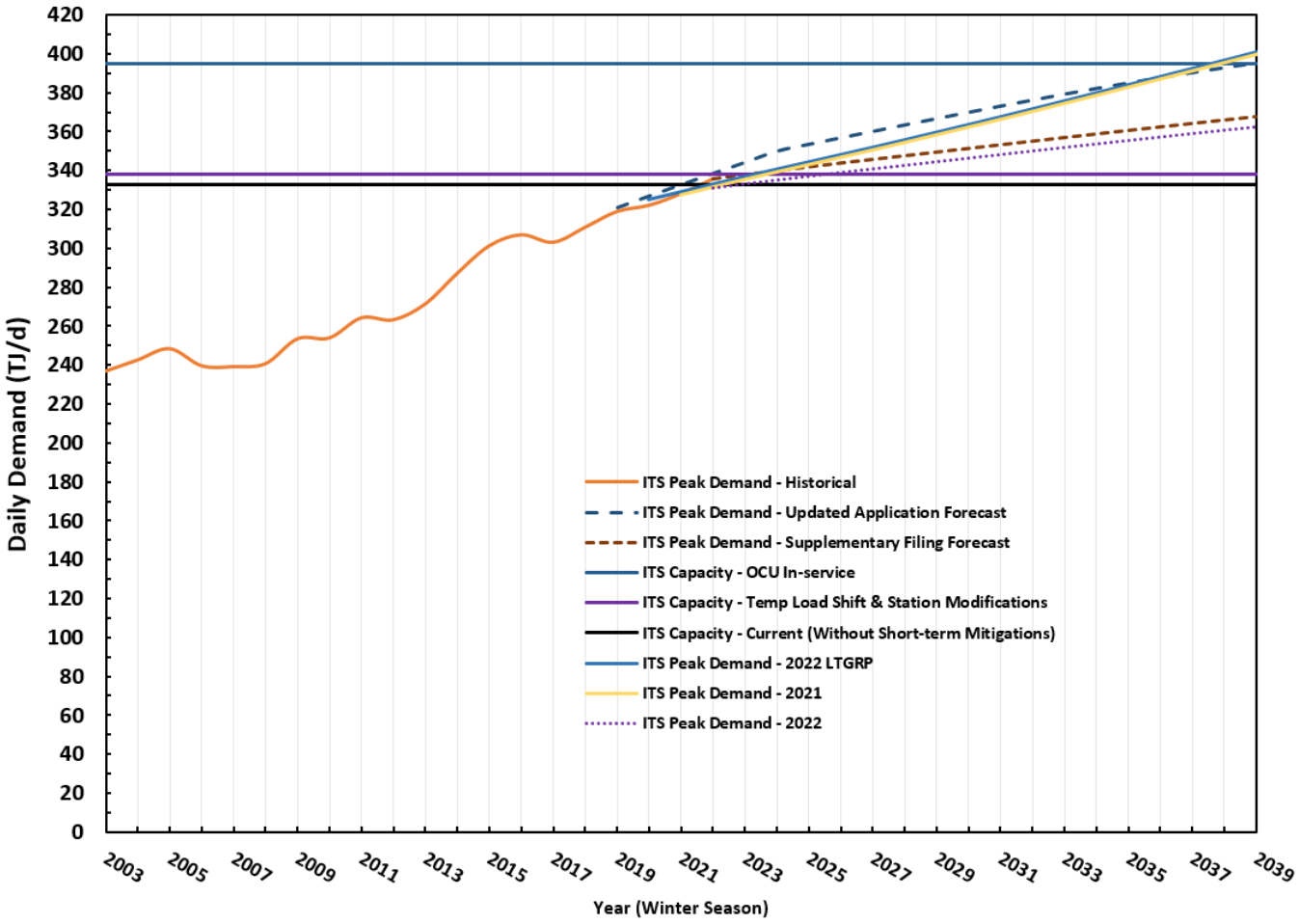
Transmission System	Customer Class	2022 Peak Demand Forecast	
ITS	Residential	22.4	TJ/day increase
	Small Commercial	10.1	TJ/day increase
	Large Commercial	4.1	TJ/day increase
	Industrial	no change	
	Combined	36.7	TJ/day increase

2.6 Please overlay Figure 3 of the ITS Traditional Peak Demand comparison shown in the preamble with Figure 2-1 of the Supplementary Filing Peak Demand Forecast.

Response:

The following Figure 1 overlays Figure 3 in the preamble to this IR with Figure 2-1 of the Supplementary Filing.

Figure 1: Overlay of Figure 3 with Figure 2-1



3.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-2, BCUC IRs 5.3; Exhibit B-14, BCUC IRs 42.3, 44.4, 44.7

UPCpeak, Demand-Side Management (DSM), and BC Energy Step Code

In response to BCUC IR 5.3, FEI stated:

> The UPCpeak for residential, small commercial, and large commercial customers does change from year to year as new forecasts are developed. It is reasonable to expect the values to continue to vary over time. […]
>
> FEI believes that the Traditional Peak Method which holds UPCpeak constant through the forecast remains appropriate. […] The UPCpeak values are refreshed annually, and then used in the forecast prepared that year, providing a regular check on the current state of peak demand requirements and potential future impact. [emphasis added]

In response to BCUC IR 42.3, FEI stated:

> […] FEI considers the impact of all future DSM measures to be relevant to future UPCpeak; however, FEI is uncertain of the net impact and is not yet capable of measuring the direct impact. As such, FEI is unable to speculate on UPCpeak changes over time in the peak demand forecast due to these measures. [emphasis added]

In response to BCUC IR 44.4, FEI stated:

> FEI has not observed a quantifiable impact on customers' peak load in the area since the adoption of the BC Energy Step Code in large municipalities in the Okanagan area including the Cities of Kelowna, Penticton and Vernon. As discussed in the response to BCUC IR1 5.2.1, some factors could reduce customer consumption on an annual basis, but depending on the means of achieving that efficiency, could drive peak demand up or down. FEI presently has no basis to determine this effect and is therefore uncertain as to the net direction or magnitude of change in UPCpeak of new customers overall as a result of the BC Energy Step Code. [emphasis added]

In response to BCUC IR 44.7, FEI stated:

> The three cities cited in the preamble have identified the following timelines for implementing the BC Energy Step Code:
>
> - City of Kelowna: currently requires Step 1 for new single family dwellings and townhouses, with Step 3 to be effective by June 1, 2021.

- City of Penticton: currently requires Step 1 for new single family dwellings and townhouses.
- City of Vernon: started consulting on the BC Step code; city council planning to adopt Step 1 by fall 2020, Step 2 by fall 2021, and Step 3 by spring 2022 for single family dwellings and townhouses.

From the City of Kelowna website[2], below is the information on the step code requirements adopted:

Kelowna Step Code Requirements

Part 9 Residential Building Requirements

As outlined in the Energy Step Code Implementation Strategy for Part 9 Residential Buildings, effective June 1, 2021 Part 9 residential buildings must be designed and constructed in compliance with **Step 3** of the Energy Step Code.

Part 3 Building Requirements

Energy Step Code for Part 3 buildings came into effect January 1, 2022. Part 3 building permit applications will need to demonstrate compliance with the following Energy Step Code requirements, depending on the building archetype, as outlined in the Energy Step Code Implementation Strategy for Part 3 Buildings:

- Group C - single detached residential occupancy: Step 4
- Group C - multi-unit residential occupancy of combustible construction (including hotels and motels): Step 3
- Group C - multi-unit residential occupancy of non-combustible construction: Step 2
- Group D - business and personal service occupancy: Step 2
- Group E - mercantile occupancy: Step 2

From the City of Penticton website[3], below is the information on the step code requirements adopted:

Penticton is Stepping Ahead

The BC Energy Step Code will soon be mandatory province-wide for all new residential and commercial buildings. In 2022, it will require 20% efficiency improvement over base code requirements, 40% in 2027 and 80% in 2032.

Here in Penticton, we now require part 9 residential buildings achieve a minimum of Step 3 of the BCESC, ahead of the province-wide mandatory compliance in fall of 2022. As of March 31st of this year, we will also require Part 3 complex commercial buildings to comply with step 1 of the BCESC. Click **here** for more information on requirements for Part 3 Buildings and our **Step Code Part-9** and **Step Code Part-3** bulletins. **This video** outlines the process.

Further, as of May 1, 2023, the first incremental change to the BC Building Code requires new construction to be 20% more energy efficient. The Step 3 standard for Part 9 buildings

[2] City of Kelowna Energy Step Requirements.
[3] City of Penticton Energy Step Requirements.

or the Step 2 standard for Part 3 will become universally applicable province wide as the new minimum acceptable standard for compliance with the BC Building Code.[4]

3.1 Please provide a comparison of the UPCpeak values assumed for RS 1, 2 and 3 in the 2019 peak demand forecast and the 2022 peak demand forecast.

Response:

Please refer to Table 1 in the response to BCUC Supplementary IR1 3.3 for a comparison of the 2019 and 2022 UPC_{peak} values. For clarity, the 2019 UPC_{peak} values in Table 1 were used in the 2019 peak demand forecast and the 2022 UPC_{peak} values in Table 1 were used in the 2022 peak demand forecast. As explained in the response BCUC IR1 3.2, FEI assumes these UPC_{peak} values remain constant in the respective forecasts.

3.2 Please confirm, or explain otherwise, whether for the 2022 peak demand forecast FEI still assumes the UPCpeak for existing and new customers from 2022 onwards is held constant.

3.2.1 If confirmed, please explain why.

3.2.2 If not confirmed, please provide the UPCpeak values used in the 2022 peak demand forecast for residential and commercial rate schedules in a table format, for each year of the forecast horizon.

Response:

Confirmed. In response to BCUC IR1 5.2, FEI describes its rationale for why it considers, and continues to consider, it appropriate to assume UPC_{peak} values constant for customers when preparing the traditional peak demand forecasts. This approach remains supported by recent history as shown and described in the response to BCUC Supplementary IR1 3.3.

3.3 Please provide a table and a graph showing the historical UPCpeak for RS 1, RS 2, and RS 3 from 2019 to 2022.

3.3.1 Please provide a description and explanation of any observable trends.

[4] Technical Bulletin B-23-01 for a plain-language description of the building code changes.

3.3.2 If the UPCpeak has been decreasing since 2019, please provide further justification for the assumption that the UPCpeak is held constant across the planning horizon.

Response:

The following table provides the historical UPC_{peak} for RS 1, RS 2, and RS 3 from 2019 to 2022.

Table 1: Historical UPC_{peak} for RS 1, RS 2 and RS 3 (2019-2022)

ITS Historical UPC_{peak} (GJ/Hr)

Year	ITS UPC_{peak} (GJ/Hr)		
	RS 1	RS 2	RS 3
2019	0.0448	0.1918	1.9723
2020	0.0445	0.1912	1.9146
2021	0.0443	0.1905	1.9227
2022	0.0445	0.1944	1.9758

The figures provided in the response to BCUC IR1 5.3 have been extended below to include historical UPC_{peak} information for 2020 through 2022 and indicate the following results for the UPC_{peak}:

- Values for RS 1, 2 and 3 have remained relatively flat over the last five years;
- Each rate class showed an increase from 2021 to 2022;
- RS 2 and RS 3 showed a net increase from 2019 to 2022 (1.4 percent and 0.2 percent, respectively); and
- RS 1 showed a slight net decrease between 2019 and 2022 (0.7 percent).

FEI does not have sufficient information to identify all of the factors that could influence peak demand trends or the extent of influence of any individual factor. However, FEI generally attributes the trend of steady UPC_{peak} values to continued consistency in customer usage patterns as they relate to temperature. To the extent there are changes in peak use associated with DSM and changes to building codes, they are not yet observed through the analysis of customer billing data in preparation of the UPC_{peak} values.

Figure 1: RS 1 Historical UPC_{peak}

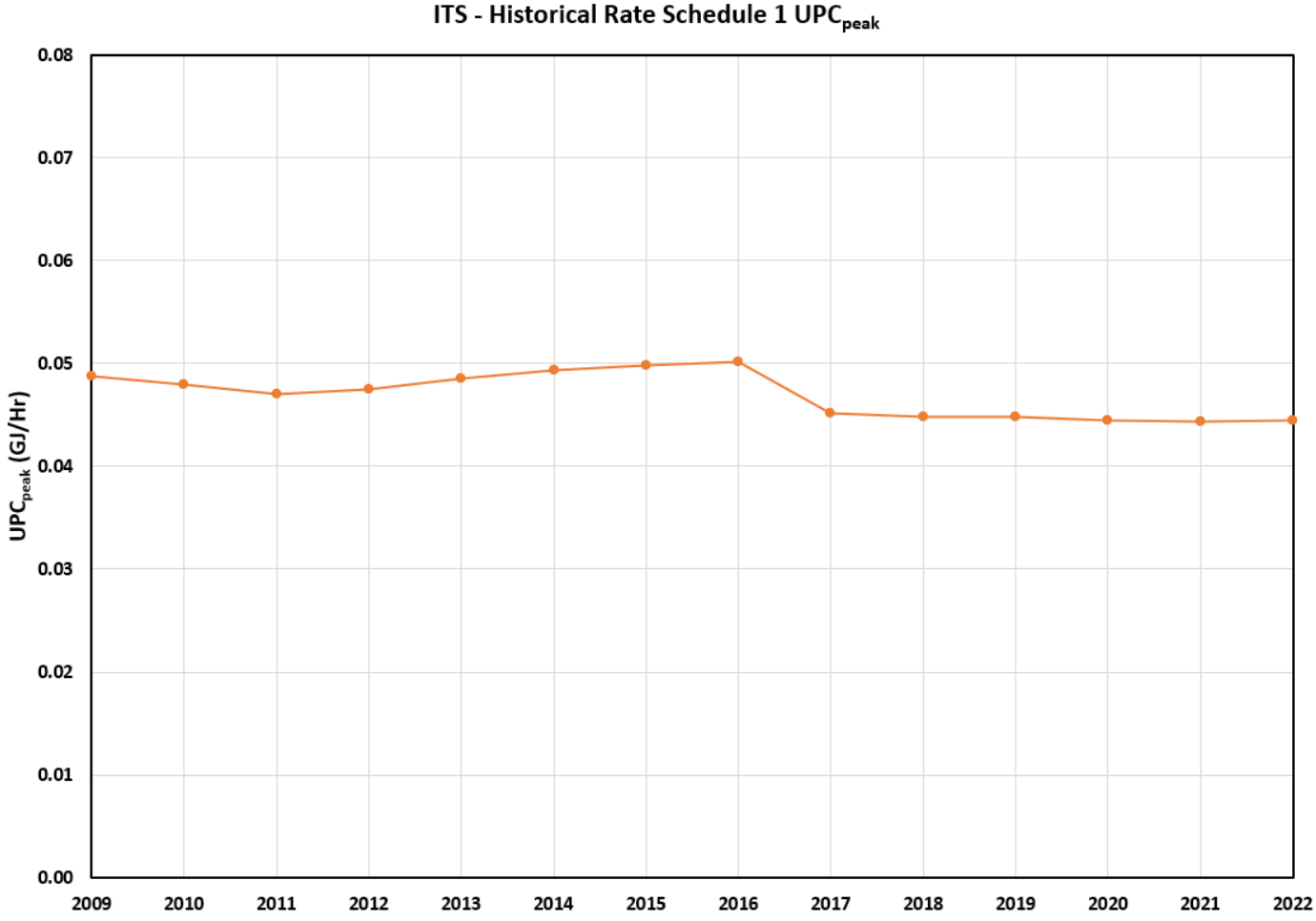


Figure 2: RS 2 Historical UPC_{peak}

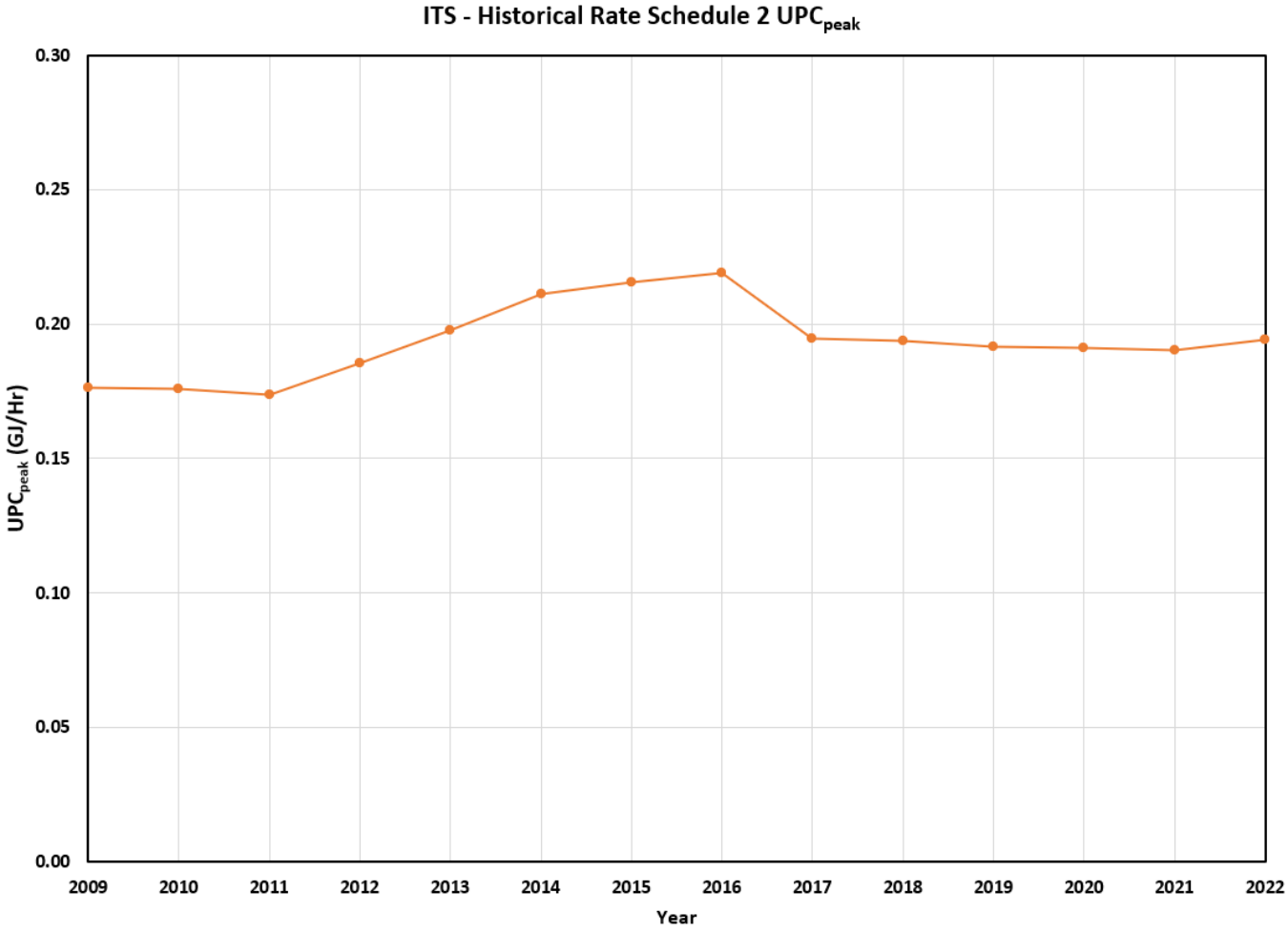
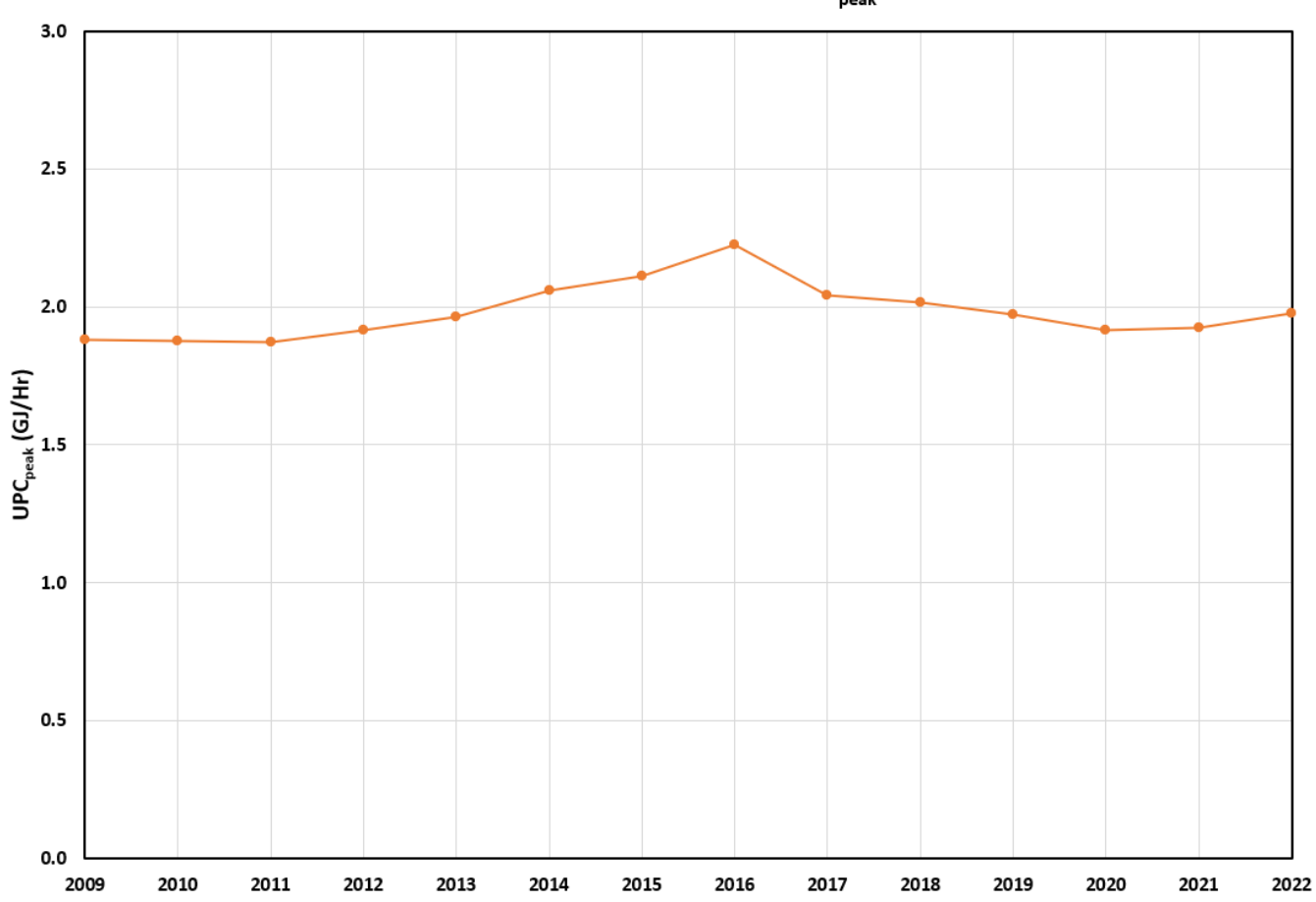


Figure 3: RS 3 Historical UPC_{peak}



3.4 Please provide a summary of specific changes being implemented by local governments in the area served by the ITS in the past two years to building codes, planning guidelines, or zoning bylaws, which would (i) prevent new natural gas connections, or (ii) limit the consumption of natural gas by a certain amount.

Response:

FEI is not aware of a local government in the ITS that has adopted a measure that would prevent new natural gas connections, further there is no existing legislative means for a municipality to restrict gas connections. FEI is aware that the City of Nelson has created an incentive approach to discourage the use of conventional natural gas. As of August 2023, builders have two choices:

they must meet Step Code 4 of the BC Energy Step Code, or Step Code 3 if they already meet the "strong" (EL3 and above) level of BC's Zero Carbon Step Code (ZCSC).

The ZCSC, which was adopted by the Province in May 2023, is a voluntary emissions reduction measure that can be adopted by local governments in conjunction with or as a standalone to the BC Step Code. The ZCSC has four levels, beginning with monitoring at EL-1, and progressing to very low levels of emissions at EL-4. At EL-4 it is not possible to install natural gas space or water heating appliances as the emissions from these appliances using conventional natural gas are too high to meet the threshold. However, at all levels of the ZCSC, ancillary appliances such as cooktops/dryers, outdoor appliances such as barbeques and patio heaters, and fireplaces are permitted as their use does not result in emissions levels exceeding the threshold. Therefore, the ZCSC does not prevent connections, but it will result in lower overall gas consumption.

However, it is important to note that under FEI's proposal in the Renewable Gas Comprehensive Review application, all new residential connections would receive 100 percent renewable gas; therefore, all levels of the ZCSC (EL1-4) can be met (including the use of space and water heating). As such, there would be no impact to volumes of gas or peak load.

With regard to the BC Energy Step Code, the following municipalities in the ITS area have adopted at least one of the levels of the BC Energy Step Code:

- City of Castlegar
- District of Coldstream
- Town of Creston
- City of Enderby
- City of Kamloops
- City of Kelowna
- District of Lake Country
- Village of Lumby
- City of Nelson
- Town of Oliver
- District of Peachland
- City of Penticton
- City of Rossland
- City of Salmon Arm
- District of Spallumcheen

- District of Summerland
- City of Vernon
- City of West Kelowna

As the BC Energy Step Code improves building and equipment efficiency, this could reduce natural gas consumption.

3.5 Please discuss whether FEI has observed any measurable impact regarding new customer connections and/or use per customer for new customers due to the adoption of the BC Energy Step Code by the City of Kelowna, Penticton, Vernon, and any other local governments served by the ITS from 2019 to 2022.

Response:

While FEI has information on DSM incentives that it has processed related to the BC Energy Step Code and believes these measures have had some impact on annual and peak use per customer[5], FEI does not have sufficient information about all of the energy choices made by energy consumers during the past few years to separate the impact of these influences on actual changes in customer connections and use per customer from other influences such as (but not limited to) the COVID-19 pandemic, the growing trend in more flexible work locations, and economic trends such as household income and inflation.

Please also refer to the response to BCUC Supplementary IR1 3.7 for a discussion of how the current trends and impacts from policy changes are captured in FEI's calculation of the UPC_{peak}.

3.6 Please explain whether FEI has taken into account the effect of the implementation of the BC Energy Step Code by local governments in the ITS system from 2019 to 2022 in its 2022 peak demand forecast.

3.6.1 If not, please also describe the expected impact (directional and order of magnitude) of the known implementation of the BC Energy Step Code by local governments in the ITS system upon future peak demand.

[5] See FEI's Annual DSM Reports for further information on the impacts of DSM incentives on customer demand at: https://www.fortisbc.com/about-us/corporate-information/regulatory-affairs/our-gas-utility/gas-bcuc-submissions/fortisbc-energy-inc.-gas-submissions/C-DS-EM/annual-dsm-reports.

Response:

The BC Energy Step Code measures implemented from 2019 to 2022 that may have impacted peak demand during the winters of 2018-2019, 2019-2020 and 2020-2021 are inherent in the data used to develop the 2022 peak demand forecast and thus have been taken into account. FEI expects that these influences during the first few years of implementing the code, which for Step 3 was voluntary for municipalities during this time, will have been small but will slowly grow over time as new construction and building retrofits that occur subsequent to the code coming into effect, slowly make up a greater proportion of customers. By being inherent in the data used to develop future peak demand forecasts and UPC values, FEI will be able to incorporate changes in energy use as they occur into its planning processes.

3.7 Please discuss the extent to which FEI considers the effect of recent requirements of the BC Energy Step Code (i.e. targeting new construction to be 20% more energy efficient that is applicable province wide including Kelowna, Penticton, and Vernon) in the UPCpeak of FEI's new customers in the 2022 peak demand forecast.

Response:

FEI considers that the requirements of Step 3 of the BC Energy Step Code, which became a requirement across the Province on May 1, 2023, can be met with the installation of high efficiency gas equipment and building envelope solutions. Further, customers who implement greater than 100 percent efficiency electric heating equipment may choose to also install secondary gas heating equipment as a back-up system. Both cases will increase the overall peak demand on the system.

To ensure current trends and impacts from policy changes are captured, FEI refreshes its UPC_{peak} values for its customers each year based on the most recently available customer information. To the extent factors like the requirements of the BC Energy Step Code are influencing customer demand, they would be captured in the assessment of UPC_{peak} over time as building stock is replaced and improved. The UPC_{peak} values for 2019-2022 are listed in the table in the response to BCUC Supplementary IR1 3.3 and show marginal changes over the past three years.

3.7.1 Please discuss the extent to which FEI considers the implementation of a 20% more energy-efficient new construction requirement will affect (i) the percentage of new customers connecting to the gas system, and (ii) for new customers that connect to the gas system, the peak demand for those customers compared to the average UPCpeak.

Response:

FEI provides the following response for each sub-topic included in this request:

i. FEI interprets the phrase "percentage of new customers connecting to the gas system" to mean the market share of new buildings that connect to the gas system compared to those that connect only to the electric system for all energy needs. FEI does not anticipate a significant change in the proportion of new construction customers connecting to FEI's ITS as a result of the mandatory Step Code requirements implemented by the Province on May 1, 2023 since the higher efficiency threshold can be met with a combination of high efficiency gas equipment and building envelope measures and, as explained in the response to BCUC Supplementary IR1 3.4, a number of municipalities in the area served by the OCU Project had already voluntarily adopted higher Step Code requirements prior to the May 1 deadline.

ii. While FEI does anticipate that new customers added to the system will continue to have a lower annual use per customer compared to the average annual use per customer on the ITS as a result of the increased efficiency requirements, FEI reiterates that the relationship between the installation of higher efficiency measures and changes to peak demand trends remains unclear. As explained in the response to BCUC Supplementary IR1 3.3, data resulting from energy use on the ITS where a number of municipalities have voluntarily implemented higher steps of the Step Code over the past few years are not thus far resulting in a discernable decrease in UPC_{peak}.

3.8 Please explain the expected impact upon the peak demand forecast if assumptions were included to adjust the UPCpeak for new customers and new customer additions in these municipalities in line with recent requirements in BC Energy Step Code.

Response:

Please refer to the response to BCUC Supplementary IR1 3.7.

3.9 Since this proceeding was adjourned, please provide an update on any work FEI has undertaken with respect to understanding the impacts of its DSM programs upon the peak demand forecast.

Response:

Since the adjournment (i.e., February 2022), FEI has undertaken the following with respect to understanding the impact of DSM on its customers' peak demand:

- Incorporated one more winter of energy consumption data into its traditional peak demand forecast so that the impact of additional, actual DSM activity in the area is incorporated into the forecast.
- Advanced the implementation of its AMI program, which FEI anticipates will provide improved data about energy use trends related to temperature (and thus more information related to peak demand trends). FEI does not expect this data to be available until it has compiled one to two complete winter seasons of data capture following the implementation of the AMI program. Further, additional studies such as customer surveys on energy use, equipment and behavior may also be needed to more fully assess the data being gathered with respect to peak demand from the AMI program.
- On July 12, 2023, FEI filed its 2024-2027 DSM Expenditures Plan with the BCUC, which includes a greater emphasis on building envelope measures, greater than 100 percent efficient gas measures, and dual fuel heating systems.

These actions and considerations have not caused FEI to change its positions as noted in the IR responses cited in the above preamble.

3.9.1 Please provide a comparison of the forecasted energy and peak demand savings from DSM in the ITS service area in the next five years and compare these savings to the previous five years. Please include a discussion of any notable trends, and the expected impact on UPCpeak.

Response:

FEI cannot complete this request with respect to peak demand savings from DSM since, as discussed in the responses to BCUC IR1 5.2 and 5.2.1, BCUC IR2 42.2, 42.2.1, 42.4.1, 42.5.1 and 44.5, and in the 2022 LTGRP[6], FEI does not have the required actual data with which to

[6] 2022 Long Term Gas Resource Plan, Section 5.5, page 5-40 and Section 7.2, page 7-9, Lines 14-21.

better analyze and understand the overall impact of DSM programs on peak demand. FEI instead incorporates the actual impacts of DSM into the peak demand forecast by updating the forecast annually with the most recent winter peak demand information available to the System Planning group.

FEI provides the following comparison of actual annual demand and annual DSM savings for the past five years (2018 – 2022) as well as forecast annual demand and forecast annual demand savings from DSM for the next five years in the Southern Interior region of the FEI service area as prepared for the 2022 LTGRP. FEI notes that there are some differences in the communities included within the Southern Interior region used to forecast demand and DSM savings for the 2022 LTGRP and the communities served by the ITS, however these differences are small and FEI considers the data provided here for the Southern Interior Region to be representative of the ITS service region. FEI also notes that both the ITS service region and the Southern Interior region are larger than the area served by the proposed OCU Project. The information below also includes the actual (past five years) and estimated (next five years including 2023) savings from the top 10 measures.

Finally, because the different data sources and analysis available to FEI to develop its response to this IR were originally developed for different purposes than to compare actual versus forecast pre- and post-DSM demand for a specific portion of FEI's service area and were developed at different times, the information is not easily combined into a single table or chart. For example, actual DSM savings were prepared as part of the DSM Annual Report and tracking and are as recent as year-end 2022, whereas estimated future DSM savings as presented in the LTGRP were prepared months earlier. It is also not easy to compare actual demand before DSM to the forecast of pre- and post-DSM demand due to the influences of factors other than the availability and uptake of DSM measures on actual demand.

Figure 1: Historic Actual Annual Energy Demand (Excluding Low Carbon Transportation Demand) in the Southern Interior Region – All Sectors Combined

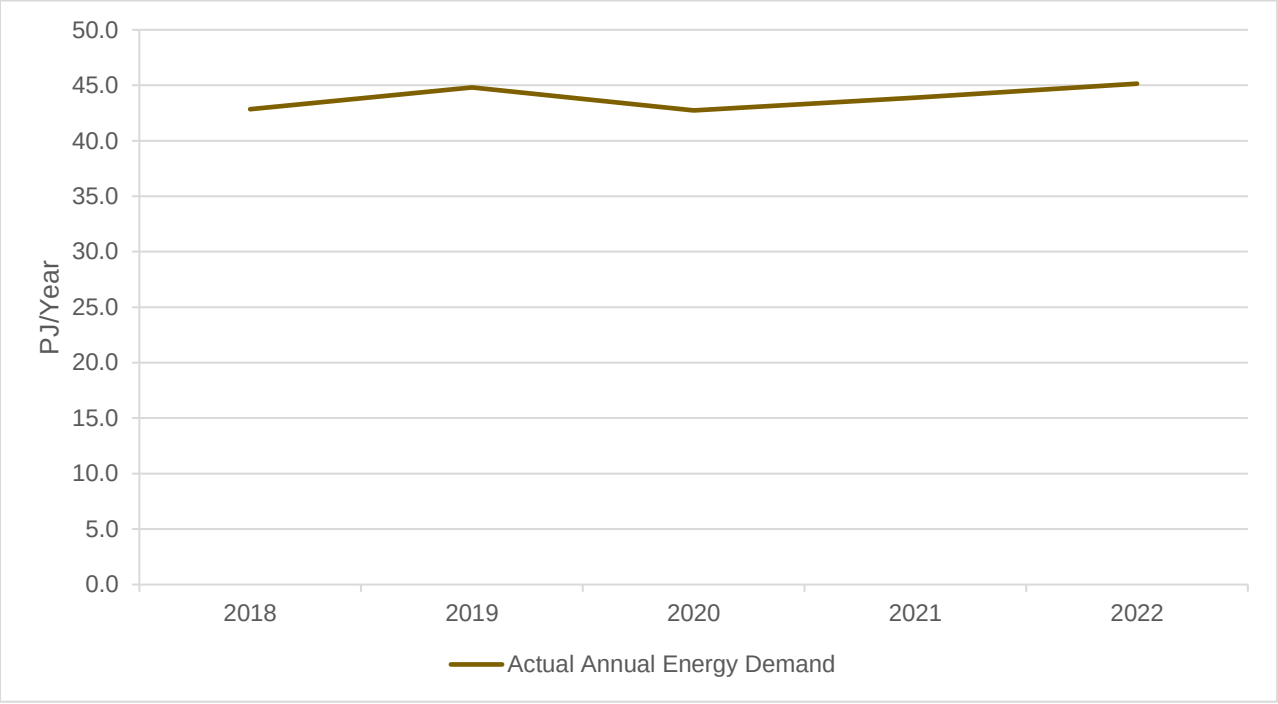


Figure 2: Actual DSM Savings (Excluding LCT) in the Southern Interior Region – All Sectors Combined

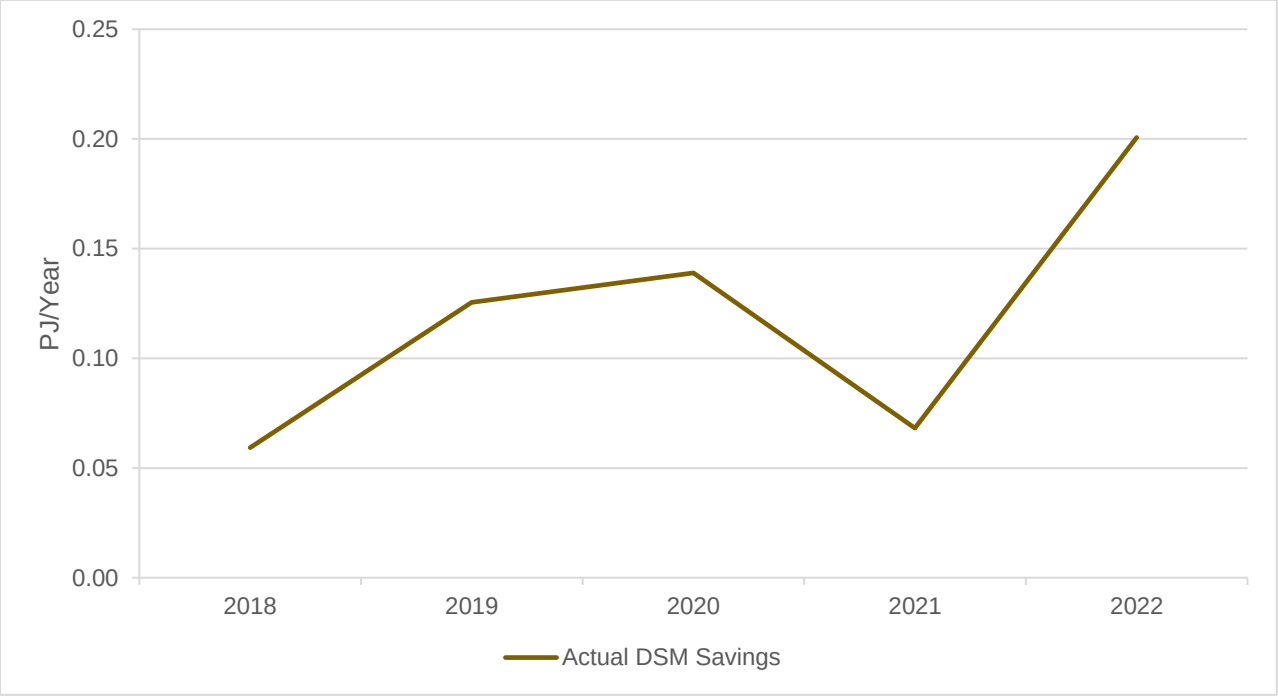


Table 1: Actual 2018-2022 Cumulative Savings from Top 10 DSM Measures

Measure Name	Cumulative Savings
ENERGY STAR Furnace	0.06
Commercial Boiler	0.06
Furnace	0.03
Technology Implementation In-Service Date Payment	0.03
Adwest Regenerative Thermal Oxidizer - Post Completion	0.03
" Pipe Insulation - >1"" HW Pipe"	0.03
EnerChoice Fireplace	0.03
ECM 1: Continuous Dry Kiln (Post-Completion)	0.02
Steam Boiler	0.02
Post Implementation Capital Incentive	0.02

Figure 3: Forecast Annual Demand Before and After Estimated High DSM Savings (Excluding LCT) in the Southern Interior Region – All Sectors Combined

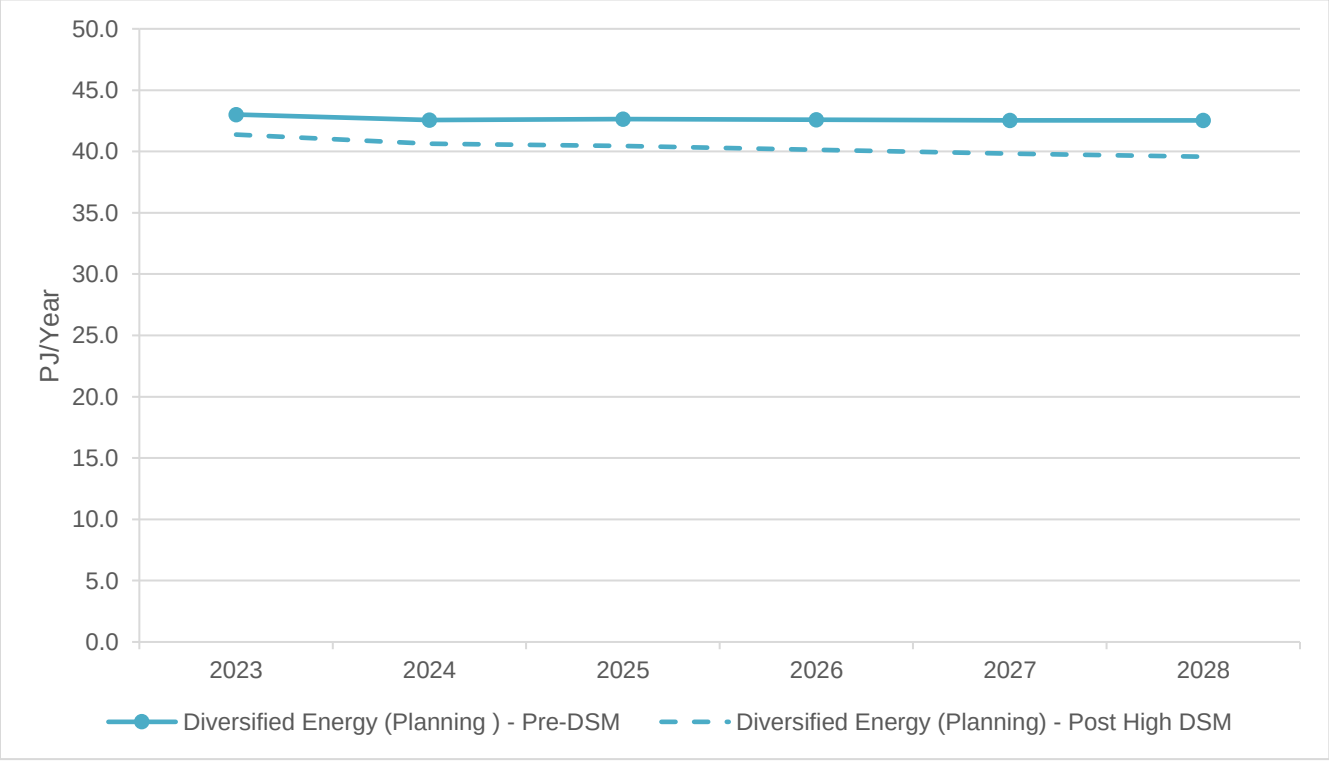


Figure 4: Diversified Energy (Planning) Estimated High DSM Savings Potential (Excluding LCT) in the Southern Interior Region – All Sectors Combined

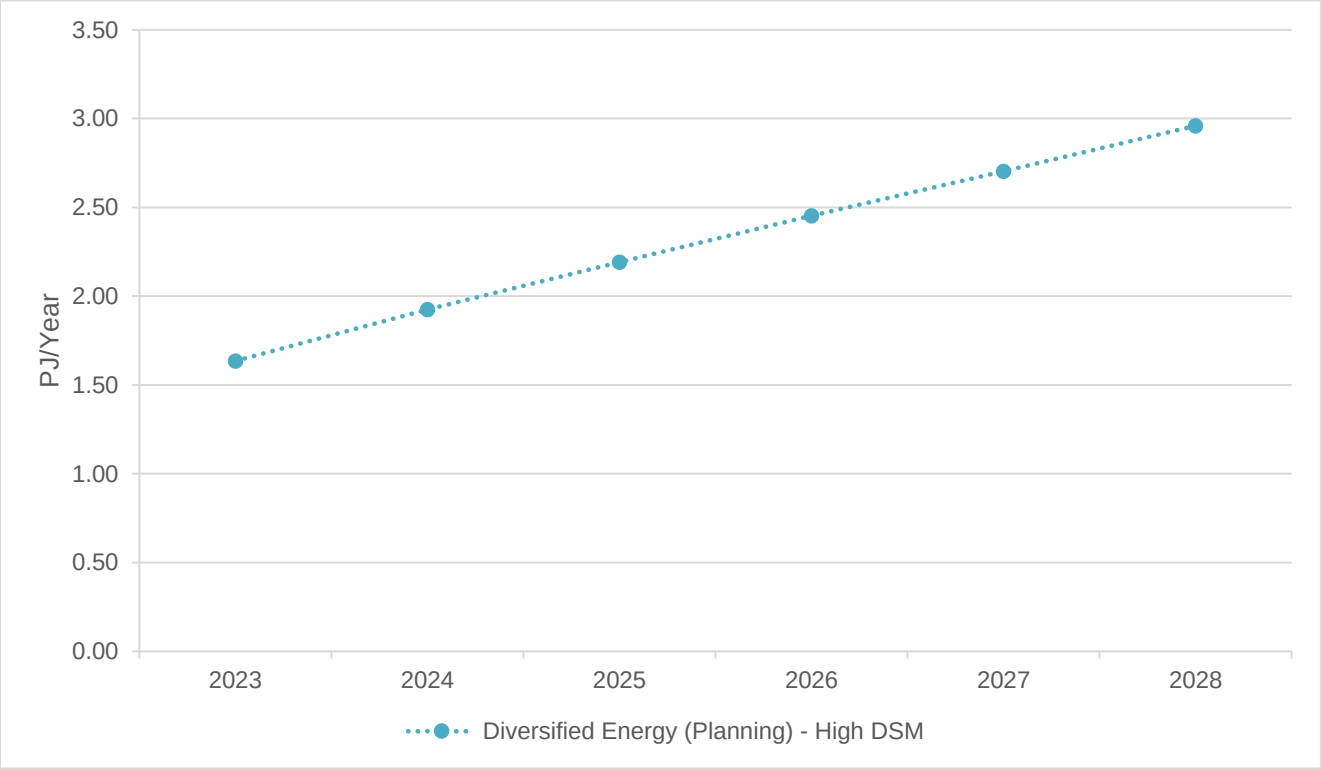


Table 2: Estimated 2023-2028 Cumulative Savings from Top 10 DSM Measures as presented in the 2022 LTGRP

Measure Name	Cumulative Savings
High-Efficiency (ENERGY STAR) Condensing Gas Tankless Water Heater - Mature Market Costs	0.78
Drain Water Heat Recovery	0.76
Communicating Thermostat	0.48
HVAC Zoning (HVAC Zone Control)	0.43
Low Flow Showerhead	0.29
Heat Transfer Tech	0.28
Energy Management	0.28
Advanced Thermostat	0.25
High Quality Furnace Installation - ENERGY STAR Verified	0.22
GHP - Combi	0.21

3.10 Please summarize FEI's plans regarding demand response natural gas solutions, including the progress of pilot projects implemented to date, and future timelines.

3.10.1 Please discuss whether FEI anticipates being able to implement demand response programs targeting deferral of capital investments in the next 5 to 10 years.

Response:

FEI has completed a pre-feasibility study in Q1 2023 to assess various commercially available gas demand response (DR) solutions that could potentially reduce the system peak impacts to FEI's gas system. Three solutions were identified as potentially feasible:

- Residential smart thermostat DR programs;
- Residential water heater control DR programs; and
- Large commercial and industrial performance-based gas DR programs.

FEI is currently developing a business case to conduct a gas DR pilot focused on residential customers. Should the business case show favourable potential for gas peak mitigation, FEI intends to conduct customer recruitment in late 2023 and 2024 and run the pilot beginning in 2024 for one year. The pilot results would be evaluated soon after, with final results expected to be available in late 2025.

If the pilot results show cost-effective peak mitigation, FEI would evaluate the potential for a more permanent gas DR program thereafter. Until the pilot is evaluated, FEI cannot speculate whether it will be able to implement a gas demand response program targeting deferral of capital investments in the next 5 to 10 years.

4.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-2, BCUC IR 8.4; Exhibit B-14, BCUC IR 43.3; Exhibit B-20, PIB IR 18; Exhibit B- 24, RCIA IR 49

Design Degree Day (DDD)

In response to BCUC IR 8.4, FEI mentioned:

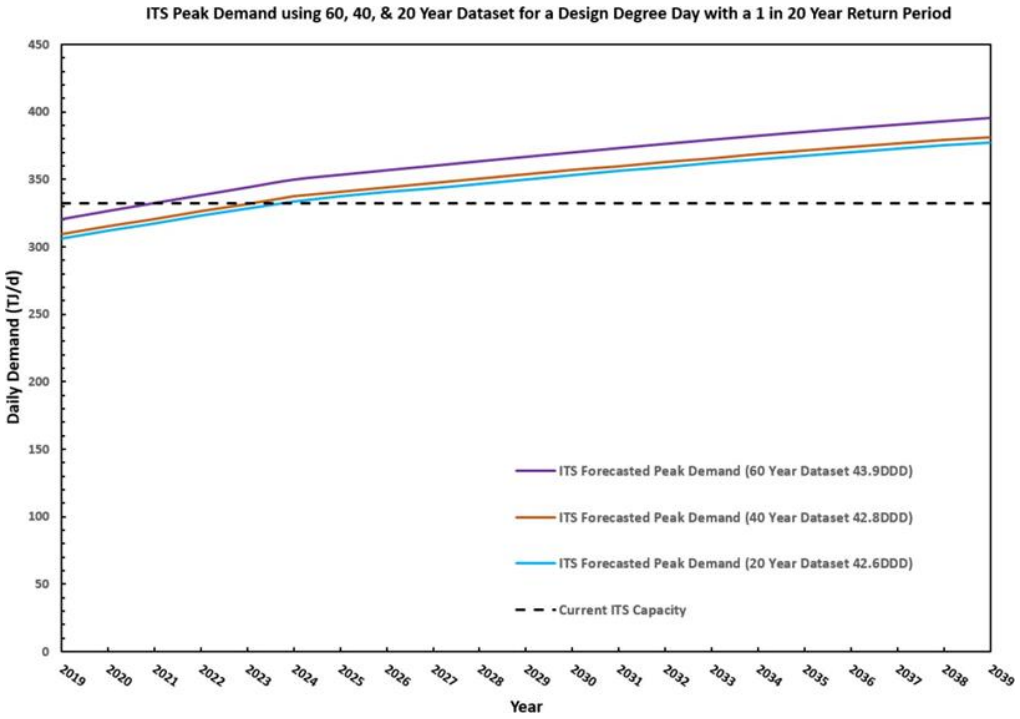
> FEI last updated the DDD for each of the 22 weather zones in its operating territory in 2017. These updates examined the weather history in each weather zone over the preceding 60 years. The last update resulted in a warming in the DDD temperature in most weather zones. For example, in the case of the north and central Okanagan, the DDD changed from a 45.0-degree day to a 43.9-degree day. This represented a warming of 1.1°C in the design temperature. The Thompson region DDD warmed by 2.2°C and the South Okanagan by 0.9°C. This results in lower peak demand estimates for customers in these regions than would have been calculated using the DDD values in use prior to 2017.

In response to BCUC IR 43.3, FEI provided a table showing DDD using 40 and 20-year datasets:

Design Degree Day 20 year return period with Various Historical Datasets

Weather Area	Zone Name	Existing DDD 60 Year Dataset	DDD 40 Year Dataset	DDD 20 Year Dataset
YLW	Kelowna	43.9	42.8	42.6
YKA	Kamloops	46.7	43.4	42.6
YYF	Penticton	39.1	37.5	35.7
YCG	Castlegar	39.7	36.2	35.9

And based on these different datasets, FEI provided a reproduced 2019 peak demand forecast:



In response to BCUC IR 43.4, FEI provided a table of the coldest and second coldest days for regions served by the ITS:

Table of Coldest and Second Coldest day for Regions Served by the ITS

Zone	Winter 2016-17		Winter 2017-18		Winter 2018-19		Winter 2019-20		Winter 2020-21	
	Temp (°C)	Date	Temp (°C)	Date	Temp (°C)	Date	Temp (°C)	Date	Temp (°C)	Date
Thompson	-19.6/-19.6	Jan 11/Jan 12	-16.9/-16.1	Dec 24/Jan 1	-17.7/-16.1	Feb 5/Feb 10	-21.3/-21.2	Jan 15/Jan 14	-16.4/-15.8	Feb 11/Feb 12
North/CentralOkanagan	-17.8/-17.8	Jan 11/Jan 12	-13.6/-13.3	Feb 21/Dec 24	-15.8/-14.3	Feb 5/Feb 10	-18.9/-18.2	Jan 14/Jan 13	-14.2/-14.1	Feb 12/Feb 11
South Okanagan	-14.4/-13.3	Jan 13/ Jan 12	-11.8/-12.3	Dec 24/Feb 20	-12.4/-11.8	Feb 4/Feb 5	-14.2/-14	Jan 15/Jan 14	-12.4/-11.5	Feb 11/Feb 12
West Kootenay	-12.3/-12.3	Jan 11/Jan 5	-12/-11.2	Feb 19/Feb 23*	-10.9/-10.7	Feb 7/Feb 6	-12.1/-11	Jan 14/jan15	-11.8/-10.5	Feb 12/Feb 9**

*Dec 24 - 5th coldest day

**Feb 11 - 3rd coldest day

4.1 Please confirm whether FEI used the same DDD as in 2017 for all the regions in ITS for the 2022 peak demand forecast.

4.1.1 If yes, please explain why FEI did not update the DDD. Please discuss how the DDD and peak demand would change if more up to date datasets were used.

4.1.2 If not confirmed, please provide an update on the DDD that was used for the 2022 peak demand forecast. Please also discuss the impact of using updated DDD upon the 2022 peak demand forecast.

Response:

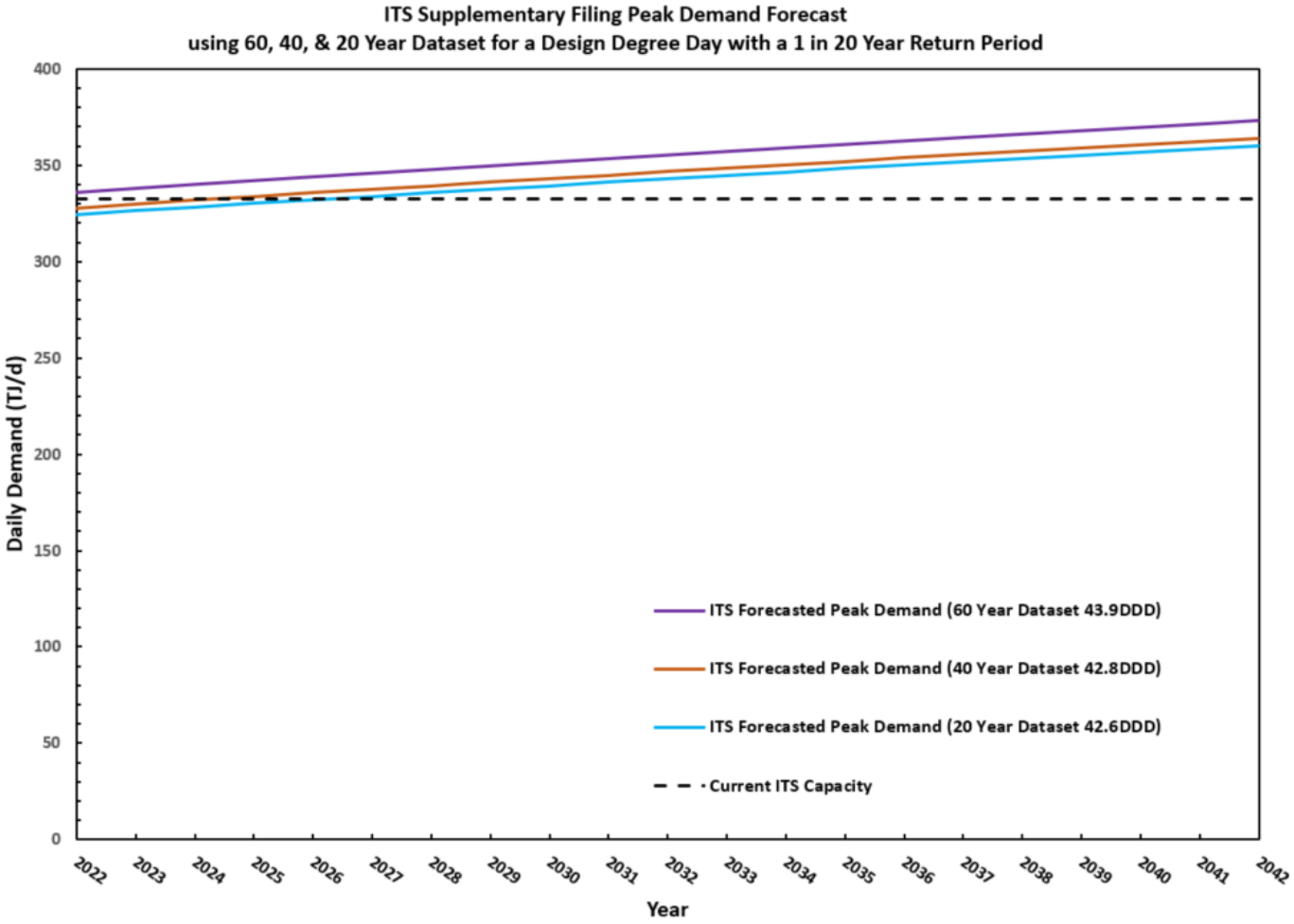
Confirmed. It is FEI's practice to update Design Degree Day values every 10 years to provide consistency in forecasting, as discussed in the response to BCUC IR1 8.2.1. The previous update was in 2017 and the next update will be in 2027.

The use of more up to date datasets would capture more recent weather extremes. This could result in an increase in the DDD if new extremes (e.g., December 22, 2022 extreme weather event) are realized in the return period which could result in an increased peak demand for a given area; alternatively, the result could be a decrease if an extreme weather event which occurred at the end of the 60-year period (i.e., the oldest historical data point) is removed from the dataset.

4.2 Please reproduce the graph from BCUC IR 43.3, as shown in the preamble, for the 2022 peak demand forecast, using 60, 40, and 20-year datasets on the DDD. Please use the same datasets that were used for the 2022 peak demand forecast. Additionally, please provide the comparison in a table format.

Response:

FEI clarifies that the figure from the response to BCUC IR2 43.3 referenced in this IR was provided in the response to BCUC IR2 43.3.1. The figure from BCUC IR2 43.3.1 in the preamble has been reproduced using the Supplementary Filing Forecast and is shown below. The information is also provided in table format below.


ITS Supplementary Filing Peak Demand Forecast
using 60, 40, & 20 Year Dataset for a Design Degree Day with a 1 in 20 Year Return Period
Daily Demand (TJ/d)
400
350
300
250
200
150
100
50
0
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
Year
ITS Forecasted Peak Demand (60 Year Dataset 43.9DDD)
ITS Forecasted Peak Demand (40 Year Dataset 42.8DDD)
ITS Forecasted Peak Demand (20 Year Dataset 42.6DDD)
Current ITS Capacity

1

ITS Supplementary Filing Peak Demand Forecast using 60, 40, & 20 Year Dataset for a Design Degree Day with a 1 in 20 Year Return Period			
Year	60 Year Dataset (TJ/d)	40 Year Dataset (TJ/d)	20 Year Dataset (TJ/d)
2022	336	328	324
2023	338	330	326
2024	340	332	328
2025	342	334	330
2026	344	336	332
2027	346	338	334
2028	348	339	336
2029	350	341	338
2030	352	343	339
2031	353	345	341
2032	355	347	343
2033	357	349	345
2034	359	350	346
2035	361	352	348
2036	363	354	350
2037	364	356	352
2038	366	357	353
2039	368	359	355
2040	370	361	357
2041	371	362	358
2042	373	364	360

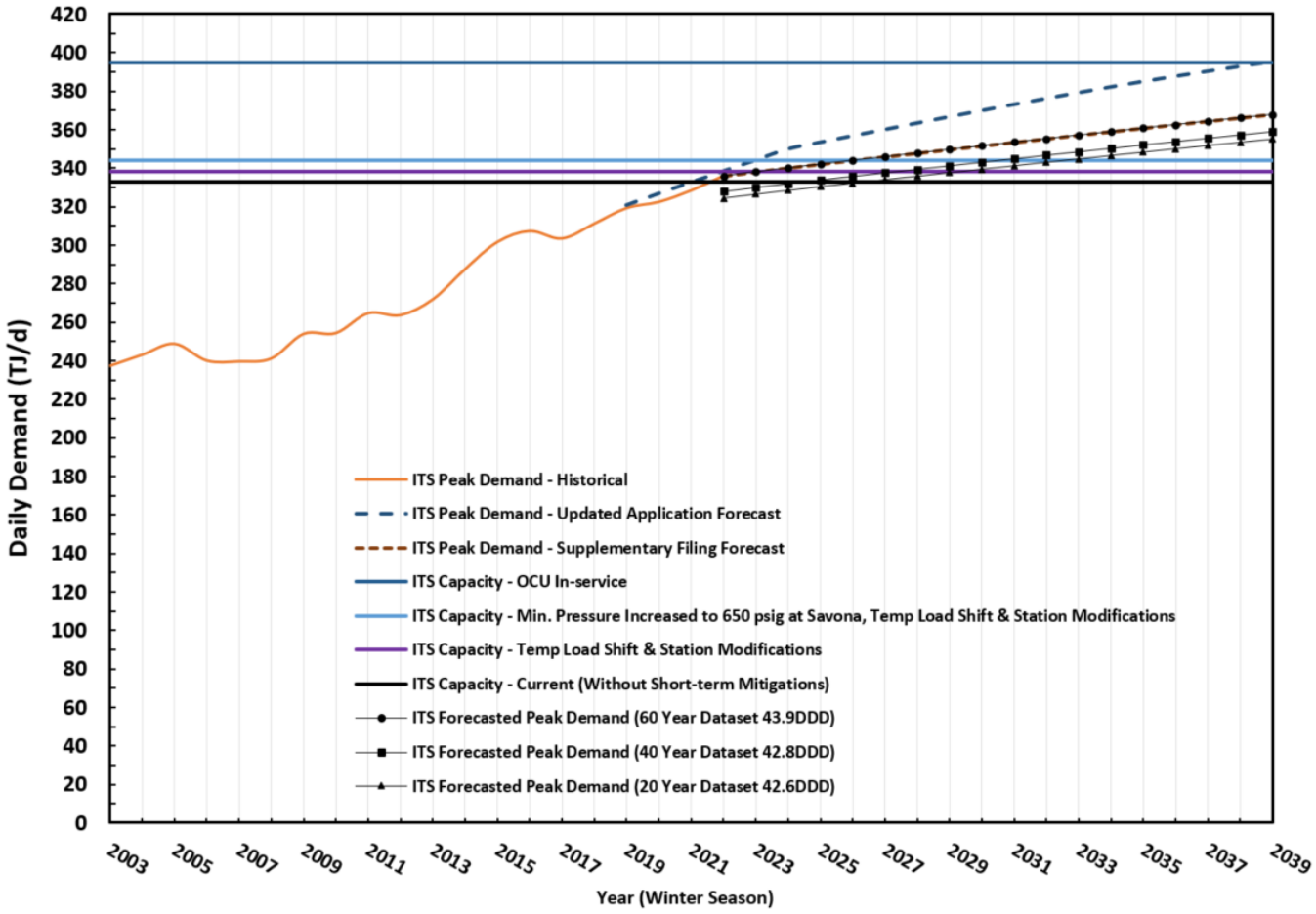
4.3 Please overlay the resulting graph of the previous question with the response for BCUC IR 71.9 above.

Response:

Subsequent to receiving these IRs, FEI sought clarification from BCUC Staff to confirm that the reference in this IR to BCUC IR 71.9 was intended to refer to BCUC Supplementary IR1 1.9.

Figure 1 below is an updated version of the figure provided in the response to BCUC Supplementary IR1 1.9 with the inclusion of the three peak demand curves from the response to BCUC Supplementary IR1 4.2.

Figure 1: Updated Figure from BCUC Supplementary IR1 1.9 including Peak Demand Curves from BCUC Supplementary IR1 4.2



4.4 Please update the table of coldest and second coldest days for regions served by ITS to include winter 2021/2022 and 2022/2023.

Response:

Please refer to Table 1 below. For clarity, the table in the preamble has been transposed and the two requested seasons of data added to the bottom.

Table 1: Coldest and Second Coldest day for Regions Served by the ITS

	Zone	Thompson	North/Central Okanagan	South Okanagan	West Kootenay
Winter 2016-17	Temp (°C)	-19.6/-19.6	-17.8/-17.8	-14.4/-13.3	-12.3/-12.3
	Date	Jan 11/Jan 12	Jan 11/Jan 12	Jan 13/ Jan 12	Jan 11/Jan 5
Winter 2017-18	Temp (°C)	-16.9/-16.1	-13.6/-13.3	-11.8/-12.3	-12/-11.2
	Date	Dec 24/Jan 1	Feb 21/Dec 24	Dec 24/Feb 20	Feb 19/Feb 23*
Winter 2018-19	Temp (°C)	-17.7/-16.1	-15.8/-14.3	-12.4/-11.8	-10.9/-10.7
	Date	Feb 5/Feb 10	Feb 5/Feb 10	Feb 4/Feb 5	Feb 7/Feb 6
Winter 2019-20	Temp (°C)	-21.3/-21.2	-18.9/-18.2	-14.2/-14	-12.1/-11
	Date	Jan 15/Jan 14	Jan 14/Jan 13	Jan 15/Jan 14	Jan 14/jan15
Winter 2020-21	Temp (°C)	-16.4/-15.8	-14.2/-14.1	-12.4/-11.5	-11.8/-10.5
	Date	Feb 11/Feb 12	Feb 12/Feb 11	Feb 11/Feb 12	Feb 12/Feb 9**
Winter 2021-22	Temp (°C)	-25/-21.9	-23.5/-19.8	-18.8/-14.9	-13.6/-13.4
	Date	Dec 27/Dec 31	Dec 27/Dec 29	Dec 27/Dec 26	Jan 1/Dec 29
Winter 2022-23	Temp (°C)	-26.3/-23.4	-24.4/-22.5	-19.6/-18	-18.6/-16
	Date	Dec 22/Dec 21	Dec 22/Dec 21	Dec 22/Dec 21	Dec 22/Dec 21

Notes to Table:
**Dec 24 - 5th coldest day*
***Feb 11 - 3rd coldest day*

In response to PIB IR 18, FEI stated:

> Should the Project not be approved, FEI would be forced to curtail firm (i.e., non interruptible) customers on the coldest winter days in the Okanagan region when the system is experiencing its peak demand.

In response to RCIA IR 49, FEI stated:

> Based on the assumption that all short-term mitigation measures continued to be applied, FEI expects that curtailment of firm customers would be required at a temperature 1.9ºC warmer than the design temperature. This would correspond to a 42DD (minus 24ºC) in the North and Central Okanagan – an event which last occurred in December 2008. The probability of this temperature occurring over the winter is calculated to be 9.5 percent and would correspond to a return period of one in 10.5 years. In other words, absent the OCU Project, there would be a one-

in-ten chance in the winter seasons after 2023/24 that there would be insufficient capacity on cold winter days to meet all customer demand.

4.5 In table format, please show at what temperature FEI would be required to curtail firm customers for each year until 2030, assuming any current or planned short-term mitigation measures continue to be implemented. Please also compare the temperatures to the DDD assumed by FEI, and estimate the probability of the temperatures occurring.

Response:

Table 1 shows the firm curtailment requirement based on the Supplementary Filing Forecast.

Table 1: Firm Curtailment Requirement Based on Supplementary Filing Peak Demand

Year	Temperature	DD	Probability of DD
2023	-25.9	43.9 (DDD)	5.0%
2024	-25.9	43.9 (DDD)	5.0%
2025	-25.9	43.9 (DDD)	5.0%
2026	-25.6	43.6	5.5%
2027	-25.3	43.3	6.1%
2028	-25.0	43.0	6.7%
2029	-24.7	42.7	7.5%
2030	-24.3	42.3	8.6%

Further, as discussed in the response to BCUC Supplementary IR1 1.4, the growth in Historic Peak Demand has kept pace with that of the Updated Application Forecast through 2022. As such, FEI also evaluated the temperature at which it would be required to curtail firm customers under the peak demand of the Updated Application Forecast and found it to be -21.3 degrees C in 2030: a 39.3 degree day. The probability of this temperature occurring in any given year is approximately 23 percent.

Annual variations in peak demand forecasts are observed and expected given the variability in customer account forecasts. To the extent future forecasts show peak demand between that of the Updated Application and the Supplementary Filing, FEI estimates the annual risk of curtailment of firm customers to be between 10 and 20 percent by 2030.

5.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1-2, Section 3.3.4; Exhibit B-2, BCUC IRs 1.2

Impact of COVID-19

On page 28 of the Updated Application, FEI mentions:

> FEI's peak demand forecast was prepared in 2019, before the onset of the COVID-19 pandemic. As of the date of filing, there is insufficient data to quantify the COVID-19 impact, to forecast its future impacts on energy consumption or, more importantly for system planning, its impact on peak loads. […]

In response to BCUC IR 1.2, FEI stated:

> FEI still has insufficient data to quantify any potential impact of the COVID-19 pandemic on peak demand forecasts. […] FEI has not received updates to these forecasts since the beginning of the pandemic. FEI has also continued to attach customers in 2020 at rates comparable to 2019 which suggests that, so far, the pandemic has not materially affected current growth rates. FEI will review and incorporate updated forecasts from the CBOC and BC Statistics when they are received and apply these updates to the forecasts prepared later in 2021.
>
> […] Therefore, FEI expects that UPCpeak will not materially increase or decrease in response to the pandemic. Any change in the new peak demand forecast would be largely due to changes in the customer account forecast driven by CBOC and HHF [household formation] growth rates that have not yet been received. [emphasis added]

5.1 Please discuss in detail whether there has been any analysis of COVID-19 impact on the UPCpeak and total peak demand since the proceeding was adjourned.

Response:

Since the proceeding was adjourned, FEI has not undertaken an analysis specifically looking at the impact of COVID-19 on UPC_{peak} or Total Peak Demand. Through FEI's annual update of customer information and customer account forecasts, the impact of the COVID-19 pandemic would have been captured in both the 2022 Peak Demand Forecast and the Supplementary Filing Forecast as they took into account year-end customer information for 2021 and 2022, respectively. As observed in Figures 2-1 and 2-2, Historic Peak Demand growth has kept pace with the Updated Application Forecast's predicted growth, falling below by at most 1.3 percent through 2020 and 2021, suggesting a limited impact from COVID-19 on customer growth and natural gas consumption in the ITS.

5.2 Please confirm, or explain otherwise, that FEI has taken into account the impact of the COVID-19 pandemic in its 2022 peak demand forecast.

Response:

Please refer to the response to BCUC Supplementary IR1 5.1.

5.3 Please provide an update on the impact of new CBOC and HHF growth rate upon the 2022 peak demand forecast.

Response:

Figures 1 and 2 below compare the original and updated CBOC Housing Starts growth rates forecasts for single-family dwellings (SFD) and multi-family dwellings (MFD). The CBOC forecast only impacts residential customer additions, and those additions remain positive for the duration of the forecast period.

Both updated forecasts show an expected early decline in housing starts and the decline is more pronounced in the SFD forecast. However, beyond 2030, the updated forecasts for both housing types are more closely aligned.

FEI also notes that after 2020, the trends are generally similar between the original CBOC forecast and the updated CBOC forecast, with the updated forecast slightly more positive after 2030. FEI notes that the relationship of the CBOC forecast to peak demand is not very direct and so a difference of this magnitude is not likely to have a material impact on peak demand.

Figure 1: Original and Updated CBOC Forecasts for Single-Family Dwellings (SFD)

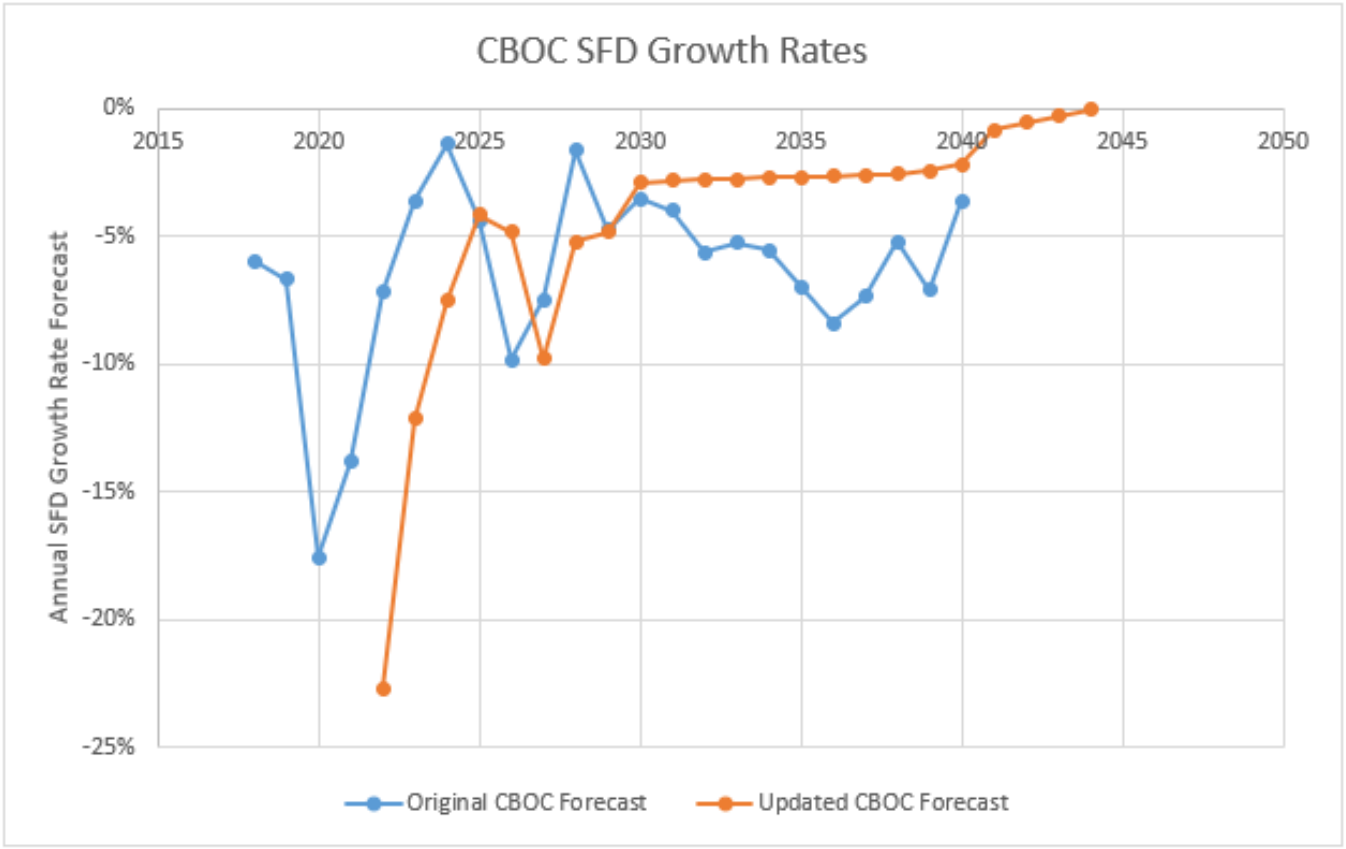


Figure 2: Original and Updated CBOC Forecasts for Multi-Family Dwellings (MFD)

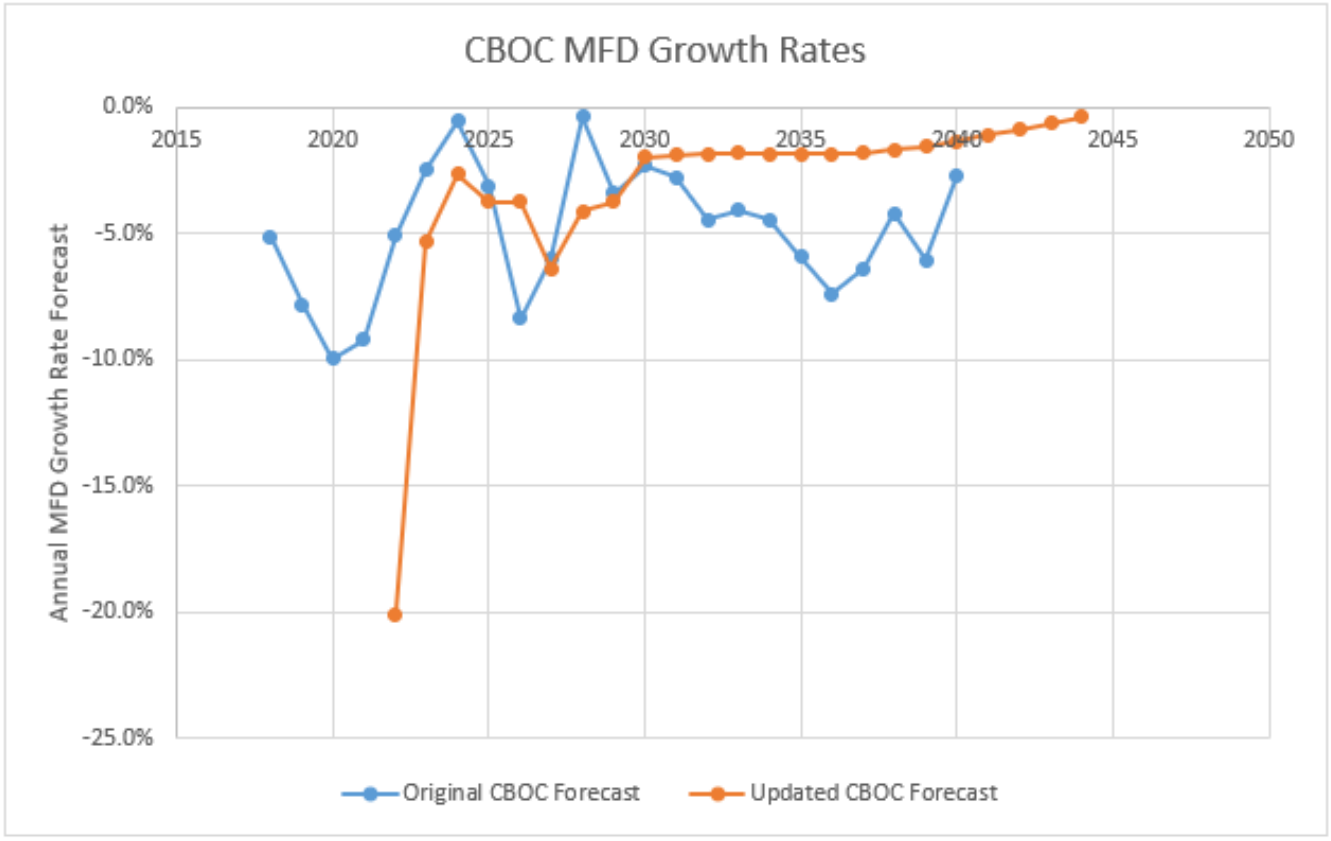
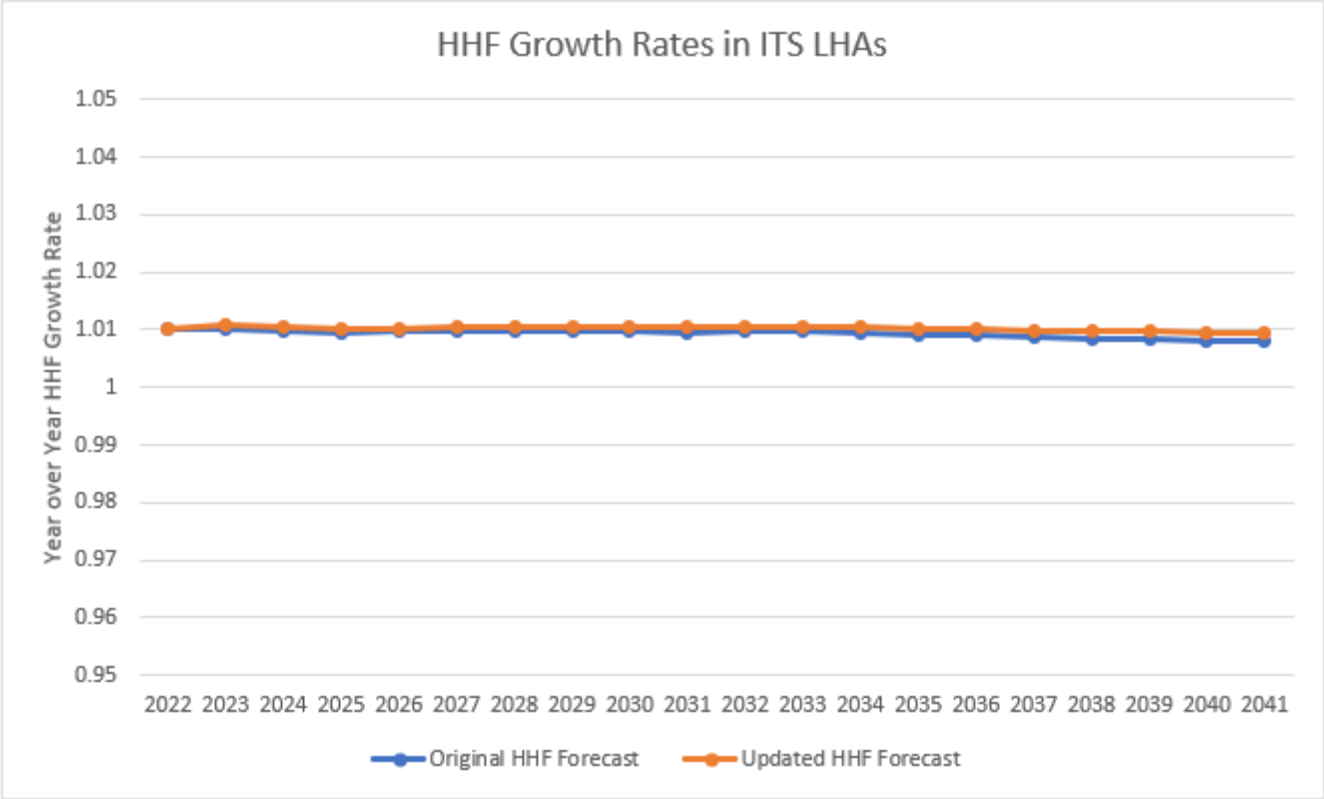


Figure 3 below shows the year-over-year Household Formations (HHF) growth rates from both the original HHF forecast and the most recent update, aggregated for the local health areas (LHAs) serviced by the ITS. The figure shows that the two forecasts are very similar, and FEI expects the update has negligible impacts on the peak forecast.

1 **Figure 3: Original and Updated Household Formations (HHF) Growth Rate Forecasts**



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6.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-25, p. 2; Exhibit B-2, BCUC IRs 2.2, 2.4, 2.5, 2.6.1, 2.7, 2.7.1

Inlet Pressure at Gate Stations

On page 6 of the Supplementary Filing, FEI states:

> Figures 2-1 and 2-2 above also show that demand is forecast to exceed the ITS capacity with short-term mitigation measures in place, resulting in an expected capacity shortfall. With the temporary load shifting and station modification measures in place, a capacity shortfall is expected this winter (i.e., Winter 2023-24), as shown by the intersection of the Supplementary Filing Forecast line and the line titled "ITS Capacity – Temp Load Shift & Station Modifications". [Emphasis Added]

In response to BCUC IR 2.2, FEI stated:

> In the past ten years, FEI has not experienced inlet pressures below the minimum 350 psig at the inlet to the major gate stations on the ITS during periods of high system demand when this low pressure would cause a concern for maintaining supply to the downstream system. FEI has therefore not experienced any impacts upon downstream systems.

In response to BCUC IR 2.4, FEI stated:

> […] future increases in demand will reduce the inlet pressure at gate stations throughout the system. […]

In response to BCUC IR 2.5, FEI stated and showed graphs:

> Figure 1 below shows the station inlet pressure of major ITS gate stations from 2019 to 2024 under forecast peak day conditions in the absence of the OCU Project. Figure 2 shows the minor improvement that would result from increasing the Savona tap pressure from 600 psig to 650 psig in 2022 to offset the pressure decay for a period of time. Beyond 2024, the hydraulic model no longer converges, which indicates that the system would effectively collapse to zero pressure under the sustained peak day load.
>
> In the forecast period starting from 2020, the inlet pressure at Polson Gate will fall below the minimum design pressure of 350 psig and would continue to decay in the absence of the OCU Project. FEI will apply short-term mitigation measures to ensure the downstream systems are able to continue to operate safely and reliably until the completion of the OCU Project.

The rate of pressure decay illustrates the limited timeframe FEI has to implement mitigation measures before a critical point is reached. The pressure decay becomes more pronounced each year as the decay is nonlinear, and hence accelerates as the pressure declines.

Fig. 1 Major Gate Station Inlet Pressure - Peak Day 2019-2024

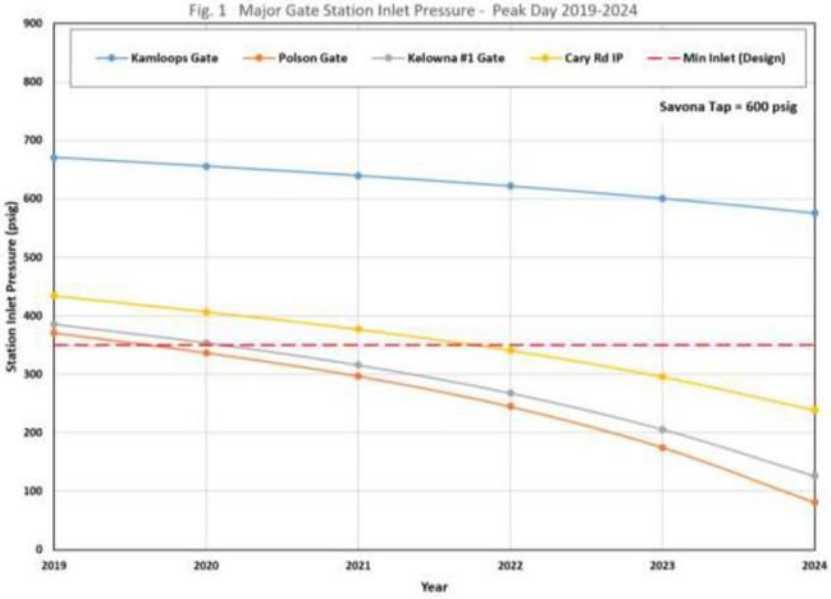
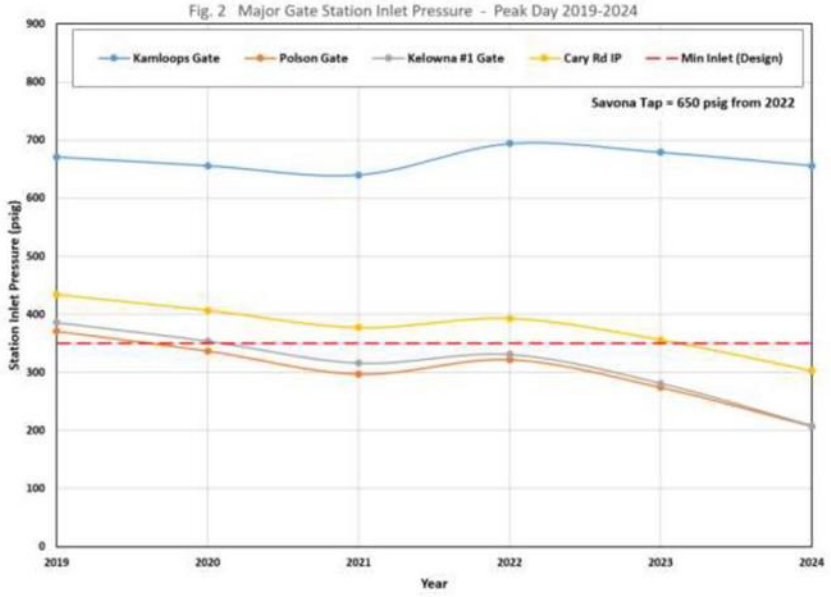


Fig. 2 Major Gate Station Inlet Pressure - Peak Day 2019-2024



In response to BCUC IR 2.6.1, FEI stated:

> The capacity shortfall at a local level could be managed in two ways: by supplementing the supply deficit locally with compressed natural gas (CNG) or

liquefied natural gas (LNG), or by curtailing local load to match the available supply.

CNG/LNG Supply Augmentation

As explained in the response to BCUC IR1 2.6, the communities of West Kelowna, Lavington, and Lumby are just the first communities that would be impacted. As such, when considering a localized CNG/LNG solution, initially at least two locations would need to be addressed, one on the West Kelowna IP system and another on the Polson IP system serving both Lavington and Lumby. […]

Customer Load Curtailment

Curtailing customer load locally to address the supply deficit caused by the capacity shortfall is not considered viable by FEI and would have similar increasing requirements as those described above. FEI does not consider it appropriate to design or operate its system by relying on the curtailment of firm customers to maintain the required minimum system pressures. […]

In response to BCUC IR 2.7 and 2.7.1, FEI showed tables of the year major gate stations would fall below 350 psig under peak day conditions.

Gate Station	Year Winter Peak Day Pressure < 350 psig	Winter Peak Day Mitigation Measures Insufficient	Customers Served (currently)
Polson Gate	Winter 2020-21	Winter 2023-24	2,000
Kelowna #1 Gate	Winter 2020-21	Winter 2023-24	16,300
Cary Road Gate	Winter 2022-23	Winter 2023-24	9,000

Gate Station	Year Winter Peak Day Pressure < 350 psig	Customers Served (currently)
Polson Gate	Winter 2037-38	2,000

6.1 Please discuss whether FEI has experienced pressures below the minimum 350 psig at the inlet of the major gate stations to date.

6.1.1 If so, please explain the consequences and actions taken by FEI.

Response:

To date, FEI has not experienced pressures below 350 psig at the major gate stations referenced in the preamble to this IR. Starting in the Winter of 2022/23, FEI began enacting temporary mitigation measures as detailed in the response to BCUC Supplementary IR1 9.1. Additionally,

FEI requested increased pressure from WEI when required since 2020, which contributes to higher pressure at the inlet of the major gate stations during periods of peak demand.

6.2 Please provide historical peak day pressure readings at the inlet of major gate stations and at the Savona compressor station from 2020 to 2023 in a graph and table format.

Response:

Please see the figures and tables provided below. FEI interprets the request for the Savona compressor station as being the suction pressure at the FEI Savona compressor station.

Figure 1 and Table 1 show the minimum pressure readings that occurred on each peak winter day.

Figure 2 and Table 2 show the daily average pressure on those days.

Figure 1: Recorded Minimum Pressure Readings on Winter Season Peak Days

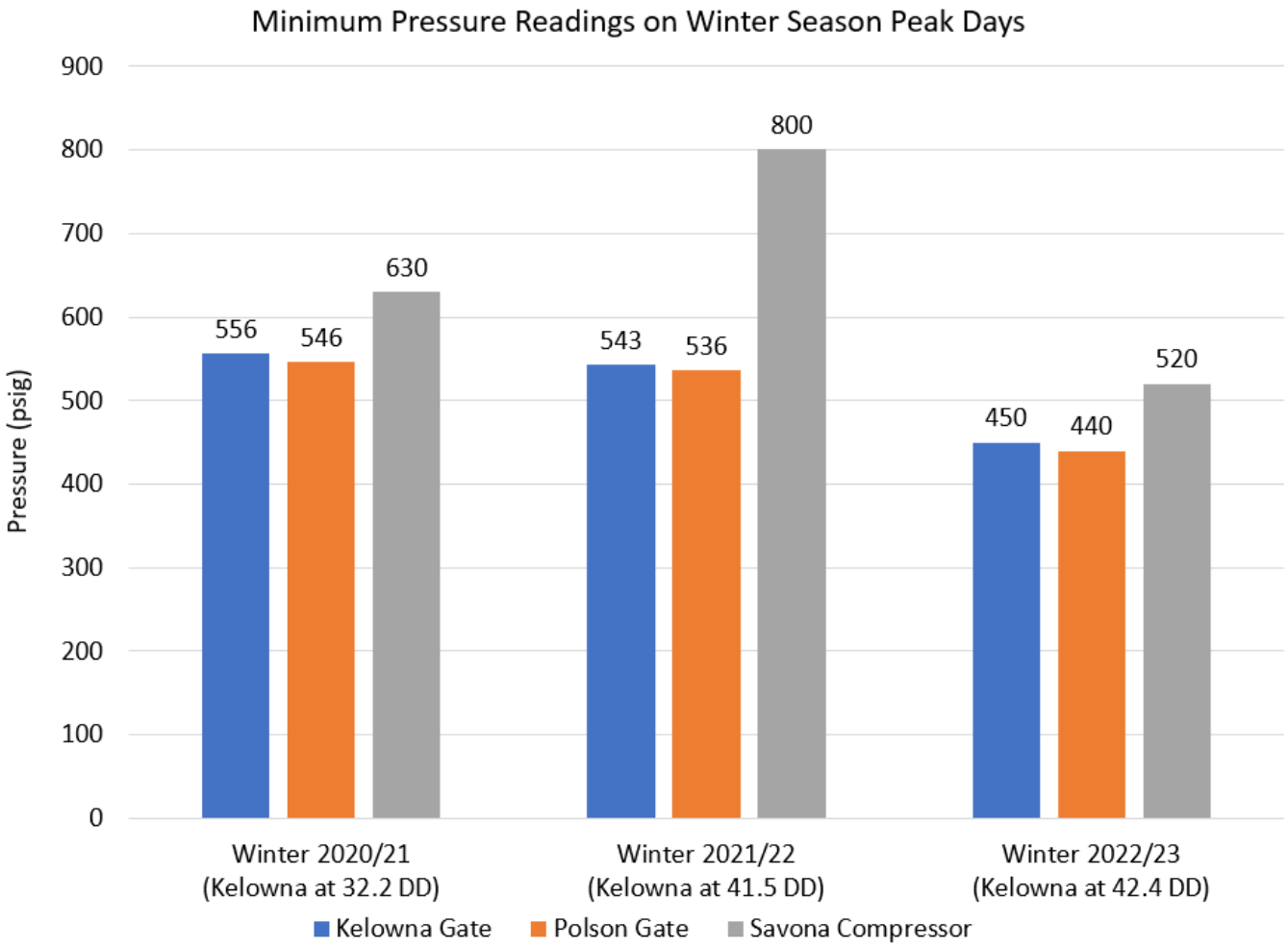


Table 1: Recorded Minimum Pressure Readings on Winter Season Peak Days

Season	Date	Kelowna Weather Station	Minimum Station Inlet Pressure (psig)		
			Kelowna Gate	Polson Gate	Savona Compressor
Winter 2020-2021	2/11/2021	-14.2°C (32.2 DD)	556	546	630
Winter 2021-2022	12/27/2021	-23.5°C (41.5 DD)	543	536	800
Winter 2022-2023	12/22/2022	-24.4°C (42.4 DD)	450	440	520[7]

[7] The minimum inlet pressure reading reported at the Savona Compressor station occurred overnight. WEI provided inlet pressures higher than 600 psi when requested during peak hour flows to ensure FEI was able to serve customers, per the best-effort agreement discussed in the responses to the BCUC Supplementary IR1 10 series.

Figure 2: Average Minimum Pressure Readings on Winter Season Peak Days

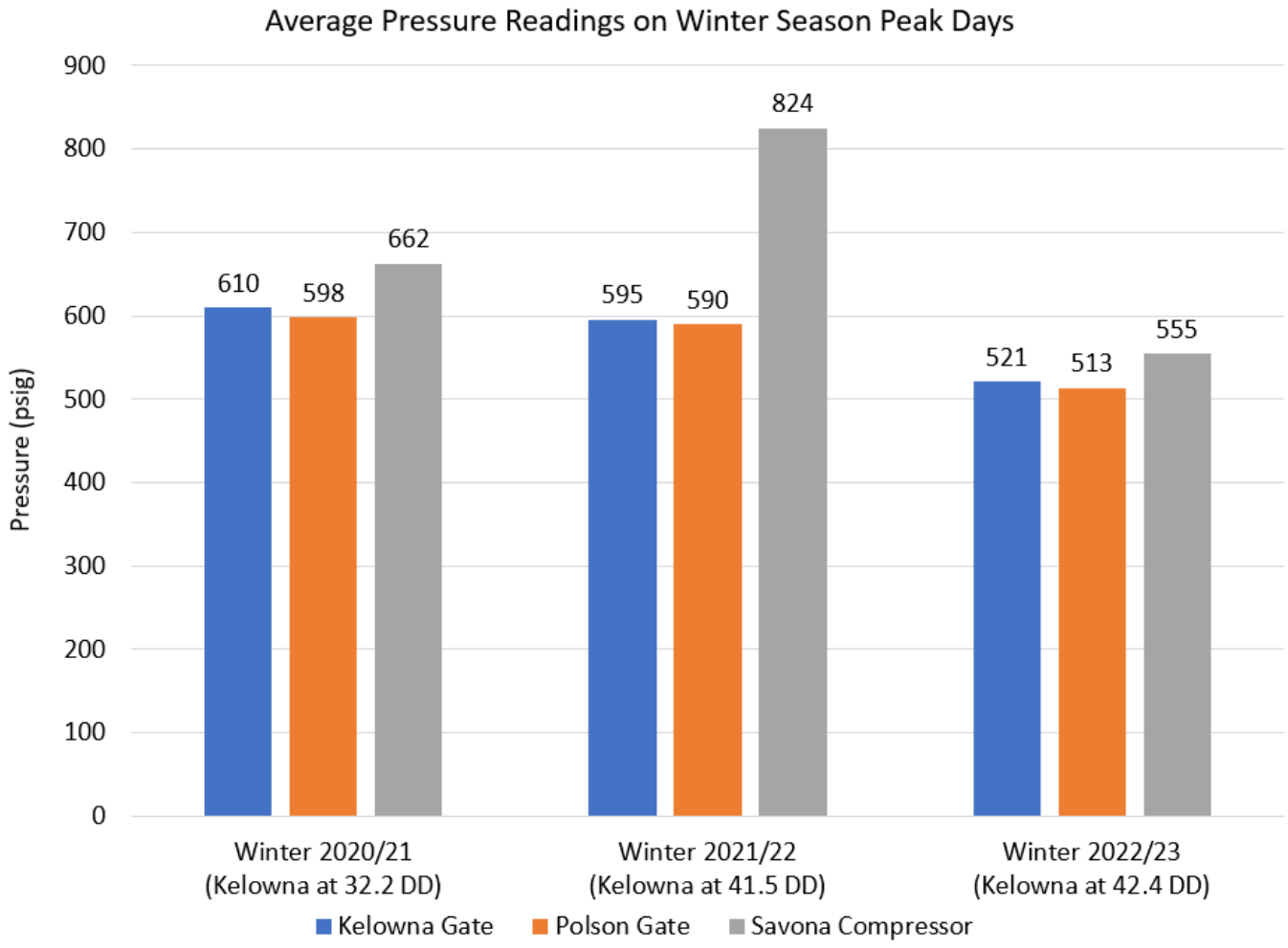


Table 2: Average Pressure Readings on Winter Season Peak Days

Season	Date	Kelowna Weather Station	Average Station Inlet Pressure (psig)		
			Kelowna Gate	Polson Gate	Savona Compressor
Winter 2020-2021	2/11/2021	-14.2°C (32.2 DD)	610	598	662
Winter 2021-2022	12/27/2021	-23.5°C (41.5 DD)	595	590	824
Winter 2022-2023	12/22/2022	-24.4°C (42.4 DD)	521	513	555

6.3 Please provide updated graphs of station inlet pressure of major ITS gate stations from 2022 to 2039 under peak day conditions in the 2022 peak demand forecast,

in the absence of the OCU Project, with and without increased Savona tap pressure.

Response:

The following figures are updated versions of Figures 1 and 2 provided in the response to BCUC IR1 2.5 (as shown in the preamble), analyzed with the Supplementary Filing Forecast. FEI is unable to provide data beyond 2026, as when the pressures get that low, the simulations no longer produce rational pressure results or feasible solutions.

Fig. 1 Major Gate Station Inlet Pressure - Peak Day 2022-2025

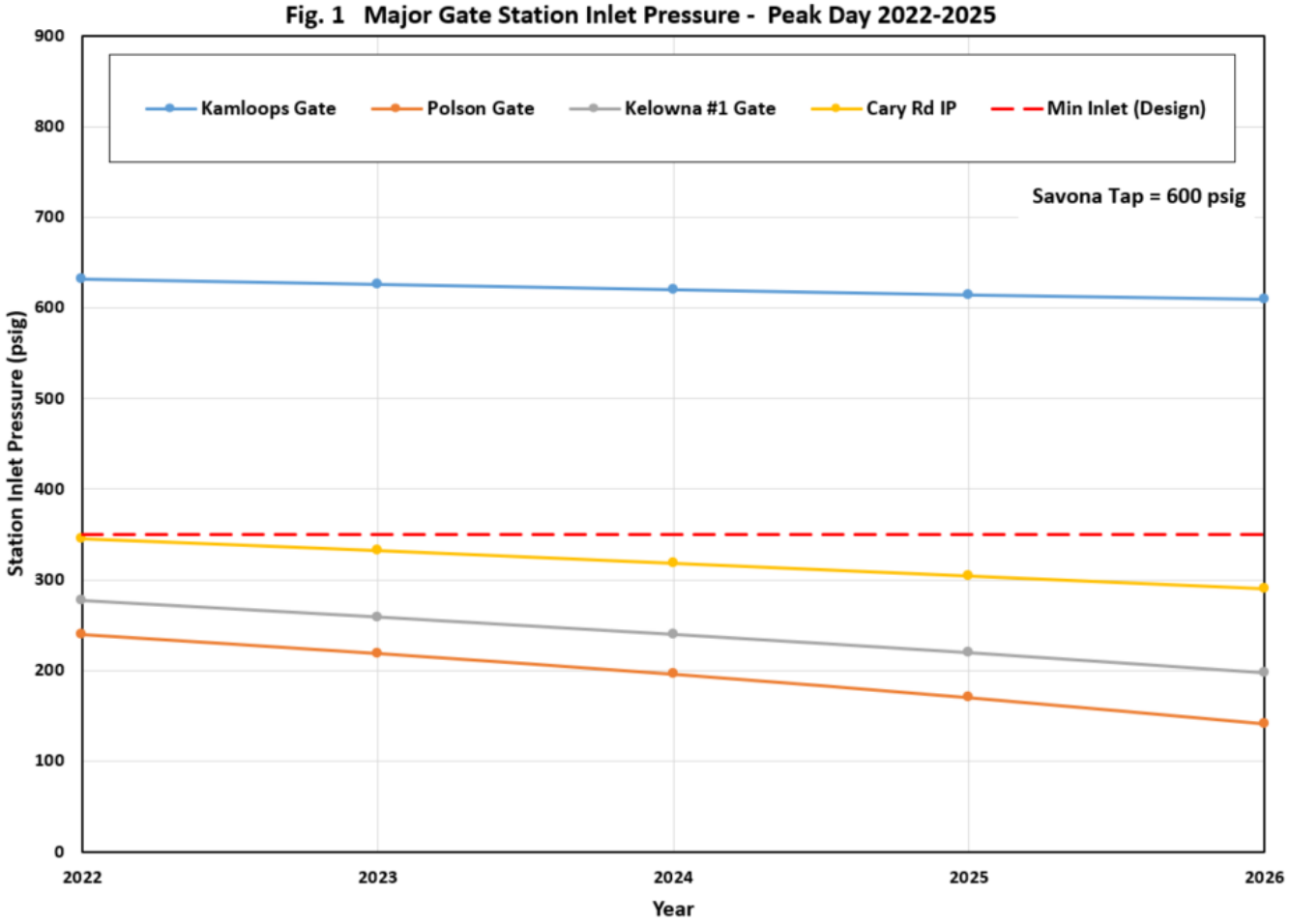
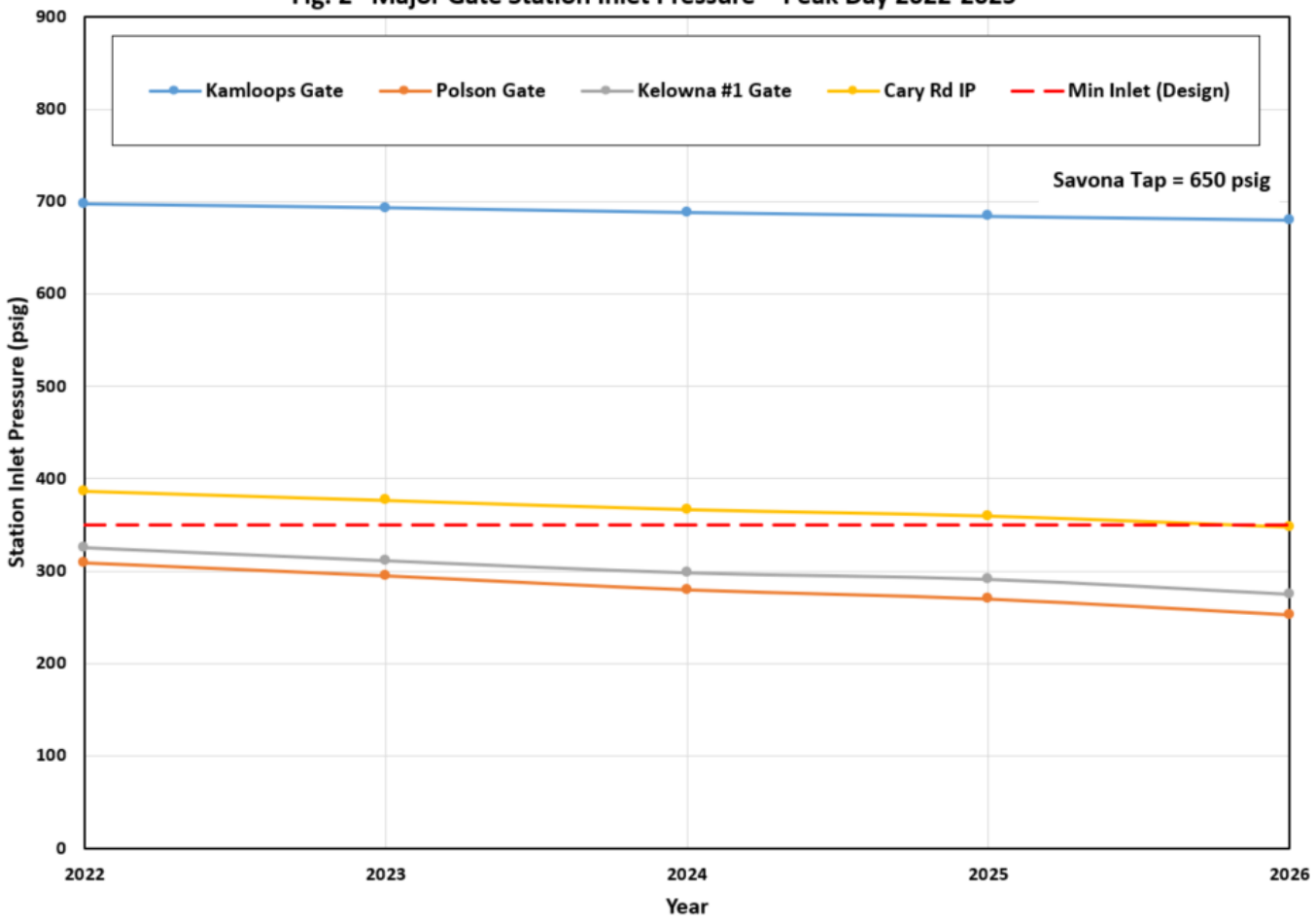


Fig. 2 Major Gate Station Inlet Pressure - Peak Day 2022-2025



6.4 Please update the tables in the preamble for the 2022 peak demand forecast.

Response:

The following Tables 1 and 2 update the tables provided in response to BCUC IR1 2.7 and 2.7.1 based on the Supplementary Filing Demand Forecast.

Table 1: Updated Table to BCUC IR 1 2.7

Gate Station	Winter Peak Day Pressure < 350 psig	Winter Peak Day Mitigation Measures Insufficient	Customers Served (currently)
Polson Gate	Winter 2022-23	Winter 2025-26	2,100
Kelowna #1 Gate	Winter 2022-23	Winter 2025-26	17,900
Cary Road Gate	Winter 2022-23	N/A	9,000

Table 2: Updated Table to BCUC IR 1 2.7.1

Gate Station	Year Winter Peak Day Pressure < 350 psig	Customers Served (currently)
Polson Gate	Winter 2050-51	2,100

6.5 Please confirm whether the expected capacity shortfall in winter 2023/24 is anticipated to occur in the communities of West Kelowna, Lavington, and/or Lumby only.

6.5.1 If confirmed, please explain what measures FEI has undertaken to manage this expected shortfall.

6.5.2 If not confirmed, please discuss the capacity shortfall along other areas of the ITS system such as Greater Kelowna, Lake Country, Vernon, and Coldstream, and what measures FEI has undertaken to manage this shortfall.

Response:

FEI confirms that absent mitigation measures, a capacity shortfall in 2023/24 is anticipated and would be realized at West Kelowna, Lavington and Lumby. The shortfall would be expected to be observed at the tail ends of the distribution networks for those communities only.

To manage the expected shortfall in the short-term, FEI plans to employ mitigation measures such as load shifting and station modifications at the Polson IP and Kelowna IP stations.

As system load increases in subsequent years, absent the OCU Project, the severity of potential impacts will increase, affecting increasingly larger areas of the ITS. The extent of the impact will depend on where and how much load materializes during peak periods.

6.6 Please discuss whether FEI has undertaken or plans to undertake any CNG/LNG supply augmentation or customer load curtailment in the communities of West Kelowna, Lavington, and Lumby.

Response:

FEI has not undertaken nor plans to undertake CNG/LNG augmentation. Please refer to the response to BCUC Supplementary IR1 10.3 and BCUC IR2 48.1 for more information.

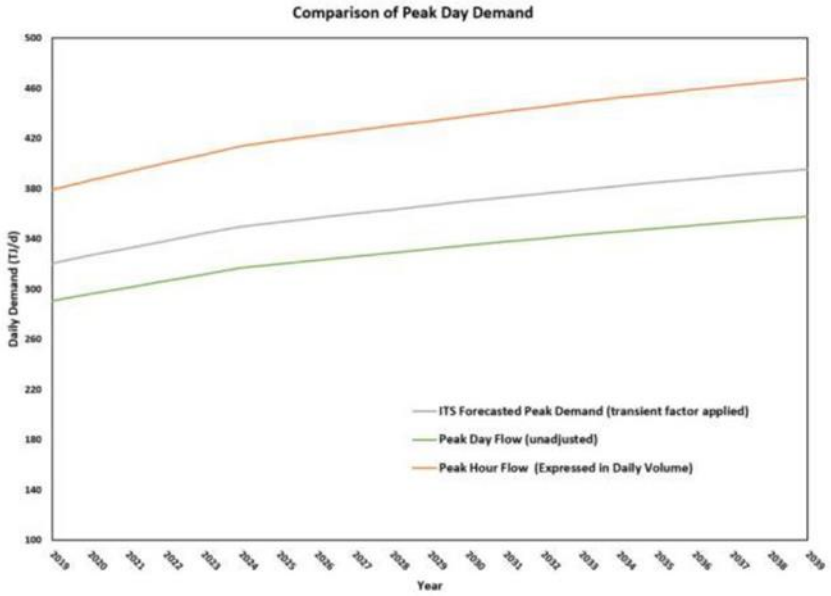
Due to the other short-term mitigation measures available to FEI, there is currently no plan to undertake load curtailment in West Kelowna, Lavington, or Lumby as this is not yet necessary. Please refer to the response to BCUC Supplementary IR1 10.2 for information on when strategic curtailment would be required.

7.0 Reference: PROJECT NEED AND JUSTIFICATION

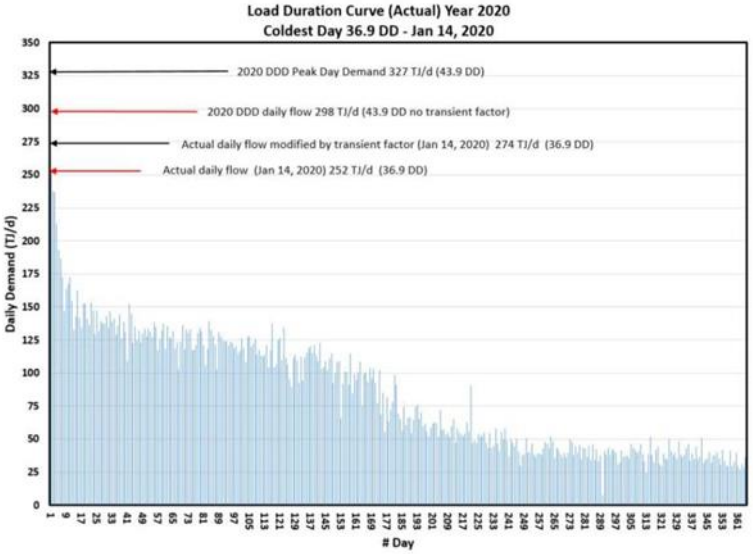
Exhibit B-2, BCUC IR 3.1.2, 3.3.1

Line Pack

In response to BCUC IR 3.1.2, FEI showed a comparison between the peak day forecast for the transient factor adjusted and the unadjusted peak day forecast.



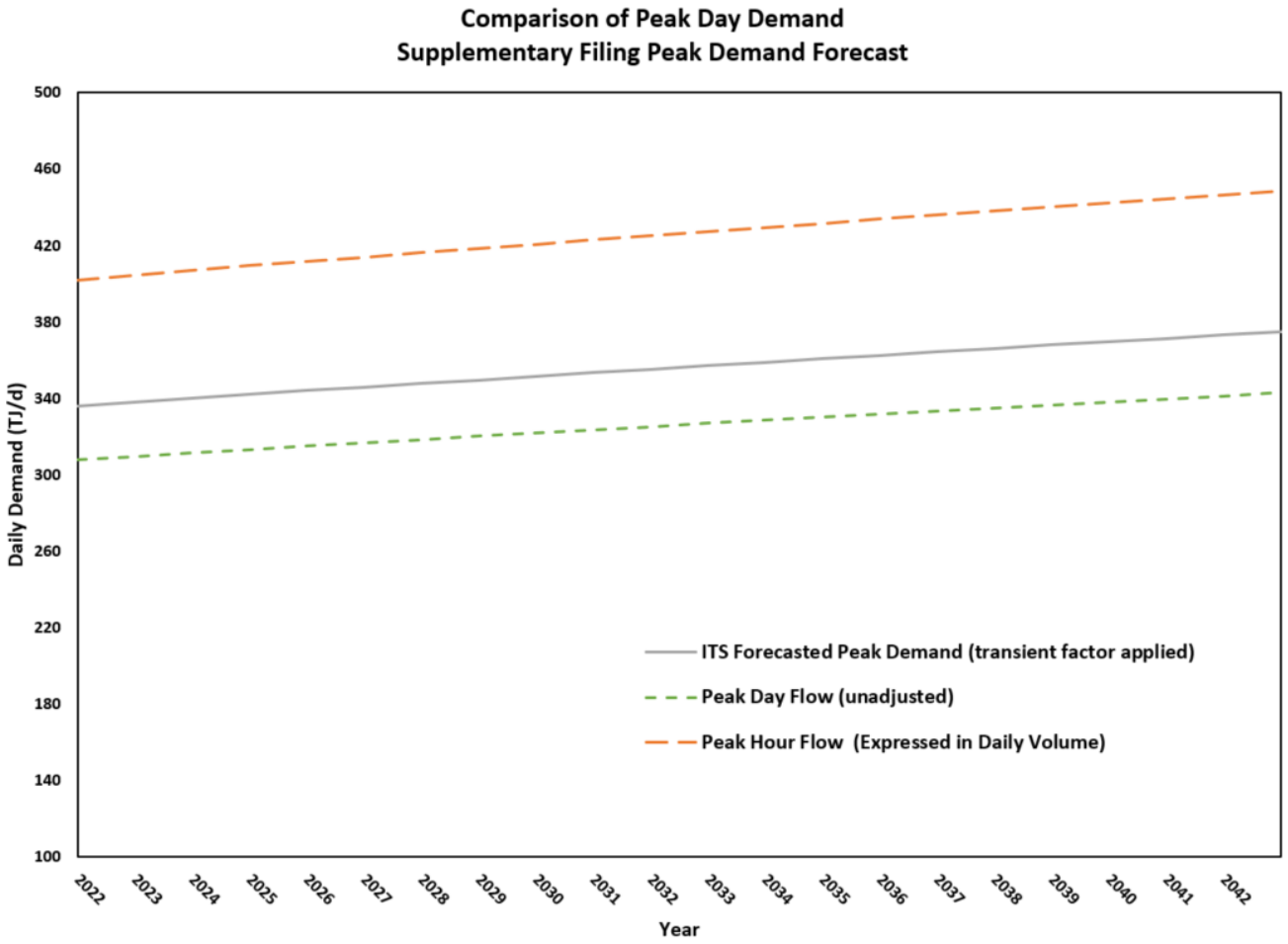
In response to BCUC IR 3.3.1, FEI provided a load duration curve showing daily peak demand with the coldest day observed in the last five years.



7.1 Please update the graph of the comparison of peak day demand with the adjusted transient factor and unadjusted transient factor for the 2022 peak demand forecast.

Response:

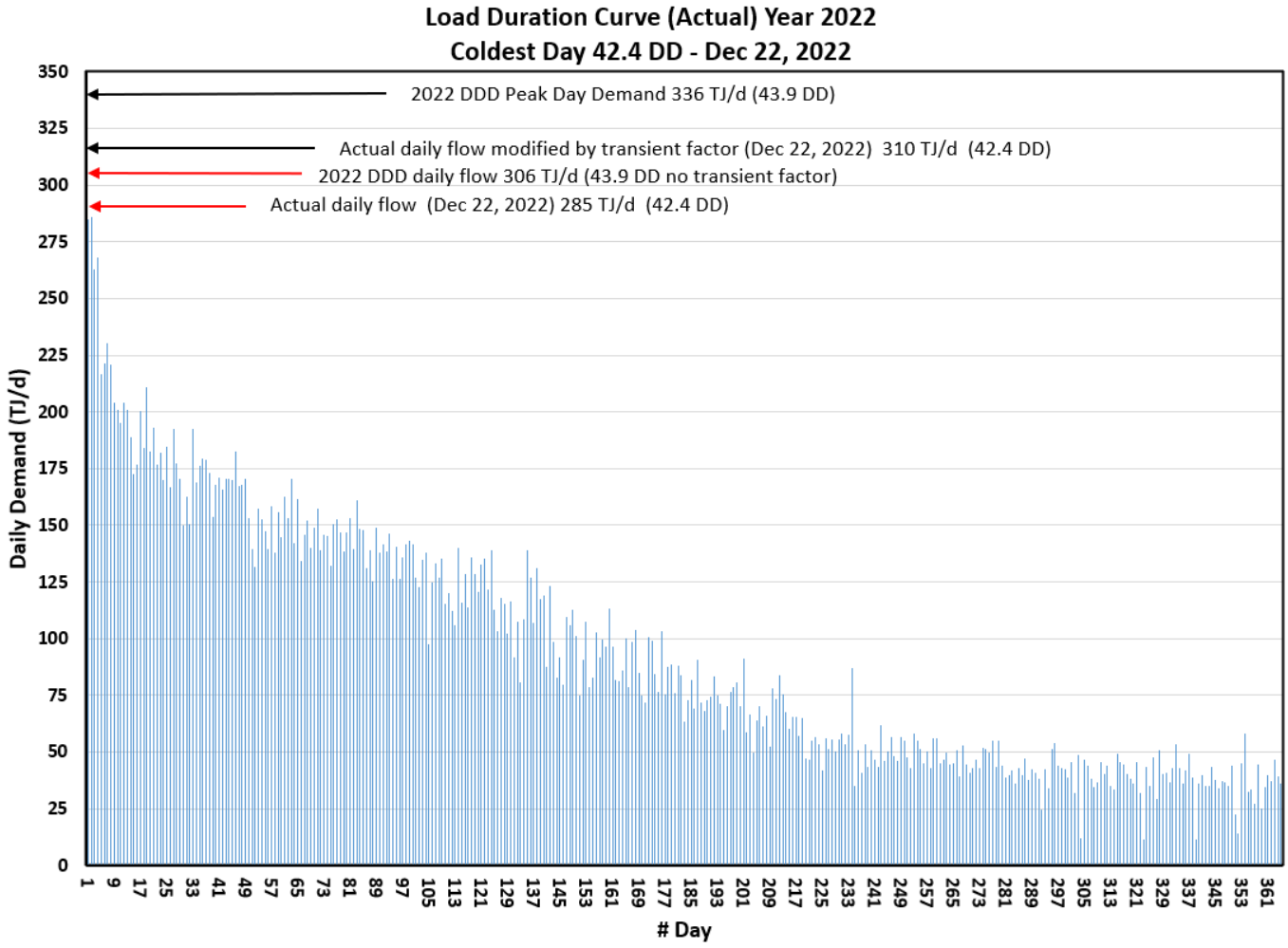
Please see the figure below which has been updated with data from the Supplementary Filing Forecast.



7.2 If there has been a colder day than Jan 14, 2020 recorded in the past three years, please update the graph provided in response to BCUC IR 3.3.1.

1 **Response:**

2 FEI has provided data for 2022 as a 42.4 DD was observed on December 22, 2022 in the ITS.



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8.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-2, BCUC IRs 4.1, 4.1.2; FEI 2022 Long Term Gas Resource Plan proceeding, Exhibit B-1, pp. 4-17, 4-28, 7-28

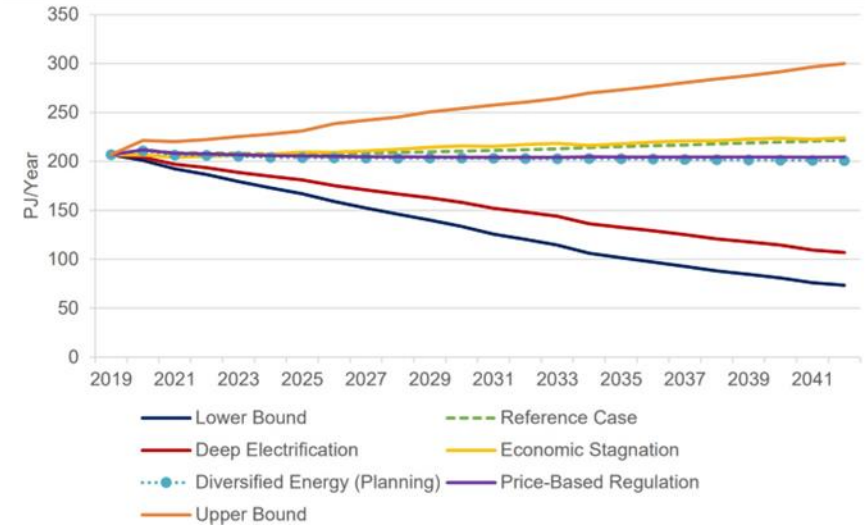
End-Use Peak Demand Forecasting

On page 4-17 of the 2022 Long Term Gas Resource Plan (LTGRP) Application, FEI states:

> The Diversified Energy (Planning) Scenario sets the planning context for FEI's 2022 LTGRP and the actions FEI will take over the next four years to ensure it can meet customers' energy needs over the planning horizon and beyond.

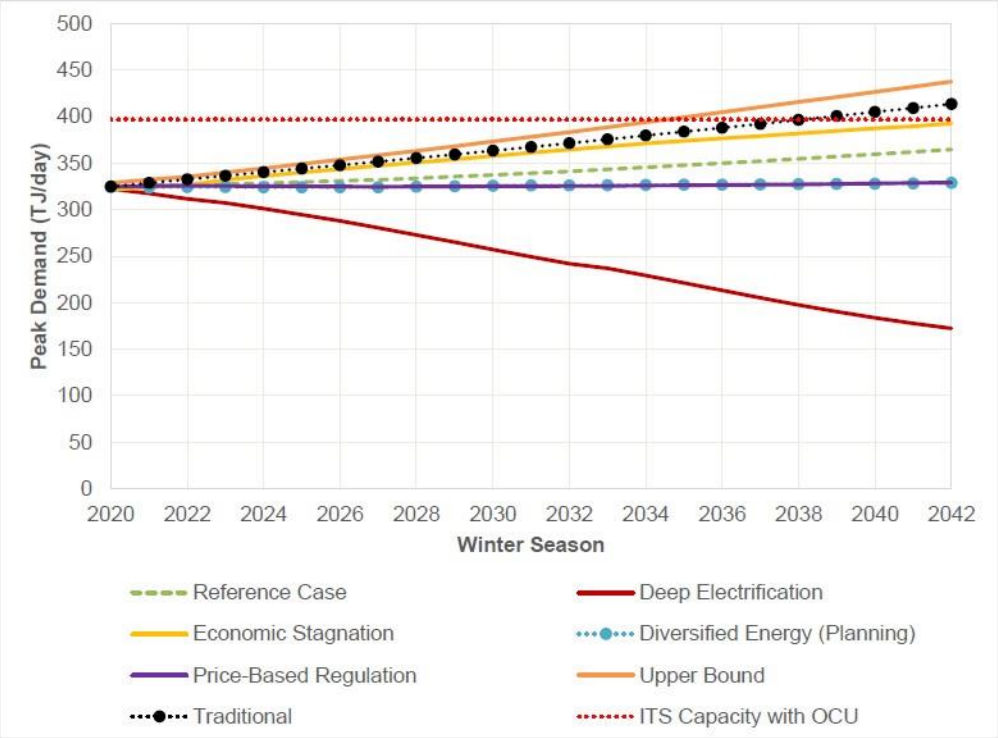
On page 4-28 of the 2022 LTGRP, FEI provides a graph showing annual demand scenarios for residential, commercial and industrial sectors:

Figure 4-9: Annual Demand Scenarios – Residential, Commercial and Industrial Sectors



On page 7-28 of the 2022 LTGRP Application, FEI shows a graph of ITS demand capacity balance using end-use peak demand forecast:

Figure 7-15: ITS Demand-Capacity Balance Using End Use Peak Demand Forecasts



In response to BCUC IR 4.1, FEI stated:

> […] Without direct hourly measurement for residential and commercial customers, FEI has no evidence to support that theoretical modifications to peak demand based on future end-use changes would be reasonable. […]

In response to BCUC IR 4.1.2, FEI stated:

> […] FEI will be submitting a CPCN application for its Advanced Metering Infrastructure Project later this year which, if approved, could provide individual customer metering data that would support a better understanding and application of end-use peak demand forecasting.

By Order C-2-23 dated May 15, 2023, the BCUC approved FEI's Application for a Certificate of Public Convenience (CPCN) and for the Advanced Metering Infrastructure Project (AMI).[8]

8.1 Please provide a discussion of the need for the OCU project under the end-use peak demand forecasts outlined in the 2022 LTGRP, for each scenario shown in Figure 7-15 in the preamble.

[8] https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/521652/index.do.

Response:

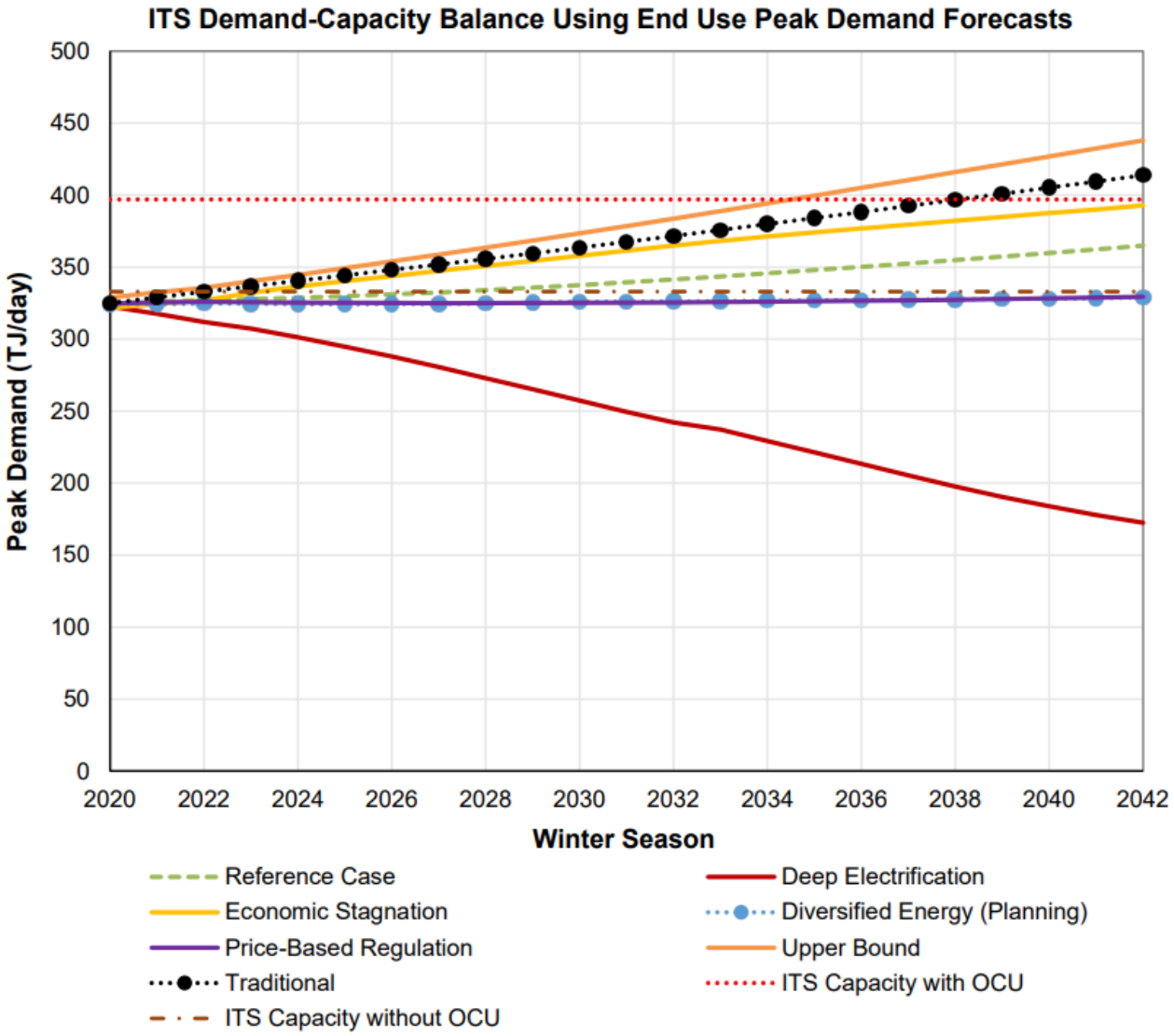
As described in Section 7.2.3 of the 2022 LTGRP, the end-use peak demand forecast is a process that remains theoretical in nature and unsupported by direct measurement. Until data from advanced metering becomes available, FEI's infrastructure planning relies on the Traditional Peak Method, which is predominantly based on the current monthly consumption of FEI's customers.

The Traditional Peak Demand Method is not a scenario method like the end-use forecasts shown in Figure 7-15. Further, it cannot be directly related to the scenarios used for the exploratory end-use peak demand forecast.

As shown in the figure below, if FEI were relying on the exploratory end-use method for peak demand, the version of Figure 7-15 showing Existing Capacity without OCU, as well as Existing Capacity with OCU[9], shows that the Traditional Peak Demand forecast, along with the exploratory Upper Bound, Economic Stagnation and Reference Case scenario peak demand forecasts, will not be met with the capacity available in the ITS without the OCU Project.

With the Diversified Energy (Planning) and Price-Based Regulation scenarios, the following capacity constraint could occur by the end of the planning horizon. In contrast, the Deep Electrification forecast should be met with the capacity available in the ITS without the OCU Project.

[9] FEI 2022 LTGRP proceeding, Exhibit B-10, BCSEA IR1 21 series, page 72. Available online at: DOC_69357_B-10-FEI-response-BCSEA-IR1.pdf (bcuc.com)



8.2 Please explain the key reasons for the differences between the traditional 2022 peak demand forecast and the end-use peak demand forecast for FEI's Diversified Energy Planning scenario.

Response:

The differences between the Traditional Peak Demand forecast results and the exploratory end-use peak demand forecast results under different future scenarios are primarily due to the methods by which they are developed, and the data used as inputs, as described below.

The Traditional Peak Demand forecast uses a time series-based method that examines historic actual demand data. This method works well for short-term forecasting as supported by the practice of updating this forecast annually. The end-use peak demand method uses theoretical annual demand load profiles (versus actual, measured load profiles) for gas equipment over a range of alternative future scenarios that create a series of future energy demand forecasts. This method is less effective in examining shorter term forecasting but is helpful for examining potential outcomes in peak demand over the long-term.

As discussed in Section 7.2.3 of FEI's 2022 LTGRP,[10] FEI's Traditional Peak Method forecast is based on the current peak hour use per customer (UPC_{peak}). When applied to the 20-year account forecast to determine the peak demand forecast, the UPC_{peak} values are assumed to remain unchanged over the planning horizon. As such, this approach has no explicit allowance for evolving customer utilization. However, the estimates of UPC_{peak} and the peak demand forecasts are "point in time" forecasts and are refreshed annually. Therefore, assessments of future capacity constraints and timing of upgrade projects are regularly refreshed with current customer consumption patterns, and end uses that reflect the presently measured impacts of energy economics, housing renewal, and DSM programs.

For the 2022 LTGRP, FEI commissioned Posterity to develop an exploratory process linking peak demand forecasts to the end use scenarios used in the annual demand forecasts. The end use method relies on applying a series of appliance load shape profiles, developed from industry studies on appliance use, to sequentially breakdown annual consumption into peak monthly consumption, monthly to peak daily consumption and finally daily to peak hourly consumption.

Since the end use method is not based on metered FEI customer data, and the effectiveness of DSM programs on peak demand cannot be directly measured until hourly metering is deployed, the Traditional Peak Method forecast, which intrinsically reflects the current effects of DSM programs, remains FEI's base forecast for determining infrastructure requirements and timing for addressing capacity constraints.

[10] Available online at: https://docs.bcuc.com/Documents/Proceedings/2022/DOC_66503_B-1-FEI-2022-LongTermGasResourcePlan.pdf.

8.3 Please discuss the risks associated with relying on the traditional 2022 peak demand forecast to determine the need for the OCU project compared to the end-use peak demand forecasts outlined in the LTGRP.

Response:

The risks associated with the traditional versus the end-use peak forecast methods and the FEI actions that mitigate those risks were discussed in the response to BCUC IR2 104.6 in the LTGRP[11] proceeding and are summarized in Table 1 below.

Table 1: Traditional versus End-Use Peak Forecast Methods - Risks and Actions to Mitigate

Traditional Peak Method Risks	Exploratory End-use Peak Method Risks
Low risk of overestimating peak demand in the short-term.	Risk of underestimating rate and magnitude of peak demand growth, resulting in potential outages during extreme cold weather events, increasing risk to customer health and safety.
Risk of overestimating peak demand in the medium to long term.	Risk of significant impacts to customer health and safety given coincidence of peak demand with extreme cold weather events.
Financial and rate impact risk from over-estimating demand is relatively small since over-estimate may cause project to occur slightly sooner, but would not be avoided.	If large portions of the system experience an outage due to insufficient capacity, relighting efforts could be lengthy, costly and cause ongoing risk to customer health and safety as well as potential economic impacts to affected communities.
Traditional Peak Method Mitigations	**Exploratory End-use Peak Method Mitigations**
Medium to long-term risk is mitigated by continually updating the peak demand forecast annually and where capacity related projects are identified, accounting for changes in actual peak demand up to the point of project application.	Risks mitigated by using the traditional peak method for system design.

FEI's response to BCUC IR2 104.7 in the LTGRP proceeding (Exhibit B-6) also provides important context for considering the risks of relying on one method over the other and is reproduced below.

> In response to BCUC IR 56.3.2.1, FEI provides the following tables outlining the change in DEP annual forecast and traditional peak demand forecast over the 20-year planning horizon:

[11] FEI LTGRP, Exhibit B-23, BCUC IR2 104.6, pp. 136-138.

Region / Transmission System	Customer Class	DEP Annual Forecast	Traditional Peak Demand Forecast
VITS	Residential	14 percent decrease	35 percent increase
	Small Commercial	6.5 percent decrease	48 percent increase
	Large Commercial	30 percent decrease	10 percent increase
	Industrial	16 percent decrease	No change
	Combined	16 percent decrease	27.5 percent increase
CTS	Residential	33 percent decrease	6 percent increase
	Small Commercial	17 percent decrease	17 percent increase
	Large Commercial	40 percent increase	96 percent increase
	Industrial	28.5 percent decrease	No change
	Combined	13 percent decrease	18 percent increase

Region / Transmission System	Customer Class	DEP Annual Forecast	Traditional Peak Demand Forecast
ITS	Residential	30 percent decrease	14 percent increase
	Small Commercial	20 percent decrease	20.5 percent increase
	Large Commercial	82.5 percent increase	250 percent increase
	Industrial	14 percent decrease	No change
	Combined	13.5 percent decrease	32 percent increase

104.7 Given the directional divergence between FEI's planning scenarios for annual demand and peak demand, please discuss how the peak demand forecast can be relied on for the purposes of evaluating the need for future capacity upgrades.

Response:

A key difference in applying the end-use method to the annual forecasting process and applying the same approach to the peak forecasting process is that annual impacts can be measured and verified in sufficient resolution with FEI's existing metering capabilities. Peak-hour and peak-day impacts cannot be sufficiently measured and verified with existing metering capabilities. Therefore, FEI treats end-use peak demand forecasting as a theoretical exercise that can present some possibilities of how peak demand might be influenced through the forecast period but does not consider these forecasts as a reliable planning tool and capable of replacing FEI's traditional method of determining future infrastructure requirements.

FEI uses the Traditional Peak demand forecast to conceive of and determine the preliminary scope of projects to address future capacity needs. Post-conception, FEI continually verifies the project scope and timing based on the most current assessments of peak demand requirements.

8.4 Based on the annual demand forecast for the Diversified Energy Planning scenario in the 2022 LTGRP, please provide a table showing the annual demand forecast for the ITS.

Response:

The Diversified Energy Planning (DEP) Scenario forecast was prepared by segmenting FEI's natural gas system into six regions. The Southern Interior Region is the closest approximation to the ITS available but additionally includes the communities of Ashcroft, Cache Creek, Clinton, Cranbrook, Elkford, Elko, Fernie, Galloway, Jaffray, Kimberley, Logan Lake, Lower Nicola, Merritt, Revelstoke and Sparwood.

The annual demand forecast based on the DEP Scenario using the exploratory end-use peak method is shown in the table below.

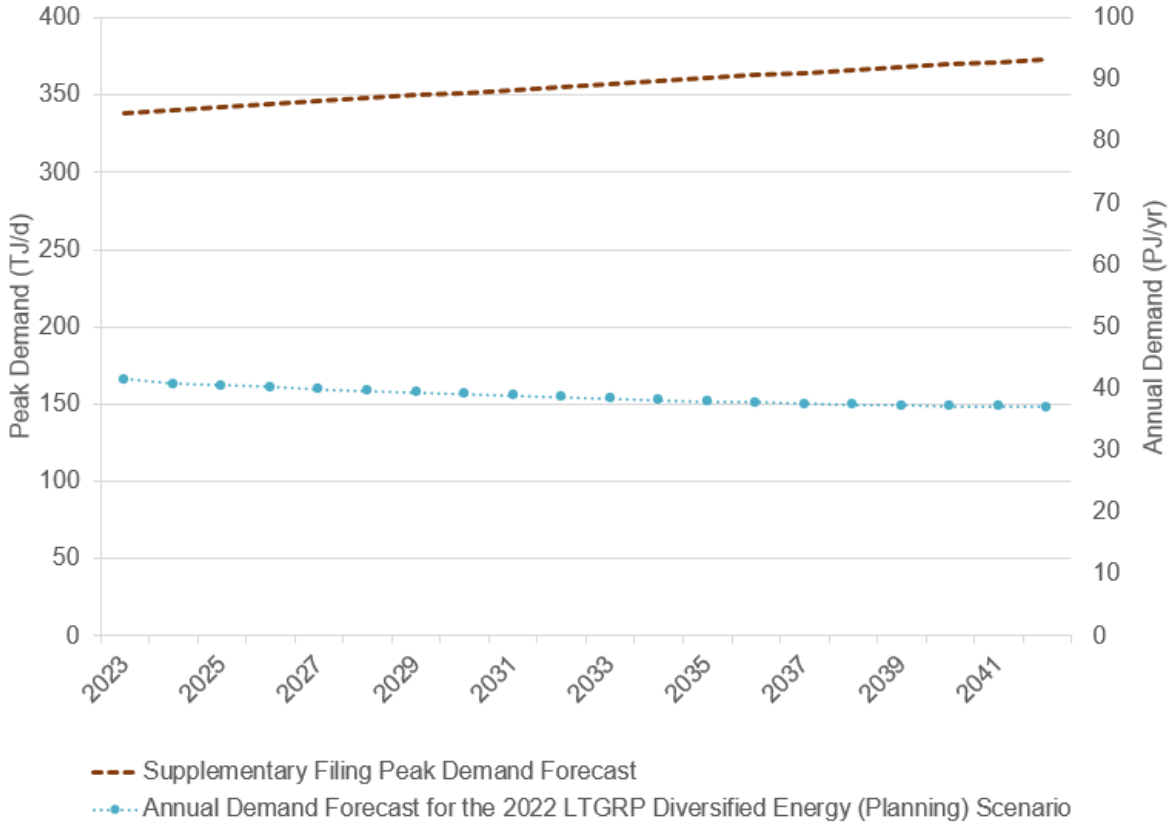
Year	DEP Annual Volume (PJ/Yr)
2019	43.8
2020	42.4
2021	42.4
2022	41.8
2023	41.5
2024	40.7
2025	40.6
2026	40.2
2027	39.9
2028	39.7
2029	39.4
2030	39.2
2031	38.9
2032	38.6
2033	38.4
2034	38.2
2035	38.0
2036	37.8
2037	37.6
2038	37.4
2039	37.3
2040	37.2
2041	37.1
2042	37.1

8.4.1 Please also provide a graph which plots the ITS annual demand forecast for the Diversified Energy Planning scenario, and the ITS 2022 peak demand forecast (using two y axes).

8.4.1.1 To the extent there are directional differences and/or differences in slope between the annual demand forecast and the peak demand forecast, please provide a detailed explanation of any differences. In the case of any directional differences, please also discuss whether there are any non-methodological factors that could cause a directional difference between annual demand and peak demand in the ITS.

Response:

Based on the same Southern Interior Region described in the response to BCUC Supplementary IR1 8.4, the chart below overlays the Supplementary Filing Peak Demand Forecast with the annual demand forecast based on the DEP Scenario.



The figure above shows a decrease in the annual demand forecast for the DEP Scenario while the Supplementary Filing Peak Demand forecast increases over the planning horizon. The two forecasts have some differences that make them difficult to compare directly, and it is expected that the peak demand forecast would not necessarily follow the same trend as the annual demand forecast. For instance, in situations where dual fuel systems are installed in buildings, continued gas deliveries to those buildings will be critical for meeting peak winter energy demand and maintaining a resilient, overall energy system in BC; therefore, even in cases where gas may only be relied on to back up electric systems, FEI anticipates that peak demand will remain the same for such customers.

One difference is that while peak demand forecasts are grouped by transmission systems explicitly, annual demand forecasts are not grouped by the transmission systems but by region. It is reasonable for the regions used in the annual demand DEP Scenario to be grouped to approximately represent (with minor variation) the customers on each system. The Southern Interior region corresponds to the ITS, although some east Kootenay communities outside of the ITS served by transmission laterals are included.

Another difference between the annual and peak demand forecasts is that a proportion of annual demand is attributed to industrial customers in interruptible rate schedules. Interruptible rate schedules are not represented in the peak demand forecast. At the start of the forecast period, customers in interruptible rate schedules account for approximately 28 percent of the annual demand across all FEI systems. For firm industrial rate schedules, there can be a departure in the proportion of demand associated annually and under peak demand for each system.

In the Diversified Energy (Planning) Annual Demand Scenario over the forecast period, some end use patterns and policies in place in the base year are applied to the end-use annual demand forecast but are only captured inherently in the traditional peak demand forecast. For example, the policies that provide reductions to future annual demand are not applied in the traditional peak demand forecast. Therefore, the relationship between the Annual Demand forecast and the Peak Demand forecast is influenced by how these factors are applied to annual demand while not being applied to the Traditional Peak Demand. The Traditional Peak Demand forecast does not apply future demand reductions for various customer classes that are not already captured within the historical actual peak demand. Therefore, peak demand will typically increase by a greater percentage, or will increase when annual demand is declining.

When considering the DEP Scenario forecast, annual demand results from a wider range of end-use influences, including electrification, substantial adoption of renewable gases, high levels of DSM, government policy and programs, etc. are accounted for. The ramping up of various end-use factors in the forecast period for the annual demand analysis drives the change in the relationship between annual demand and peak demand over the forecast period. FEI purposefully does not apply these moderating factors to peak demand forecasts because of the uncertainty in measuring the effect on peak demand and the resulting potential for suppressing the identification

of the need for future infrastructure or forecasting sufficient lead time to implement if the peak reduction potential is over-represented.

8.5 Please describe at a high level how FEI is going to use AMI in the ITS area to prepare peak demand forecasts in future, including whether FEI considers AMI will lead to changes in peak demand forecasting methodology. Please include a discussion of the expected timelines of any future activities related to AMI and peak demand forecasting.

Response:

AMI will provide information and understanding of actual customer demand on a near- to real-time basis. Thus, AMI will provide FEI with more granular information about how demand changes with temperature, which will serve as additional input to refine the peak demand forecast. However, while AMI will provide improved information on customers' total peak load, it will not, on its own, isolate peak demand for specific gas end uses. As a result, FEI may also need to undertake additional studies to better understand the customer usage data as it relates to actual equipment and behaviours that are in place or occur beyond the meter.

Information sufficient to understand, verify, and fully apply meaningful changes to system planning processes, supported by data, and to apply those changes to the system at a larger scale will require data collection and assessment through multiple winter periods in all of FEI's operating regions. FEI expects this to take a few years beyond completion of AMI deployment in all regions. While FEI anticipates that the data gathered as a result of the AMI initiative will help to improve its understanding of peak demand and shifting peak demand trends, it is difficult to predict how FEI's peak demand forecasting practices might change until FEI has sufficient data available for examination and testing.

B. SHORT TERM MITIGATION MEASURES

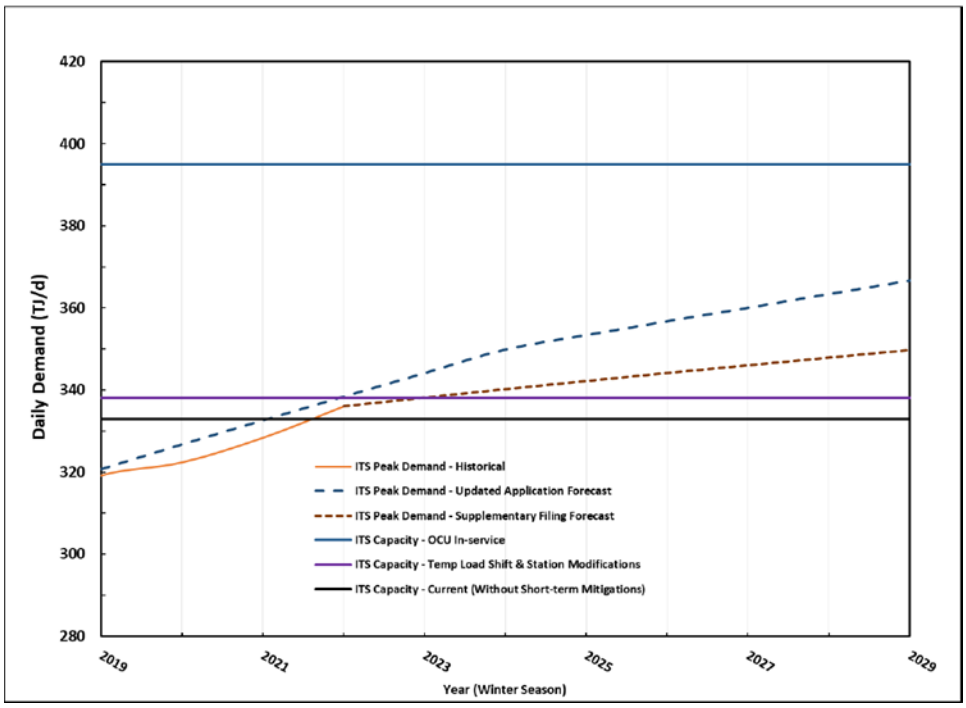
9.0 Reference: SHORT TERM MITIGATION MEASURES

Exhibit B-35, Section 2.1, p. 5; Exhibit B-2, BCUC IR 10.1, 10.2, pp. 49-51; Exhibit B-1-2,

Section 4.2, p. 32; Exhibit B-4, CEC IR 9.1, pp. 17-18 Implementation of Short-Term Mitigation Measures

On page 5 of the Supplementary Filing, FEI provides Figure 2-2, which shows the updated ITS Peak Demand – historical between 2019-2029. Figure 2-2 is reproduced below:

Figure 2-2: Extract from Supplementary Filing Peak Demand Forecast



Further on page 5 of the Supplementary Filing, FEI states:

> Figures 2-1 and 2-2 above also show that demand is forecast to exceed the ITS capacity with short-term mitigation measures in place, resulting in an expected capacity shortfall. With the temporary load shifting and station modification measures in place, a capacity shortfall is expected this winter (i.e., Winter 2023-24), as shown by the intersection of the Supplementary Filing Forecast line and the line titled "ITS Capacity – Temp Load Shift & Station Modifications".

9.1 Please confirm that FEI has started to implement the short-term mitigation measures described in the Supplementary Filing and Section 4.2 of the Updated

Application to increase the capacity of the ITS and provide the required daily demand (TJ/d) to date.

9.1.1 If confirmed, please clarify and discuss the following:

i. The date on which FEI started to implement each mitigation measure

ii. The effectiveness of each mitigation measure to increase the ITS capacity

iii. The challenges or issues, if any, that FEI has experienced during the implementation and execution of each mitigation measure and any actions that have been taken to remediate these challenges or issues

9.1.2 If not confirmed, please explain in detail how FEI has managed and is currently managing meeting daily peak demand on the ITS since the capacity of the ITS system was exceeded in 2022.

9.1.2.1 Please explain when FEI plans to begin implementing the short-term mitigation measures originally proposed in the Updated Application to maximize the current capacity of the ITS until the OCU Project is in service.

Response:

Confirmed. FEI has started to implement the short-term mitigation measures described in the Supplementary Filing and Section 4.2 of the Updated Application.

In general, FEI's approach to utilizing the short-term mitigation measures has been to:

1. Only use the measures if they are necessary to ensure capacity will meet demand; and
2. Prioritize the use of measures that are the least disruptive to FEI's normal operation of its gas system, and that have the lowest cost impact.

Based on this approach, to date, FEI has implemented some, but not all, of the identified short-term mitigation measures. While some measures have not yet been implemented, FEI has taken steps to ensure their readiness to provide mitigation when the need arises (e.g., completing station modifications). FEI describes each short-term mitigation measure below.

Minimum Pressure Increase:

On April 1, 2020, FEI established a verbal understanding with Westcoast Energy Inc. (WEI) that WEI will attempt to maintain a minimum of 650 psig at the Savona custody transfer point. FEI estimates that the minimum pressure increase measure provides a 6 TJ/day increase in capacity to the ITS when combined with the station modifications and load shifting measures.

Please refer to the response to BCUC Supplementary IR1 10.1 for further explanation of the challenges and issues with this measure.

Temporary Load Shifting:

As noted in the Updated Application, FEI's temporary load shifting mitigation measures consist of the following:

1. Undersetting the DP outlet pressure at Polson Gate Station. By undersetting the DP outlet pressure relative to the surrounding gate stations, DP load will be shifted from Polson Gate Station to the surrounding gate stations. This will have the effect of decreasing the flow to Polson Gate Station via the transmission lateral, resulting in a higher TP inlet pressure at the gate station.

    - Date started to implement: FEI implemented this measure in Winter 2022/23. In December 2022, FEI reduced the DP outlet pressure from the normal value of 420 kPag to the underset value of 350 kPag. FEI intends to implement this measure again for Winter 2023/24, as well as each subsequent winter until the OCU Project is in service.
    - Challenges/Issues: No challenges/issues were encountered when implementing this measure.

2. Undersetting the DP outlet pressure at Kelowna #1 Gate Station. By undersetting the DP outlet pressure relative to the surrounding gate stations, DP load will be shifted from Kelowna #1 Gate Station to the surrounding gate stations. This will have the effect of decreasing the flow to Kelowna #1 Gate Station via the transmission lateral, resulting in a higher TP inlet pressure at the gate station.

    - Date started to implement: Measure has not yet been implemented. Per the Supplementary Filing Forecast, this measure is required for the upcoming winter (Winter 2023/24). As such, FEI intends to implement this measure for Winter 2023/24, as well as each subsequent winter until the OCU Project is in service.
    - Challenges/Issues: As FEI has not yet implemented this measure, no challenges or issues have been encountered. Please refer to the response to BCUC Supplementary IR1 10.1 for FEI's concerns with this measure.

3. Change the supply to Coldham Road Gate Station. Coldham Road Gate Station is currently supplied by Kelowna #1 Gate Station via the West Kelowna IP system. Coldham Road station has the ability to instead be supplied by the transmission system via the Westbank lateral. This will have the effect of reducing the flow through the West Kelowna IP system and thus the Kelowna #1 Gate Station, resulting in a higher TP inlet pressure at the gate station.

- Date started to implement: Measure has not yet been implemented. Per the Supplementary Filing Forecast, this measure is required for the upcoming winter. As such, FEI intends to implement this measure for Winter 2023/24, as well as each subsequent winter until the OCU Project is in service.
- Challenges/Issues: As FEI has not yet implemented this measure, no challenges or issues have been encountered.

In terms of effectiveness, collectively, the load shifting measures increase ITS capacity by an estimated 1 TJ/day.

Station Modifications:

As noted in the Updated Application, FEI's station modification mitigation measures consist of the following:

1. Kelowna #1 Gate Station TPIP Bypass.

   - Date started to implement: This measure has not yet been implemented. Construction of the TPIP bypass is underway and is expected to be complete in October 2023, thus the measure will be available for FEI to use if needed in Winter 2023/24. Per the Supplementary Filing Forecast, this measure is required at peak conditions for the upcoming winter (Winter 2023/24). As such, FEI will monitor for peak winter conditions, and if required implement this measure.
   - Challenges/Issues: As FEI has not yet implemented this measure, no challenges or issues have been encountered. Please refer to the response to BCUC Supplementary IR1 10.1 for FEI's concerns with this measure.

2. Polson Gate Station TPIP Bypass.

   - Date started to implement: This measure has not yet been implemented. Construction of the TPIP bypass was completed in September 2022, thus the measure is available for FEI to use. Per the Supplementary Filing Forecast, this measure is required at peak conditions for the upcoming winter (Winter 2023/24). As such, FEI will monitor for peak winter conditions, and if required implement this measure.
   - Challenges/Issues: As FEI has not yet implemented this measure, no challenges or issues have been encountered. Please refer to the response to BCUC Supplementary IR1 10.1 for FEI's concerns with this measure.

In terms of effectiveness, collectively, the station modification measures increase ITS capacity by an estimated 3 TJ/day.

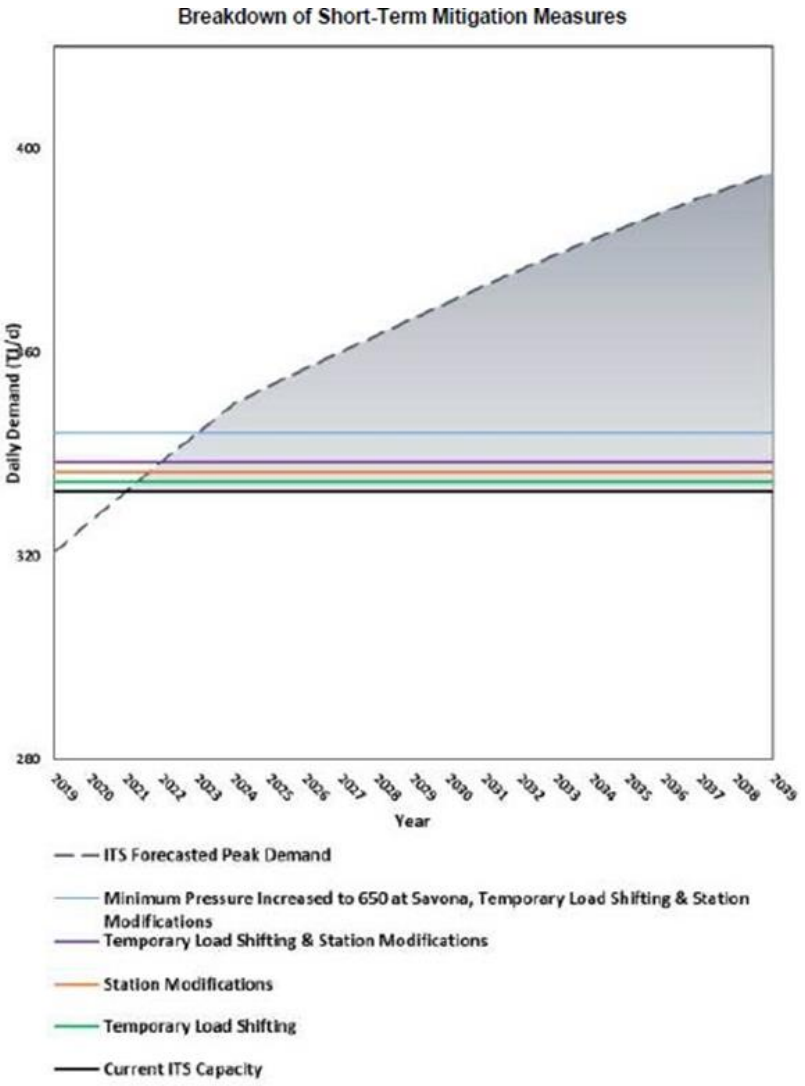
9.2 Please explain whether FEI has identified any additional short-term mitigation measures (i.e. other than the measures described in the Updated Application) that could potentially be implemented now or in the future winters to increase the capacity of the ITS.

9.2.1 If applicable, please describe the identified short-term mitigation measures and explain whether there are any concerns with respect to reliability and implementation. Please provide the contribution to the ITS capacity from each of the identified short-term mitigation measures, and the estimated costs to implement.

Response:

FEI has not identified any additional short-term mitigation measures beyond those described in the Updated Application.

In response to BCUC IR 10.2 (Exhibit B-2), FEI provides a graphical representation of the breakdown of the estimated contribution of each of the mitigation measures, which also includes the capacity of the ITS with mitigation measures modelled with a minimum delivery pressure of 650 psig at Savona. The breakdown of short-term mitigation measures figure is reproduced below:



9.3 Please reproduce Figure 2-2 (referenced in the preamble), showing the following:

i. The 2022 peak demand forecast outlined in the Supplementary Filing

ii. The breakdown of the short-term mitigation measures with their respective contribution (TJ/d) to the ITS capacity

iii. The combined short-term mitigation measures assuming a minimum delivery pressure of 650 psig at the custody transfer point at Savona.

9.3.1 In addition, please provide the data in tabulated form.

Response:

Figure 1 below provides Figure 2-2 referenced in the preamble updated showing the above-mentioned datapoints. The data is provided in Table 1 below in tabular form as well.

Figure 1: Updated Figure 2-2

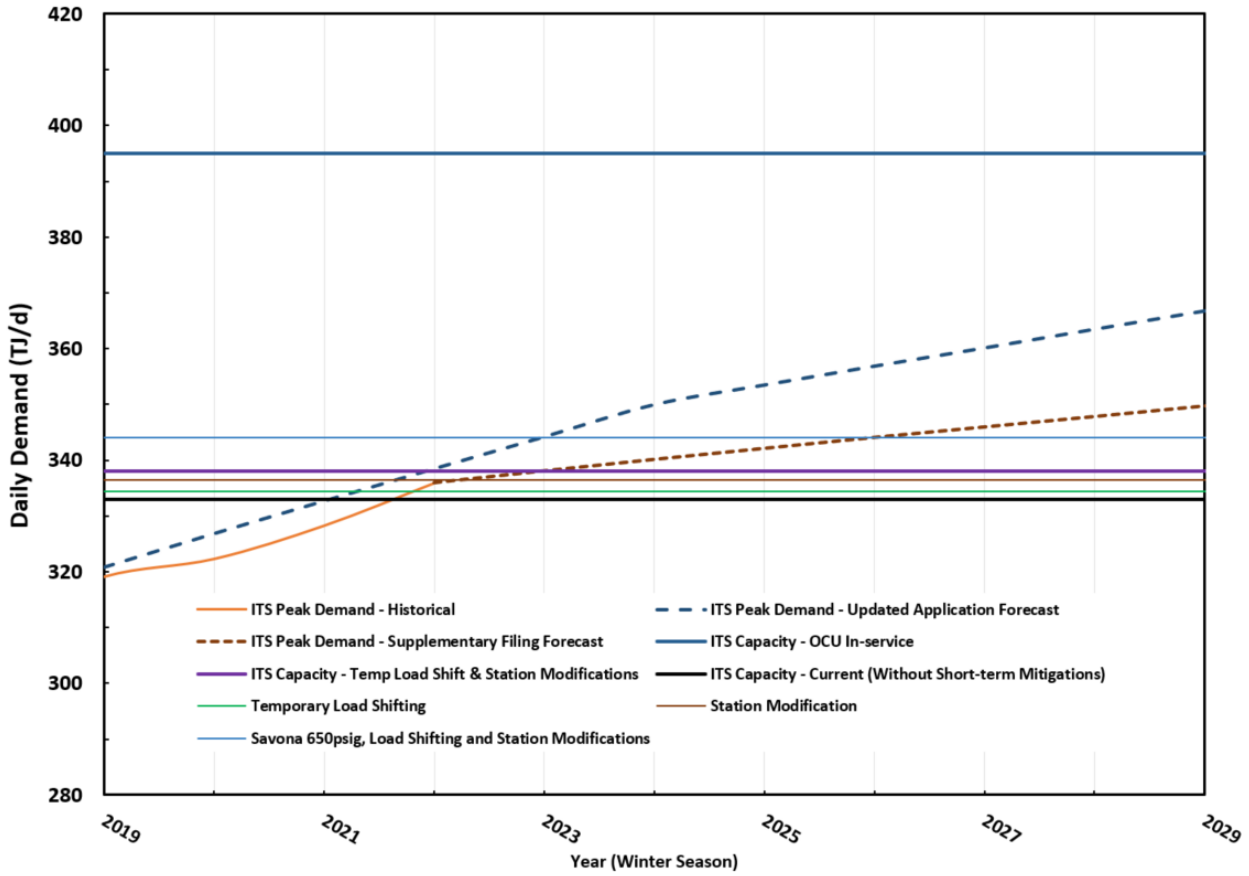


Table 1: Data for Figure 1

Year	Supplementary Filing Peak Demand	Temporary Load Shifting	Station Modifications	Load Shifting and Station Modifications	Savona 650psig, Load Shifting and Station Modifications
2022	336	334	336	338	344
2023	338	334	336	338	344
2024	340	334	336	338	344
2025	342	334	336	338	344
2026	344	334	336	338	344
2027	346	334	336	338	344
2028	348	334	336	338	344

Year	Supplementary Filing Peak Demand	Temporary Load Shifting	Station Modifications	Load Shifting and Station Modifications	Savona 650psig, Load Shifting and Station Modifications
2029	350	334	336	338	344
2030	352	334	336	338	344
2031	353	334	336	338	344
2032	355	334	336	338	344
2033	357	334	336	338	344
2034	359	334	336	338	344
2035	361	334	336	338	344
2036	363	334	336	338	344
2037	364	334	336	338	344
2038	366	334	336	338	344
2039	368	334	336	338	344
2040	370	334	336	338	344
2041	371	334	336	338	344
2042	373	334	336	338	344
2043	375	334	336	338	344

In response to BCUC IR 10.1, FEI stated the following regarding the temporary load shifting mitigation measure:

> […] The acceptance of very low inlet pressures through Polson and Kelowna #1 Gate Stations means a decreased capacity in the downstream DP and IP systems. FEI's modeling indicates that with planned station upgrades in these systems, acceptable capacity can be maintained only through the winter of 2021/2022. As demand on these systems continues to increase, full flow through these stations is likely to be required. Thus this measure can only be maintained temporarily.

9.4 Please provide a graphical representation of the historical (2019-2022) and forecast (2023-2029) inlet pressures at the Kelowna #1 and Polson Gate Stations at peak demand conditions prior to and following the implementation of short-term mitigation measures. To the extent it is feasible, please also include in the graph the differential pressure across the gate stations. Please provide the data points in a table.

Response:

Please refer to Figure 1 and Table 1 below. Data for the "without mitigation measures" is not shown beyond 2023 as the simulation is unable to produce a feasible result. Similarly, data for the "with mitigation measures" cases is not available beyond 2026. It is infeasible to produce the gate station differential pressure information at this time.

Figure 1: Minimum Pressure Readings on Winter Season Peak Days

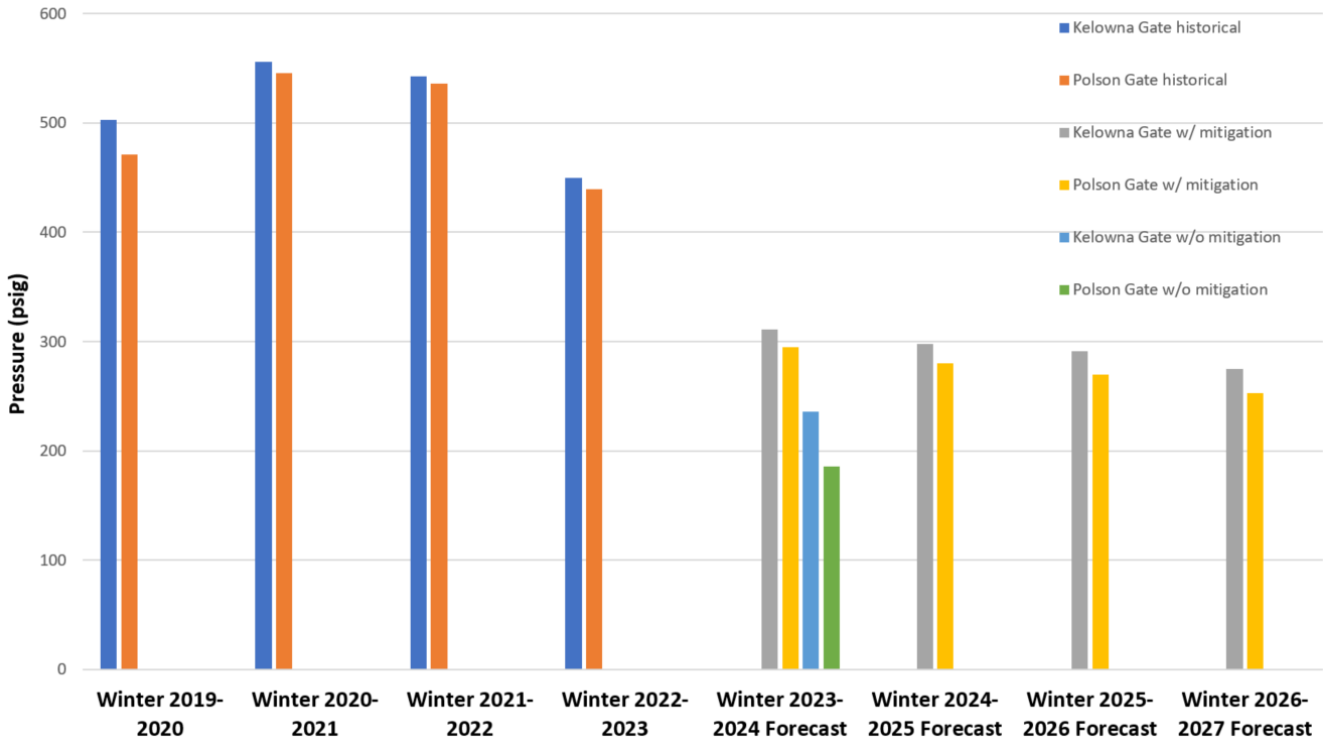


Table 1: Data for Figure 1

Season	Station Inlet Pressure (psig)		Station Inlet Pressure (psig) with Mitigation		Station Inlet Pressure (psig) without Mitigation	
	Kelowna Gate historical	Polson Gate historical	Kelowna Gate w/ mitigation	Polson Gate w/ mitigation	Kelowna Gate w/o mitigation	Polson Gate w/o mitigation
Winter 2019-2020	503	471				
Winter 2020-2021	556	546				
Winter 2021-2022	543	536				
Winter 2022-2023	450	440				
Winter 2023-2024 Forecast			311	295	236	185
Winter 2024-2025 Forecast			298	280		

Season	Station Inlet Pressure (psig)		Station Inlet Pressure (psig) with Mitigation		Station Inlet Pressure (psig) without Mitigation	
	Kelowna Gate historical	Polson Gate historical	Kelowna Gate w/ mitigation	Polson Gate w/ mitigation	Kelowna Gate w/o mitigation	Polson Gate w/o mitigation
Winter 2025-2026 Forecast			291	270		
Winter 2026-2027 Forecast			275	253		

9.5 Please explain whether FEI has observed any impact on the downstream IP/DP systems due to the implementation of the short-term mitigation measures described in the Supplementary Filing, i.e. load shifting and station modifications.

9.5.1 If any impact on supply demand in the downstream IP/DP systems has been observed, please explain how FEI has managed to supply the required peak demand to customers in these areas.

9.5.2 With mitigation measures in place, please clarify whether FEI is expecting the inlet pressures of the downstream IP/DP systems (e.g. Vernon/Polson, West Kelowna) to be operationally inadequate to provide a safe and reliable service to customers in these areas by the winter of 2023/2024.

Response:

To date, a shift of flow in the Fall of 2022 towards Vernon Gate Station was experienced due to changes to the Polson station setpoint. The distribution system was able to accommodate the shift in distribution without impacting deliveries as it has some capacity. No other impacts have been specifically observed.

With the short-term mitigation measures in place, FEI anticipates having adequate capacity to provide reliable service to the stations referenced in the preamble through Winter 2023/2024.

9.6 If applicable, please describe the station upgrades to the downstream DP and IP systems that FEI has undertaken to date or is forecasting to undertake.

Response:

In addition to the bypass modifications at the Kelowna #1 Gate Station and Polson Gate Station, FEI has completed, or is in the process of completing, the following station modifications to maintain acceptable IP and DP system capacity in the short-term:

- Peachland Gate Station – Regulator upgrade to maintain station capacity at lower inlet pressure (completed);
- Westbank District Station – Regulator upgrade to maintain station capacity at lower inlet pressure (completed); and
- Lavington District Station – Regulator upgrade to maintain station capacity at lower inlet pressure (in progress – planned completion is 2023).

On page 32 of the Updated Application, FEI states:

> As explained in the following section, FEI has determined that short-term mitigation measures may be required to maintain sufficient capacity for the winters of 2021/2022 and 2022/2023. However, these interim measures are not viable to support projected demand in 2023/2024, and a longer-term solution must be implemented prior to this point.

In response to BCUC IR 10.1, FEI stated the following regarding the reliability of the station modification measures:

> […] Manual operation of bypass valves which directly interconnect the transmission and intermediate pressure systems will be performed by qualified and trained FEI operations personnel; however, this will involve logistical challenges and risk. While FEI is confident the measure can be successfully executed for short periods, significant local operational effort and oversight will be required to ensure safe operation of the system.

9.7 Please elaborate on the significant local operational effort and oversight that are required to ensure safe operation of the system while manually bypassing the major gate stations of the distribution system. In the response, please include consideration of FEI's current plans to continue relying on the station modification measures for the winters of 2023/2024, 2024/2025, and 2025/2026 and until the OCU project is in service.

Response:

The significant local operational effort and oversight consists of the following:

1. **Impact to Operations personnel:** The need for FEI to operate the bypass will coincide with extremely cold weather. Personnel dispatched to set up and operate the bypass will be exposed to this extreme cold weather while driving and operating the bypass. Additional oversight and support are required to ensure the personnel are able to undertake the work in these conditions safely.

   FEI intends to use the station modification measures as required for the winters of 2023/24, 2024/25, and 2025/26 (i.e., until the OCU Project is in-service in Winter 2026/27). FEI will resource this work by monitoring forecasts of extreme cold weather and prioritizing operation and support of these bypasses over other work that will be delayed. Should the OCU Project not be installed by Winter 2026/27, FEI will continue to use the station modification measures until the OCU Project is in place. However, FEI notes that, as indicated by the Supplementary Filing Forecast, the measures would not provide sufficient capacity to meet the forecast demand, and thus a capacity shortfall would be expected in Winter 2026/27.

2. **Additional strain on operational resources during extreme cold weather:** If FEI is required to implement the full station bypasses, then personnel from Operations will be needed to switch the station over from normal operation to bypass operation, and to operate the site while on bypass. This will result in fewer resources being available for other operational needs, which FEI will manage by deferring other operational needs until the extreme cold weather has passed.

In response to CEC IR 9.1, FEI stated:

> […] Until the Project is complete, FEI will be required to make some temporary allowances to mitigate the impact of increasingly low station inlet pressure and maintain gas supply and reliable service to all customers. The temporary allowances or short- term mitigation measures do not address the overall decline in system pressure. This decline in pressure is driven by customer growth and the associated increase in peak demand each year. Therefore, the allowances are only short term.

Further on page 18 of Exhibit B-4, FEI provides a description of the measures that were planned to be undertaken in the winters of 2021/2022, and 2022/2023.

9.8 Considering FEI's initial plans to rely on the mitigation measures for the short term, please explain whether FEI foresees any issues with respect to reliable operation of the systems and service to all customers that could arise due to the prolonged use of the mitigation measures during the winters of 2023/2024, 2024/2025, and 2025/2026 and until the OCU project is completed.

Response:

FEI notes that of all the short-term mitigation measures, the full station bypass (temporary station modification) has the greatest potential to impact system reliability.

FEI acknowledges that implementing the full station bypass is less reliable than normal operation of the gate station, and as such creates a system reliability risk. FEI also acknowledges that due to the prolonged use of the mitigation measure, FEI is exposed to this risk for a longer duration than was expected when preparing the Updated Application. FEI does not consider the increase in system reliability risk due to extending the exposure from one year to three years to be unacceptable due to the low likelihood of the risk event happening. For the event to occur, FEI would need to experience peak demand conditions, as well as a failure of the bypass (e.g., equipment failure, operator error, etc.). Additionally, FEI will deploy the necessary operational resources to ensure the safe operation of the system and thus mitigate the reliability risk. As such, FEI does not foresee issues with respect to the reliable operation of the system due to the aforementioned prolonged use of the mitigation measures.

FEI does not have any reliability concerns with regard to the station load shifting measure. Please also refer to the response to BCUC Supplementary IR1 10.2.

10.0 Reference: SHORT TERM MITIGATION MEASURES

Exhibit B-35, Section 2.1, p. 5; Exhibit B-2, BCUC IR 10.1, p.49
Minimum Pressure Increase at Savona Compressor Station

On page 5 of the Supplementary Filing, FEI states:

> With the temporary load shifting and station modification measures in place, a capacity shortfall is expected this winter (i.e., Winter 2023-24), as shown by the intersection of the supplementary Filing Forecast line and the line titled "ITS Capacity – Temp Load Shift & Station Modifications".
>
> FEI has also worked with Westcoast Energy Inc. (WEI) on an additional short-term capacity mitigation wherein WEI will attempt to provide FEI with a minimum Savona tap pressure of 650 psig. Incorporating this additional measure (i.e., with the Temporary Load Shifting, Station Modifications, and Savona Tap Pressure Increase all being in place), results in the Supplementary Filing Forecast deferring the predicted capacity shortfall to no later than Winter 2026-27. FEI notes that no firm contractual obligation exists to provide this tap pressure between FEI and WEI, and as such, there is no guarantee of the availability of this temporary measure.

In response to BCUC IR 10.1, FEI discussed the reliability, expansion, and longevity concerns of the implementation of a minimum pressure increase at Savona to further increase the current capacity of the ITS:

> An ongoing minimum pressure increase was not represented in the short-term mitigation measures which formed the basis for Figure 4-1 as FEI cannot depend on the additional 50 psig of pressure at Savona. FEI has a verbal understanding that Enbridge will attempt to maintain a minimum 650 psig pressure at the custody transfer point at Savona; however, no firm contractual obligation exists. For this reason, FEI cannot consider this measure reliable. However, when available, this increased pressure will improve the effectiveness of the other short term mitigation measures.

10.1 In the absence of firm contractual obligations between FEI and WEI and the lack of guarantee of the availability of this temporary measure, please explain, with rationale, how FEI plans to manage the delivery of peak demand once the capacity of the ITS, with implemented mitigation measures, is exceeded and until the OCU project is completed, i.e., the winter periods of 2023/2024, 2024/2025, and 2025/2026.

10.1.1 What actions would FEI need to take if the minimum delivery pressure at Savona could not be increased to 650 psig when needed?

Response:

FEI is confident that, given the current operating parameters of WEI's system at the connecting location and the verbal discussions between FEI and WEI, the higher inlet pressure will be available to FEI when required during the winter periods of 2023 through 2026. Higher demand winter operating conditions on WEI require each compression station on T-South to meet a discharge pressure of greater than 650 psig. The Savona delivery point from WEI has a tie-in immediately downstream of Compressor Station 7.

However, in the unlikely event that WEI is unable to provide the increased minimum delivery pressure during cold temperatures prior to the OCU Project being installed (i.e., before Winter 2027/28), FEI would be forced to implement strategic curtailment of larger firm customers to reduce demand during peak conditions.

10.2 Please discuss any risks associated with the absence of a guarantee to maintain a continuous minimum delivery pressure at Savona of 650 psig and how FEI plans to mitigate them.

Response:

FEI clarifies that it does not require a continuous minimum delivery pressure at Savona of 650 psig to serve its customers during the capacity shortfall forecast to Winter 2026/27. FEI only requires the increased minimum delivery pressure during cold weather conditions that approach FEI's Design Degree Day for the region.

The main risk associated with the absence of a guarantee is that, during those cold weather conditions when FEI requests the higher delivery pressure, WEI is unable to provide the higher pressure. Given the nature of the interconnect, FEI only expects this to be the case if WEI has an equipment failure on their Compressor Station 7.

FEI continually monitors the 7-day temperature forecast when cold weather is expected. Should FEI identify temperatures that require the higher delivery pressure from WEI, FEI will contact WEI in the days leading up to the requirement. FEI will therefore know whether the pressure will be available. In the unlikely event that WEI is unable to provide the pressure, FEI would initiate strategic curtailment of larger firm customers to reduce demand on the system.

10.3 Please explain whether FEI would reconsider the use of other mitigation measures, such as supplemental CNG injection or LNG supplementation, in the event of a capacity shortfall due to WEI being unable to deliver a minimum pressure of 650 psig after the winter of 2023/2024.

Response:

Please refer to the response to BCUC IR2 48.1 for more information on why FEI has not reconsidered the use of supplemental CNG or LNG supplementation. The challenges listed in the response to BCUC IR2 48.1 continue to hold true, while the cost associated with the implementation has likely increased due to inflationary factors.

C. DESCRIPTION AND EVALUATION OF ALTERNATIVES

11.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-35, Section 2.1, pp. 1 and 5 Updates to Evaluation of Alternatives

On page 1 of the Supplementary Filing, FEI states:

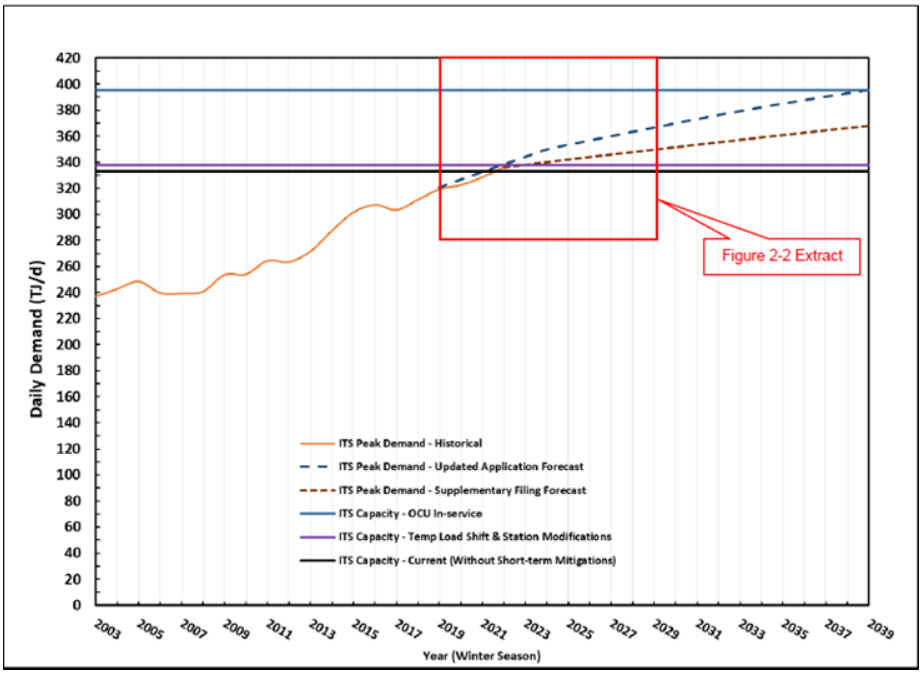
- **Section 4: Description and Evaluation of Alternatives** – FEI notes that there are no updates to the evaluation of alternatives considered and selection of the preferred solution discussed in Section 4 of the Updated Application.

On page 3 of the Supplementary Filing, FEI states:

> FEI updated the peak demand forecast for the ITS in 2023 (referred to as the "Supplementary Filing Forecast" in this document). Though the Supplementary Filing Forecast shows comparatively lower peak demand relative to the Updated Application Forecast.[…]

Further on page 4 of the Supplementary Filing, FEI provides Figure 2-1, which shows the Supplementary Filing Peak Demand Forecast. Figure 2-1 is reproduced below:

Figure 2-1: Supplementary Filing Peak Demand Forecast



11.1 Please explain why no update to the evaluation of alternatives considered and selection of the preferred solution for the project were provided in the

Supplementary Filing, considering the 2022 peak demand forecast shows lower peak demand compared to the Updated Application forecast.

11.1.1 Please describe how the scoring of each alternative considered in the Updated Application would be affected by the updated peak demand forecast in the Supplementary Filing.

Response:

FEI interprets this IR as referring to the lower peak demand between the "Updated Application Forecast" and the "Supplementary Filing Forecast". Please refer to the response to BCUC Supplementary IR1 1.1 for clarification regarding the terminology and basis of the Supplementary Filing Forecast, 2022 Peak Demand Forecast, and Updated Application Forecast.

FEI did not update the evaluation of alternatives because the key reasons for the selection of the preferred alternative are not impacted by the reduction in forecasted peak demand between the Updated Application and the Supplementary Filing; therefore, the scoring of each alternative would not change materially. Please see the following table for a summary of the rationale for why each alternative was not selected as the preferred alternative in the Updated Application.

Alternative	Rationale for Not Being Selected as Preferred Alternative
Alternative 1 – ITS Upgrades to VER PEN 323	Significant schedule risk and impact to the public from the re-hydrotesting scope of work.
Alternative 2 – Modified ITS Upgrades to VER PEN 323	Significant schedule risk and impact to the public from the re-hydrotesting scope of work.
Alternative 4 – 508 mm Loop from Savona	Not feasible as project schedule does not align with the required project in-service date.[12]
Alternative 5 – LNG Facility Near Vernon	Not feasible as project schedule does not align with the required project in-service date.[13]

With regard to the two other feasible alternatives (i.e., Alternatives 1 and 2), as summarized in the above table, the primary factor which resulted in these alternatives being eliminated was the significant schedule risk and impact to the public from the re-hydrotesting scope of work. In Table 4-9 of the Updated Application, this factor was addressed under the Project Execution and Lifecycle Operation criterion and, as that table demonstrated, the scoring for Alternatives 1 and 2 was "red" (i.e., both alternatives received a score of 1.45). In comparison, the preferred Alternative 3 received a "yellow" score of 3. The scoring of the three feasible alternatives does not change

[12] Please refer to the response to BCUC Supplementary IR1 11.1.2 for further discussion on why Alternative 4 and Alternative 5 remain unfeasible under the Supplementary Filing Forecast.

[13] Please refer to the response to BCUC Supplementary IR1 11.1.2 for further discussion on why Alternative 4 and Alternative 5 remain unfeasible under the Supplementary Filing Forecast.

as a result of the Supplementary Filing Forecast, as all of the risks and challenges described in the Updated Application regarding Project Execution and Lifecyle Operation remain.

When preparing the Supplementary Filing with the updated forecast information, FEI revisited the scope of Alternative 3 based on the Supplementary Filing Forecast and found that the impact was relatively minor in comparison to the overall Project, allowing FEI to potentially reduce the length of the pipeline scope from roughly 30 km to roughly 26 km.[14] This is discussed in detail in the responses to BCUC Supplementary IR1 13.2 and 13.2.2.

After considering the updated forecast information (i.e., the Supplementary Filing Forecast) and the scope refinement to Alternative 3, FEI determined that the relative scoring of the OCU Project alternatives did not change materially (in fact, as further explained in the responses to BCUC Supplementary IR1 13.2 and 13.2.2, the scope refinement would result in a reduction to the OCU Project cost and would therefore only increase the scoring of the preferred alternative relative to the other two feasible alternatives). Thus, FEI's preferred Project alternative (i.e., an extension of the existing OLI PEN 406 pipeline) has not changed.

11.1.2 Please explain, with rationale, whether FEI screened out any of the project alternatives due to insufficient capacity (i.e. extent of capacity increase), which could now potentially be feasible.

Response:

No, FEI did not screen out any of the project alternatives due to insufficient capacity. Two potential project alternatives were screened out by FEI: Alternative 4 – 508 mm Loop from Savona and Alternative 5 – LNG Facility Near Vernon. Both screened alternatives met the capacity objective for the OCU Project but were screened out due to the project schedules not meeting the objective of having the project in service by Winter 2023/24:

1. For Alternative 4, the project schedule issue was due to permitting challenges associated with the Environmental Assessment (EA) that would be required (please see the response to BCUC Supplementary IR1 12.1 confirming that an EA would still be required for Alternative 4).
2. For Alternative 5, the project schedule issue was due to the complexity of designing and constructing an LNG facility.

[14] Please refer to the responses to BCUC Supplementary IR1 13.2 and 13.2.2 for further explanation of the cost implications of this scope reduction.

FEI notes that the required OCU Project in-service date of Winter 2023/24 has been pushed to Winter 2026/27 due to the Supplementary Filing Forecast. However, even with the revised required in-service date, the scheduling challenges noted above would result in Alternatives 4 and 5 not being installed in time to prevent the expected capacity shortfall in Winter 2026/27.

The factors that resulted in Alternatives 4 and 5 being screened out still remain under the Supplementary Filing Forecast, as such these alternatives remain unfeasible.

12.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-2, Section 4.3.4, p. 42, Section 4.4.2, p.45; Exhibit B-35, Section 2.1, p. 4; Exhibit B-14, BCUC IR 51.2, p. 61; Exhibit B-2, BCUC IR 19.1.2, p.81

Environmental Assessment Requirements for Alternative 4

On page 42 of the Updated Application, FEI states:

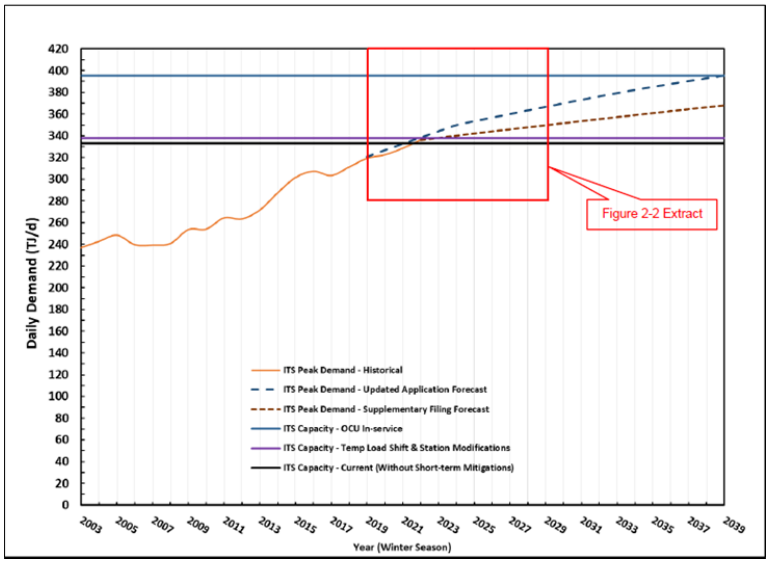
> The fourth alternative to address the capacity constraint involves the installation of a 508 mm loop starting at the Savona Compressor Station and running eastward for approximately 68.4 km before terminating east of Kamloops.

On page 45 of the Updated Application, FEI states:

> Alternative 4 would meet one of the objectives for this project: to increase the capacity of ITS. However, the length and diameter of this pipeline would trigger an environmental assessment (EA). The anticipated timeline for completion of an EA is three years. Due to this delay, it is highly unlikely that construction of this pipeline could begin prior to 2024. Pipeline installation is likely to take approximately three years due to the length and complexity of this pipeline route, indicating a completion date of 2027 or later. A capacity shortfall which requires significant, lasting mitigation is expected to occur in the winter of 2023/2024… For this reason, FEI does not consider Alternative 4 to meet the primary project objectives as it does not mitigate the risk of capacity shortfall within an acceptable timeframe.

On page 4 of the Supplementary Filing, FEI provides Figure 2-1, which shows the Supplementary Filing Peak Demand Forecast. Figure 2-1 is reproduced below:

Figure 2-1: Supplementary Filing Peak Demand Forecast



In response to BCUC IR 51.2, FEI states:

> When comparing Alternatives 3 and 4, the longevity and expandability of each solution must be considered. In order to meet FEI's forecast capacity needs to the end of the planning period (2039), Alternative 4 would also require a future significant and costly pipeline extension to provide the required capacity. In contrast, Alternative 3 would be able to meet the capacity needs at the end of the period while only requiring a future compressor upgrade at a single existing site. This compressor upgrade for Alternative 3 would be much less costly than the pipeline expansion required for Alternative 4. On this basis, the total cost of Alternative 4 would be significantly higher than Alternative 3, without providing any additional capacity benefit. [emphasis added]

In response to BCUC IR 19.1.2, FEI states:

> The table below shows the forecast inlet pressure for each major gate station within the ITS for the period 2021 to 2035, if the pipeline proposed in Alternative 4 were to be installed by 2023. As indicated in the response to BCUC IR1 19.1, Alternative 4 would need additional upgrades in 2031 in order continue to maintain the inlet pressures to these gate stations above the 350 psig minimum requirement.

Upstream Pressure at Major Okanagan IP Gate Stations

Year	Kamloops #1 psig	Polson psig	Kelowna #1 psig	Kelowna - Cary Rd psig
2021	640	297	316	377
2022	622	245	268	341
2023	746	445	430	486
2024	744	426	406	468
2025	743	414	391	458
2026	739	399	373	445
2027	734	383	354	431
2028	729	391	396	416
2029	724	380	373	400
2030	720	363	355	384
2031	715	*345*	*336*	367
2032	710	*327*	*317*	350
2033	705	*307*	*295*	*333*
2034	701	*287*	*274*	*315*
2035	697	265	251	296

12.1 Based on the updated peak demand forecast in the Supplementary Filing, please provide the revised length of pipeline loop starting at Savona compressor station (Alternative 4) required to meet capacity needs. If FEI has not determined a revised length of pipeline loop starting at Savona compressor station, please explain why not.

12.1.1 Please explain whether this revised pipe length triggers an Environmental Assessment (EA).

12.1.1.1 If an EA is not triggered, please explain whether FEI considers Alternative 4 to be feasible.

Response:

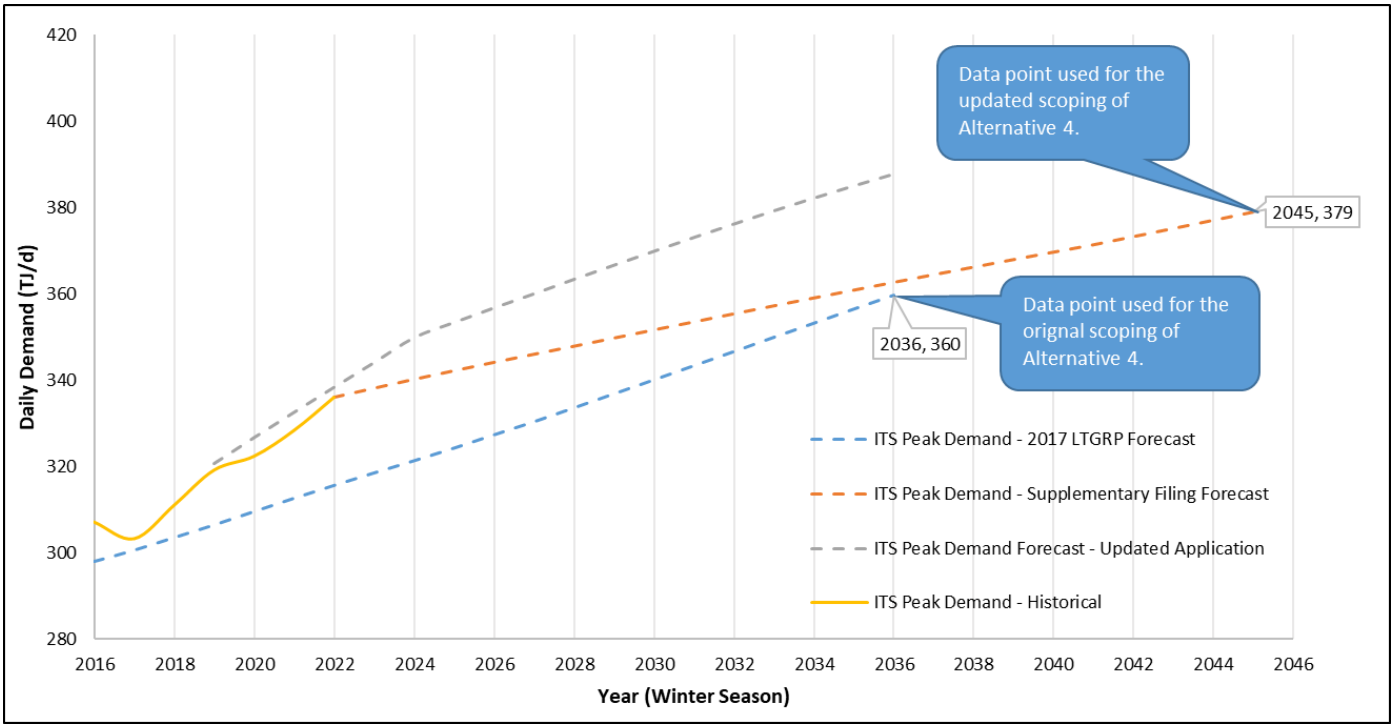
FEI re-scoped Alternative 4 based on the Supplementary Filing Forecast and on meeting the 20-year planning horizon relative to FEI's updated required OCU Project in-service date of 2026. This corresponds to scoping the alternative to meet the Winter 2045/46 peak demand load forecast by the Supplementary Filing Forecast. Based on these parameters, FEI determined the revised pipeline loop length to be approximately 70.4 km of 508 mm diameter pipeline (i.e., an increase of approximately 2 km compared to the original scoping of Alternative 4).

FEI provides the following explanation for why the pipe length has increased even though the Supplementary Filing Forecast shows a reduced future peak demand when compared to the Updated Application Forecast.

FEI determined the original scoping of Alternative 4 in 2018 based on FEI's 2017 LTGRP forecast and meeting the forecast peak demand load in Winter 2036/37. Alternative 4 was screened out early in the development process for reasons relating to its length (i.e., the cost and associated timing of execution). As the Updated Application Forecast showed a higher forecast than what was used to originally scope Alternative 4 (i.e., the 2017 LTGRP forecast), the additional length required would have amplified the issues relating to its length, and so re-scoping was not pursued given that Alternative 4 was not considered to be feasible.

For further context, FEI provides the following figure which compares the 2017 LTGRP Forecast, the Updated Application Forecast, and the Supplementary Filing Forecast. When comparing the scoping associated with the initial (2017 LTGRP) and the Supplementary Filing Forecast, FEI observes that the forecast peak demand in the updated scoping case (i.e., the peak demand per the Supplementary Filing Forecast in Winter 2045/46) exceeds the forecast peak demand in the original scoping case (i.e., the peak demand per the 2017 LTGRP Forecast in Winter 2036/37), resulting in additional pipeline length being required to meet the capacity need.

With the revised pipeline length of 70.4 km, the combination of length and diameter still trigger an environmental assessment.



12.1.2 Please provide a table indicating what the anticipated inlet pressures would be at peak demand conditions at each major gate station of the ITS for each year between 2023 and 2039 if this pipeline were to be installed. If FEI is unable to provide the requested table, please explain why not.

Response:

As described in the response to BCUC Supplementary IR1 12.1, given that the pipeline length for Alternative 4 is longer under the requirements of the Supplementary Filing Forecast, it remains an infeasible alternative. Considering that updating the table in the preamble requires a significant amount of effort and time to produce and Alternative 4 remains infeasible, FEI respectfully declines to provide the information.

12.1.3 Please clarify whether the installation of a new pipeline loop under Alternative 4 would require additional upgrades in the future to continue

to maintain the inlet pressures to the major gate stations in the ITS above the 350 psig minimum requirement. If so, please describe the upgrades that would be required as well as the expected year of installation.

Response:

Please refer to the responses to BCUC Supplementary IR1 12.1 and 12.1.2. Given that the revised pipeline length is longer than that described in the Updated Application, further analysis has not been conducted on Alternative 4, including the prospective need for additional upgrades.

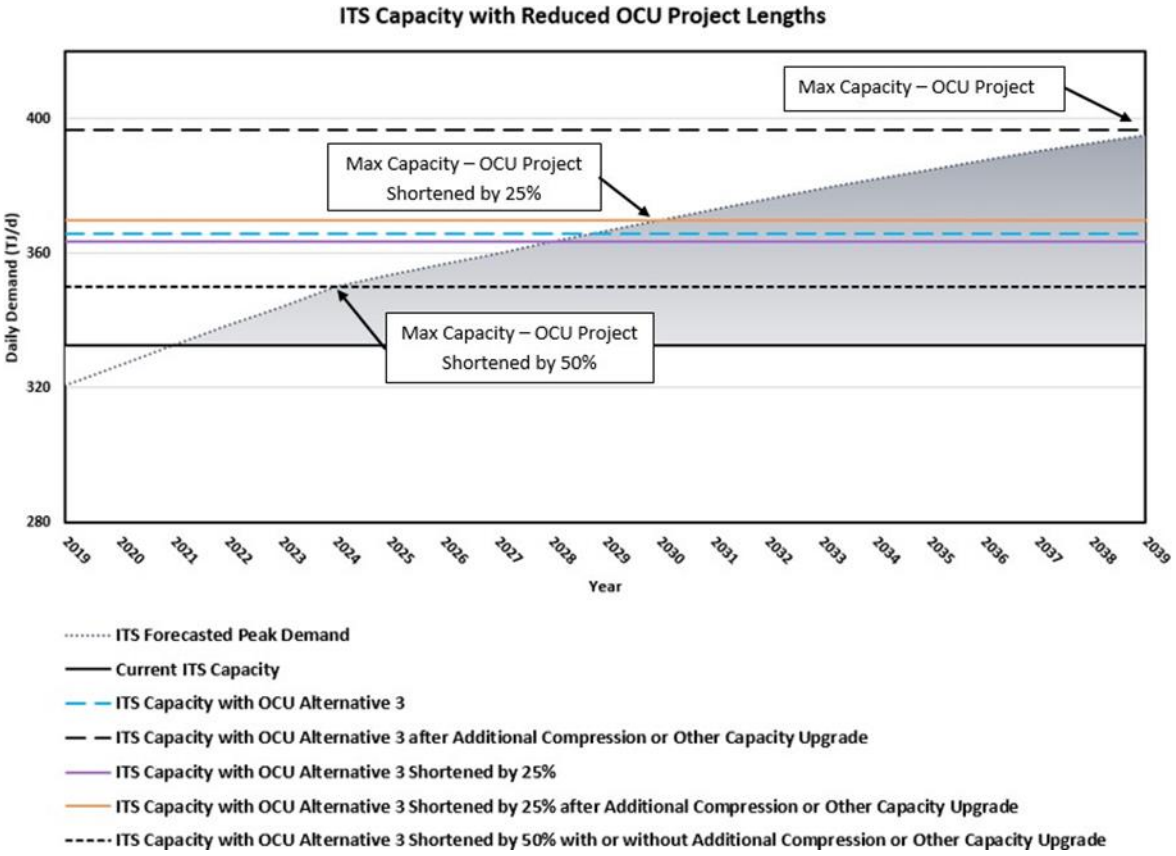
13.0 Reference: DESCRIPTION AND EVALUATIONS OF ALTERNATIVES

Exhibit B-2, BCUC IR 18.1; Exhibit B-35, p. 4; Exhibit B-14, BCUC IR 50.1, 60.3

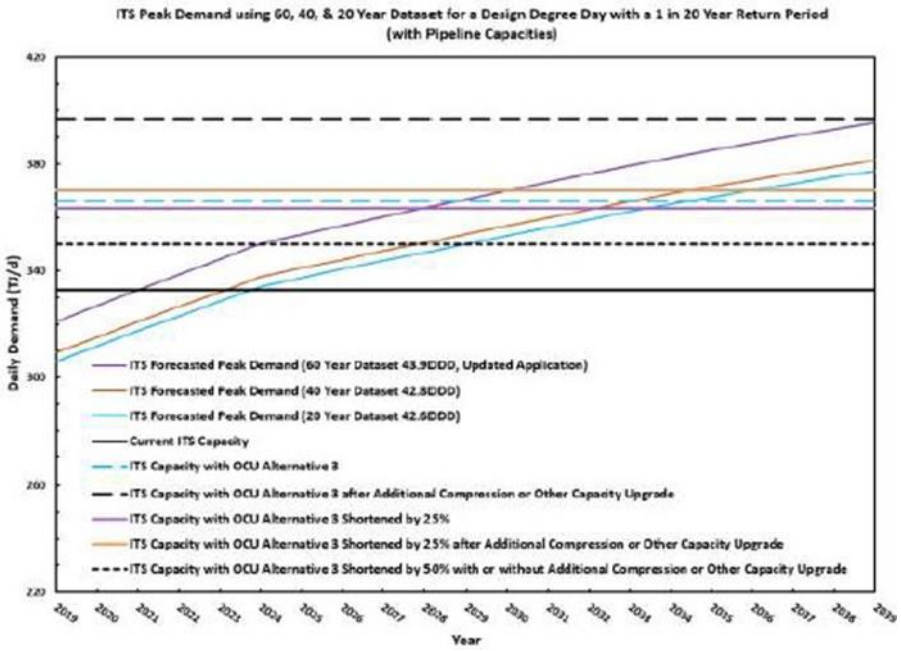
ITS Capacity with OCU Project (OLI PEN 406 Extension)

In response to BCUC IR 18.1, FEI stated:

> The objective of the proposed pipeline is to overcome the capacity restriction in the VER PEN 323 pipeline between Penticton and Kelowna by moving the pressure control station (currently at Ellis Creek in Penticton) supplying gas into the pipeline at 750 psig to a point far enough north to provide the required capacity. FEI determined a project scope for Alternative 3 that could meet or exceed the current 20-year forecast and which could be built on with complementary projects to meet demand growth beyond the forecast horizon. To provide sufficient capacity to exceed the 20-year forecast, the point for supplying gas into the VER PEN 323 pipeline at 750 psig needed to be 28 kilometres north of the current location. In response to BCUC IR 50.1, FEI provided the graph below which illustrates ITS capacity with reduced OCU Project pipeline lengths and ITS forecasted peak demand in FEI's Updated Application.



In response to BCUC IR 66.3, FEI provided the following graph:



On page 4 of the Supplementary Filing, FEI provides Figure 2-1 illustrating the change in ITS forecasted peak demand between FEI's Updated Application and FEI's Supplementary Filing.

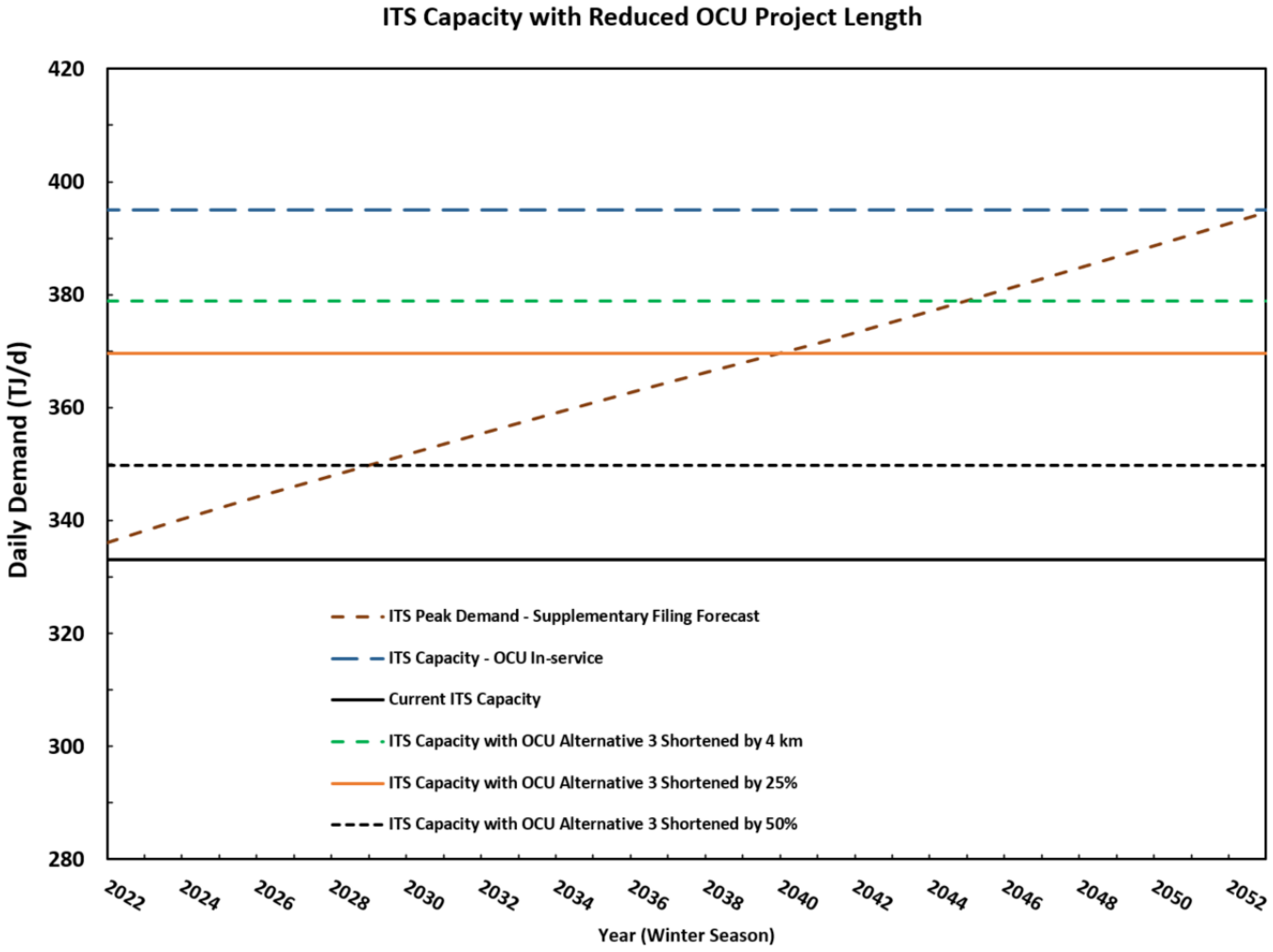
13.1 Please provide graphs similar to those in BCUC IR 50.1 and 66.3 showing the 2022 peak demand forecast for the ITS as outlined in the Supplementary Filing.

Response:

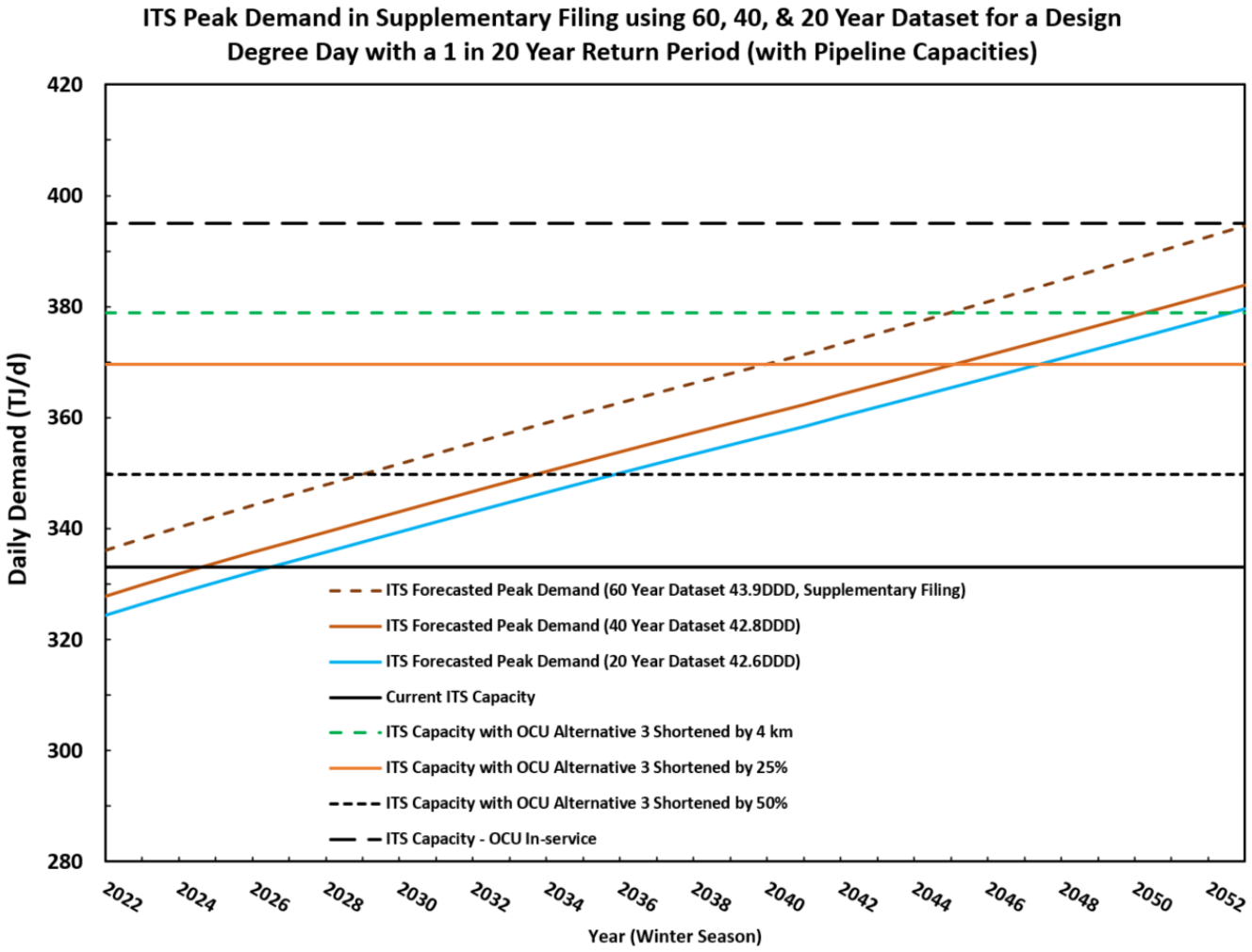
The figures referenced in the preamble have been updated with the Supplementary Filing Forecast and are shown below. Please refer to the response to BCUC IR Supplementary IR1 13.2 for a discussion of the impacts and a comparative table.

As explained in the response to BCUC Supplementary IR1 1.10, with the revised tap pressure assumption at Yahk, compression no longer constrains capacities in relation to the OCU Project, so the below figures no longer have the capacity lines without compression upgrades and show only capacities associated with varying pipeline lengths for Alternative 3.

The figures have also been updated with curves that show Alternative 3 "Shortened by 4 km". These curves correspond to the pipeline length discussed in the response to BCUC Supplementary IR1 13.2 that meets the 20-year peak demand requirement of the Supplementary Filing Forecast.


ITS Capacity with Reduced OCU Project Length
Daily Demand (TJ/d)
420
400
380
360
340
320
300
280
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
2052
Year (Winter Season)
ITS Peak Demand - Supplementary Filing Forecast
ITS Capacity - OCU In-service
Current ITS Capacity
ITS Capacity with OCU Alternative 3 Shortened by 4 km
ITS Capacity with OCU Alternative 3 Shortened by 25%
ITS Capacity with OCU Alternative 3 Shortened by 50%

1



13.2 Please discuss whether the OCU Project with a reduced pipeline length (either with or without additional compression and other capacity upgrades) could provide sufficient capacity to meet the 20-year peak demand forecast in the Supplementary Filing.

13.2.1 If yes, please discuss whether there is an opportunity for FEI to reduce OCU Project costs by reducing the length of the pipeline, while still meeting the primary project objectives, and explain whether FEI has considered revising the OCU Project scope accordingly. Please quantify any potential cost impacts resulting from reducing the OCU Project pipeline length to meet the forecasted demand in the Supplementary Filing, detailing all assumptions made.

Response:

Under the Supplementary Filing Forecast, the OCU Project will provide sufficient capacity for more than a 20-year period. If FEI were to revise the OCU Project scope to have a 20-year horizon based on the Supplementary Filing Forecast, then the required pipeline length would reduce from approximately 30 km to approximately 26 km. However, while reducing the pipeline length by 4 km is feasible, FEI does not recommend this approach and continues to consider the Proposed Project to be the best alternative for customers.

FEI estimates a potential savings of approximately $25.6 million[15] by reducing the required pipeline length by 4 km. Based on this approach, the Chute Lake Control Station would be relocated approximately 4 km upstream of the proposed site. Please refer to the response to BCUC Supplementary IR1 13.2.2 for all other assumptions related to the cost savings calculation.

In Table 1 and Figure 1 below, FEI provides context regarding the potential reductions in length for the OCU Project, as described here and in the response to BCUC Supplementary IR1 13.1. This context includes how the potential changes in OCU Project length will impact the capacity benefit from the OCU Project on the ITS. As Table 1 shows, if the OCU Project is shortened by 4 km, there will be a change in Project cost of approximately 7.8 percent; however, the corresponding change in incremental capacity is a decrease of 26 percent, indicating that the decrease in Project cost is more than offset by the reduction in benefits gained from the incremental capacity. Where the potential length change continues to meet the OCU Project Objective, the change in OCU Project cost is also included. FEI notes that the values in the table are approximations.

Table 1: Comparison of OLIPEN Extension Lengths

OCU Project	Total Length (km)	Reduction in Length from Proposed (km)	Change in Incremental Length (%)	Change in Incremental Capacity [16]	Does it meet Project Objective?	Change in Project Cost
As Proposed	30	0	0%	0%	Yes	0
Shortened by 4km	26	4	-13%	-26%	Yes	-7.8%[17]
Shortened by 25%	22.5	7.5	-25%	-42%	No	Not Applicable
Shortened by 50%	15	15	-50%	-73%	No	Not Applicable
No Project	0	30	-100%	-100%	No	Not Applicable

[15] FEI notes that the levelized delivery rate impact over the 70-year analysis period of the $25.6 million in Project capital cost savings is minor, at approximately 0.14 percent, which is equivalent to savings of approximately $0.63 per year for the average residential customer consuming 90 GJ per year.

[16] Capacity Benefit for each was calculated by subtracting the Current ITS Capacity from the ITS Capacity for each variation of the OCU Project. The percent difference was then taken from the variations when compared to the as-proposed Project.

[17] Please see the response to BCUC Supplementary IR1 13.2.2 for details on cost savings.

Figure 1: Map Depicting Approximate Endpoints of the Various Project Length Reduction Scenarios

While reducing the pipeline length by 4 km is feasible, FEI does not recommend this approach and continues to consider the Proposed Project to be the best alternative for customers. Despite the lower forecast peak demand curve shown in the Supplementary Filing Forecast, and as described in the response to BCUC Supplementary IR1 1.3, there will continue to be year-to-year variability in the peak demand forecasts, and the next year's peak demand forecast could be closer to the Updated Application Forecast. This possibility is borne out in the peak demand forecast curve provided in response to BCUC Supplementary IR1 1.8 (i.e., the green curve). FEI expects that future forecasts for the ITS will be higher than the Supplementary Filing Forecast, based in part on the 2022 year-end data that FEI has provided and discussed throughout the BCUC Supplementary IR1 1, 2 and 3 series, but also when considering the most recent CBOC housing starts forecast now publicly available. Notably:

- The latest CBOC housing starts forecast for single and multi-family dwellings which will be used in development of the 2023 Peak Demand Forecast is much more robust than that which was used to develop the 2022 Peak Demand Forecast. That, coupled with the 2022 customer additions for RS 1 being approximately 22 percent higher than 2021, which is the seed value for the forecast growth, is expected to drive a higher forecast growth in RS 1 peak demand. RS 1 contributes approximately 50 percent of the total peak demand.

- The 2022 UPC_{peak} values, as shown in the response to BCUC Supplementary IR1 3.3, increased relative to 2021. Since a three-year rolling average of UPC_{peak} is used, this will put directionally upward pressure on the UPC_{peak} values used in the development of the 2023 Peak Demand Forecast, and to the extent the 2023 UPC_{peak} values are higher yet, it will further contribute to higher peak demand.

In consideration of the above, FEI does not consider reducing the pipeline length by 4 km to be the best approach. Thus, FEI still proposes construction of the original pipeline length (30 km) and diameter (406 mm)[18], as described in Section 5 of the Updated Application.

13.2.2 Please discuss the extent to which cost savings are proportional to the reduction in length of the OCU Project pipeline, with a description of supporting assumptions.

Response:

Based on the updated 2023 cost estimate provided in the Supplementary Filing, the potential cost savings are approximately $6.4 million per kilometre of the OCU Project pipeline for reductions of relatively short segments (i.e., <5 km). This includes the Pipeline Construction and Materials (minus HDD), Pipeline Engineering, Contingency and Escalation for the 29.89 km pipeline.

The estimated savings exclude Facilities Construction and Materials, Facilities Engineering, Project Services (Project Management, Permitting, Procurement, Environmental and Archaeological), On-Site Inspection Services, Owner's Costs, CPCN Application Costs, and Project Development Costs, as these components of the OCU Project cost would not change if the OCU Project pipeline scope was reduced by less than 5 km. If long reductions (>5 km) are contemplated, there would be significant changes to the scheduling and project execution duration that would require re-evaluation of these excluded costs.

13.2.3 Please discuss whether there is a minimum pipe length required for the project to be technically feasible.

Response:

Please refer to the response to BCUC Supplementary IR1 13.2.

[18] Please refer to the response to BCUC IR1 18.1 for FEI's explanation on why a 406 mm diameter was selected.

D. PROJECT DESCRIPTION

14.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.6, pp. 67 – 68 Procurement

On pages 67 and 68 of the Application, FEI states:

> Material required for the Project which have long lead times to fabricate and deliver include items such as line pipe and block valves. Prior to the receiving CPCN approval, FEI will procure all of the long lead material required in order to commence the early works construction in Q1, 2022. Where applicable, FEI will secure the remaining long lead material required for the Project through the contracts established for the early works.

14.1 Please discuss whether FEI has or intends to procure any long lead material such as line pipe and block valves for the OCU Project prior to receiving BCUC's decision.

14.1.1 If yes, please discuss any potential risks to ratepayers associated with procuring the material if the Project is not approved.

Response:

While FEI had originally intended to take the approach of procuring long lead material prior to receiving BCUC approval (as described in the Original Application and in the above preamble), as the proceeding progressed, it became clear that the timing of when a BCUC decision might be received on the OCU Project would be later than FEI had anticipated. Therefore, in consideration of the uncertainty around when a decision might be issued and the longer than expected timeframe of the regulatory process (i.e., the delays created by the adjournment of the proceeding), FEI did not consider it reasonable to commence the procurement of long lead material.

FEI does not currently plan to procure long lead material prior to receiving BCUC approval. The schedule found in Section 3.4 of the Supplementary Filing shows long lead material items being procured between April and September 2024, which is assumed to be subsequent to receiving BCUC approval for the OCU Project.

15.0 Reference: PROJECT DESCRIPTION

Exhibit B-35, Section 3.4, Table 3-2, p. 11; Exhibit B-1-2, Section 5.4.4, p. 74; Exhibit B-2, BCUC IRs 30.2, 30.3; Exhibit B-14, BCUC IRs 56.2, 56.4.1-56.4.2, 56.8, 56.9, 56.11

Pipeline Deactivation

On page 74 of the Updated Application, FEI states:

> A 1,200 m section of the existing OLI PEN 406 will be deactivated between the Ellis Creek tie-in point and the existing Ellis Creek Pressure Control Station.

On page 11 of the Supplementary Filing, FEI provides Table 3-2 showing the preliminary OCU Project execution schedule with an expected project close out date of March 2027.

Further in response to BCUC IR 56.9, FEI stated:

> […] Deactivation of this section of the pipeline is expected to occur in 2023 or 2024, after construction of the OCU Project is complete.

15.1 Please confirm, or explain otherwise, whether FEI believes that pipeline deactivation of the section of the existing OLI PEN 406 will occur in 2027, following the revised expected completion of the OCU Project.

Response:

FEI confirms that the pipeline deactivation of the section of the existing OLI PEN 406 will follow the revised expected construction phase and full commissioning of the OCU Project and will occur in late 2026 or early 2027.

In response to BCUC IR 56.2, FEI provided the following justification for pipeline deactivation:

> This Section of the OLI PEN 406 pipeline was previously required to connect the OLI PEN 406 pipeline to the VER PEN 323 pipeline at the Ellis Creek Pressure Control Station, thus allowing gas supplied from Oliver to flow north to Kelowna via the VER PEN 323 pipeline. After construction of the new OLI PEN 406 extension, gas will instead flow north through the OLI PEN 13 406 Extension and into the VER PEN 323 pipeline at the Chute Lake Pressure Control Station.

Following completion of the OCU Project, under most operating conditions, little gas would continue to flow north via the VER PEN 323 pipeline from the Ellis Creek Pressure Control Station (SN-10), and therefore the 1,200 metre segment would provide little hydraulic benefit to the system.

Further in response to BCUC IRs 56.4.1 and 56.4.2, FEI considered the following three options for the 1,200 metre section of the OLI PEN 406 pipeline:

1. Continue to use the 1.2 km section of pipeline with gas actively flowing, along with incurring an estimated capital cost of $436 thousand for a new ILI tool launcher/receiver;
2. Deactivate the 1.2 km section of the pipeline as proposed in the Application with an estimated capital cost of $75.5 thousand; and
3. Abandon-in-place the 1.2 km section of the pipeline with an estimated cost of removal of $202 thousand.

15.2 Please confirm, or explain otherwise, that FEI considers pipeline deactivation to be a necessary component of the Project scope.

Response:

Confirmed.

15.3 Please explain, with supporting calculations, whether FEI considers that pipeline deactivation is still the lowest cost option and whether pipeline deactivation would continue to provide significant economic benefits to ratepayers by preserving the ROW, in the context of the Supplementary Filing.

Response:

FEI's position with respect to deactivation remains consistent. As shown in the table below, pipeline deactivation is estimated to be the least cost option with the lowest impact to FEI's ratepayers. The table below also highlights the fact that the deactivation option provides significant benefit to ratepayers by preserving the ROW and therefore potentially avoiding approximately $12 million in costs that would be required for a new pipeline and ROW when compared to the abandonment option.

The deactivated pipeline segment will continue to be used and useful, with the purpose of the segment shifting from actively flowing gas to providing a resiliency and redundancy alternative for the South Okanagan area by being readily available upon reactivation. The examples of

operational flexibility described in the response to BCUC IR2 56.4 continue to be valid with the updated peak demand forecast and construction timing provided in the Supplementary Filing.

The following table summarizes the costs associated with the three options, including the future costs if that segment of pipeline is required in the future, which is applicable to options 2 and 3.

Particulars	Option 1: Continued Use of Pipeline[a]	Option 2: Deactivation[b]	Option 3: Abandon-in-Place[c]
Capital Cost	$489,000	$86,000	$221,000
Future Costs if Pipeline is Required	N/A	Temporary: $86,000 Permanent: $575,000	New pipeline and ROW: $12,000,000
Annual Maintenance Costs	$79,300	$3,800	$0
Retirement Asset Value	N/A	N/A	$670,000

Notes:

(a) Option 1 – Continued Use of Pipeline: The 1.2 km section will also require in-line inspections. FEI estimates the capital costs would be approximately $528 thousand per inspection ($2023) over a 7-year inspection cycle. These future in-line inspection costs are not included in the table above, but they are required under Option 1 if the pipeline remains in-use. The pipeline section will also require similar operations and maintenance activities as outlined in the response to BCUC IR1 30.3.

(b) Option 2 – Deactivation: If the 1.2 km section of the pipeline is required again in the future, FEI estimates the cost of reactivation will be similar to deactivation, which is $86 thousand. If this section of the pipeline is required to be reactivated permanently, then the costs would include reactivation ($86 thousand) plus $489 thousand for a new ILI tool launcher/receiver.

(c) Option 3 – Abandon-in-Place: Abandonment would effectively eliminate the ability to reuse the existing pipeline. The cost to construct a replacement pipeline would be approximately $12 million inclusive of a new ROW.

In response to BCUC IR 30.2, FEI provided the net book value of $670,000 for the section of the pipeline to be deactivated.

Further in response to BCUC IR 56.8, FEI confirmed that the net book value of $670,000 was calculated as of December 31, 2023.

15.4 Please provide the updated net book value of the section of the pipeline to be deactivated at the revised expected deactivation date.

Response:

As explained in the response to BCUC Supplementary IR1 15.1, deactivation of the pipeline section will occur in late 2026 or early 2027 based on the revised expected OCU Project execution

schedule. If the deactivation occurs in late 2026, then the net book value (NBV) of the section of pipeline that is expected to be deactivated as part of the OCU Project would be approximately $610 thousand, calculated as of December 31, 2026 based on FEI's currently approved depreciation rates. If the deactivation occurs in early 2027, then the NBV would be approximately $605 thousand, calculated as of March 31, 2027.

In response to BCUC IR 30.3, FEI stated:

> The deactivation costs for the 1,200 m section of the existing OLI PEN 406 are approximately $80 thousand. […]
>
> Annual ongoing maintenance costs of the deactivated section of the existing OLI PEN 406 are approximately $3.5 thousand per year. […]

Further in response to BCUC IR 56.11, FEI provided Table 1 showing the breakdown of the cost estimate for pipeline deactivation.

15.5 Please provide the updated total cost estimate for pipeline deactivation costs and annual ongoing maintenance costs.

Response:

Please refer to Table 1 below for the updated cost estimate of the pipeline deactivation in 2023 dollars for the 1.2 km section of OLI PEN 406 pipeline with the same breakdown as provided in the response to BCUC IR2 56.11.

Table 1: Deactivation Activities

Activity	Breakdown	Estimate
Purge line to complete deactivation	• Install fittings for purging activities at the south tie-in location and Ellis Creek Pressure Control Station • Perform purging activities	$6,900
Isolation at south tie-in location	• Remove section of OLI PEN 406 pipeline • Prepare pipe end for weld • Install and weld cap	$17,100
Isolation at Ellis Creek Pressure Control Station	• Remove pipe appurtenances • Prepare pipe end for installation of blind flange • Install blind flange	$28,600
Nitrogen blanket	• Install gauges and fittings for nitrogen blanket monitoring • Complete final deactivation activities	$33,400
TOTAL		**$86,000**

As previously discussed in the response to BCUC IR1 30.3 and updated to 2023 dollars, annual ongoing maintenance costs of the deactivated section of the existing OLI PEN 406 are approximately $3.8 thousand per year. This segment of pipe would be managed under applicable FEI standards and guidelines, including right-of-way patrol and inspections, vegetation management, third-party driven inspections, nitrogen blanket pressure inspection and calibration, and cathodic protection testing and maintenance.

E. PROJECT COST

16.0 Reference: PROJECT COST

Exhibit B-35, Section 3.2, pp. 7-8; Section 3.3, Table 3-1, p. 9; Exhibit B-1-2, Section 4.4, Table 4-2, p. 46; Section 4.6.3.1, Table 4-7, p. 55; Section 4.7, p. 57; Exhibit B-2, BCUC IR 32.1

Project Cost Estimate

On page 9 of the Supplementary Filing, FEI provides Table 3-1 showing the total updated OCU Project cost estimate for the Supplementary Filing as compared to the Updated Application:

Table 3-1: Summary of Forecast Capital and Deferred Costs ($ millions)

Line	Particular	Updated Application ($Millions)	Supplementary Filing ($Millions)	Change
1	Construction Cost Estimate (Contractor)	153.486	176.969	23.483
2	Owner's Costs (FEI)	25.137	35.855	10.718
3	Inspection Services (FEI)	8.637	8.689	0.052
4	AC Mitigation, Cathodic Protection, Deactivation (FEI)	0.700	0.755	0.055
5	**Subtotal Construction Capital Cost Estimate**	**187.960**	**222.268**	**34.308**
6	Contingency	25.100	28.400	3.300
7	Cost Escalation Estimate	11.611	10.185	(1.426)
8	**Subtotal w/ Contingency & Escalation**	**224.671**	**260.853**	**36.237**
9	CPCN Application Costs	0.400	0.555	0.155
10	Project Development Costs	7.864	17.706	9.841
11	**Subtotal w/ Application and Development Costs**	**232.935**	**279.114**	**44.807**
12	Management Reserve	23.600	27.800	4.200
13	AFUDC	16.834	22.969	6.136
14	Income Tax Recovery	(2.034)	(2.473)	(0.439)
15	**Total Project Cost Estimate (As-Spent)**	**271.335**	**327.410**	**54.704**

16.1 Please confirm, or explain otherwise, that there is a calculation error in Table 3-1, specifically in Lines 8 and 11 of the 'Change' column. If confirmed, please provide a revised table.

Response:

FEI confirms that Table 3-1 contains some calculation errors in the "Change" column. Specifically, the "Change" column on Line 8 should be the sum of Lines 5 to 7; however, Line 4 was inadvertently included in the summation formula in excel. Similarly, the "Change" column on Line 11 should be the sum of Lines 8 to 10; however, Line 7 was inadvertently included in the summation formula in excel. These two errors also resulted in the Total Project Cost Estimate under the "Change" column, i.e., Line 15, being incorrect because the summation is based on Line 11.

Please refer to Table 1 below which provides a revised Table 3-1 with the corrected values in the "Change" column for Lines 8, 11 and 15.

Table 1: Revised Table 3-1 – Summary of Forecast Capital and Deferred Costs ($ millions)

Line	Particular	Updated Application ($Millions)	Supplementary Filing ($Millions)	Change
1	Construction Cost Estimate (Contractor)	153.486	176.969	23.483
2	Owner's Costs (FEI)	25.137	35.855	10.718
3	Inspection Services (FEI)	8.637	8.689	0.052
4	AC Mitigation, Cathodic Protection, Deactivation (FEI)	0.700	0.755	0.055
5	**Subtotal Construction Capital Cost Estimate**	**187.960**	**222.268**	**34.308**
6	Contingency	25.100	28.400	3.300
7	Cost Escalation Estimate	11.611	10.185	(1.426)
8	**Subtotal w/ Contingency & Escalation**	**224.671**	**260.853**	**36.182**
9	CPCN Application Costs	0.400	0.555	0.155
10	Project Development Costs	7.864	17.706	9.841
11	**Subtotal w/ Application and Development Costs**	**232.935**	**279.114**	**46.179**
12	Management Reserve	23.600	27.800	4.200
13	AFUDC	16.834	22.969	6.136
14	Income Tax Recovery	(2.034)	(2.473)	(0.439)
15	**Total Project Cost Estimate (As-Spent)**	**271.335**	**327.410**	**56.075**

On page 7 of the Supplementary Filing, FEI states:

> The following assumptions were used in preparing the updated estimate:
>
> - […] The production rates assumed for contractors in 2020 remained the same […]

16.2 Please explain, with supporting rationale, why FEI believes that the production rates assumed for contractors in 2020 are still relevant in the context of the Supplementary Filing.

Response:

The key factors influencing production rates or productivity for major work activities are project specific and are not impacted by the passage of time unless, in general, there are technological advances, changes in tools and equipment and improvements to working conditions. In the case of the OCU Project, none of these factors have changed. Some common examples of project-specific factors are project location, the route of the pipeline, weather, geologic and soil characteristics, means and methods, and quantity of work. In the case of the OCU Project, as noted in the Supplementary Filing, "the alignment of the pipeline route and the construction approach described in the Updated Application remained the same." As such, there is no change

in any of the influencing project-specific factors that would impact production rates for the major activities on the OCU Project.

On page 7 of the Supplementary Filing, FEI states:

> FEI has two comparable pipeline projects:
>
> - The Inland Gas Upgrade (IGU) project which started in 2020 and is scheduled for completion in 2024; and
> - The Eagle Mountain Gas Pipeline (EGP) project which is scheduled to begin construction in 2023.
>
> One of the contractors engaged for both of the above projects provided bids in 2023$ for equipment and labour resources which can be used as a basis to estimate costs for other pipeline construction projects. As such, FEI has used the updated rates for both labour and equipment for the OCU Project as they reflect current market conditions and union labour rates.

16.3 Please explain why the projects mentioned above provide a reasonable comparison to the OCU Project, for the purposes of estimating costs.

Response:

The EGP and IGU projects provide a reasonable comparison to the OCU Project for the purposes of estimating costs because the project types and locations have similar characteristics. For example, the EGP project has a pipeline component located in mountainous terrain and will utilize similar construction means and methods as planned for the OCU Project. With regard to the IGU project, there are four pipeline replacements located in Northern BC in mountainous terrain that are part of the project's scope. Since the crews and equipment are similar for the three projects and the OCU Project is situated in mountainous terrain, the contractor's means and methods will be similar.

16.4 Please provide a detailed justification for why FEI considers that bids received from a single contractor would be a reasonable approach toward updating labor and equipment rates. As part of the response, please discuss whether FEI considered

obtaining bids from multiple contractors, and why this approach was ultimately not pursued.

Response:

FEI clarifies that it did not obtain bids from a contractor for the OCU Project itself, but instead used bids from two recent projects (i.e., the EGP and IGU projects) to inform the updated labour and equipment rates for the OCU Project. Also, bids were not obtained because the estimate was completed at a Class 3 level which means that the OCU Project design is only approximately 30 percent complete, and the maturity of the project deliverables are inadequate to inform firm contractor bids.

The bids received for the IGU and EGP projects were received in two forms. For the EGP project, the bid was received through an Early Contractor Involvement (ECI) procurement process. As part of that process, the contractor provided labour and equipment rates, which were compared and validated to current market rates by an independent consulting firm and subsequently agreed to through negotiations. For the IGU project, bids were received as part of a competitive tendering process. These bids were evaluated and the contractor with the most competitive offer, considering other evaluation factors, was selected. In addition, the rates in the bids were compared to previous years' bids to assess areas where changes occurred to ensure the rates reflected market conditions. Effectively, therefore, the rates used in the analysis to update the OCU Project cost estimate provide the best indicator of current market pricing for both labour and equipment rates and reflect rates obtained through a competitive bidding process.

16.5 Please explain how the bids received from the contractor engaged in the IGU and EGP Projects were used to estimate labor and equipment rates for the OCU Project.

Response:

When responding to this IR and to BCUC Supplementary IR1 16.6, FEI discovered an error in its description in Section 3.2.2 of the Supplementary Filing regarding the calculation of the OCU Project rates. Specifically, in the Supplementary Filing and as provided in the preamble, FEI stated the following:

> FEI determined that five different crew rates and seven different equipment rates totaled over 80 percent of the total labour and equipment costs respectively. For each of these labour and equipment rates, the 2023 unit rates used in the IGU and EGP projects were reviewed and the average of the two rates was computed. [Emphasis added]

The sentence should have stated: "…ten different crew and equipment rates totaled over 80 percent of the total labour and equipment costs. For each of these labour and equipment rates, the 2023 unit rates used in the IGU and EGP projects were reviewed and an adjusted rate was computed".

The above error does not impact the OCU Project cost provided in the Supplementary Filing or the conclusions drawn from the analysis.

The OCU Project rates were analyzed to establish which of the labour and equipment rates contributed the most to the cost estimate. It was determined that the top 10 contributors for both labour and equipment represented approximately 80 percent of the total labour and equipment costs. These top 10 rates for both labour and equipment were compared to the IGU and EGP projects' data sets. For labour, there were nine exact matches within the data sets, and for equipment type there were four exact matches. To provide a more accurate mathematical average calculation of change, the IGU and EGP project data sets were further examined to find other comparable labour and equipment rates. In total, 14 labour rates and 10 equipment rates matched exactly and were used in the computation.

The following table provides the data set used for computing the average overall labour increase of approximately 8.9 percent.

Table 1: Calculation of Labour Rate Increase

Labour Resource	Rate Unit	IGU Rate	EGP Rate	Average 2023 Rate	Original Solaris Rate	Adjusted Rate
Construction Manager	$/Day	2,299.68	2,564.03	2,431.85	1,800.00	1,959.36
Cost Controller	$/Day	1,339.52	1,415.87	1,377.70	1,200.00	1,306.24
Document Controller	$/Day	556.96	1,117.80	837.38	1,128.00	1,227.86
Equipment operator	$/Day	1,206.16	1,024.88	1,115.52	1,250.90	1,361.64
First Aider	$/Day		783.84	783.84	1,000.00	1,088.53
Fitter	$/Day	2,407.10	1,811.93	2,109.51	1,685.94	1,835.20
Fitter c/w Rig	$/Day	2,878.28	1,676.69	2,277.49	2,064.76	2,247.56
Foreman	$/Day	2,468.36	2,192.35	2,330.35	1,301.17	1,416.36
Laborer	$/Day	1,063.46	667.92	865.69	1,021.88	1,112.36
Skilled Laborer	$/Day		783.84	783.84	1,128.00	1,227.86
Spread Boss	$/Day	2,325.00	2,932.49	2,628.74	1,800.00	1,959.36
Truck Driver	$/Day		1,101.24	1,101.24	1,176.08	1,280.20
Welder	$/Day		1,676.69	1,676.69	1,688.21	1,837.67
Welder - helper	$/Day		812.82	812.82	1,168.93	1,272.42
			Total	21,132.65	19,413.86	21,132.65
				Overall increase	8.9%	

After the labour resources and rate units were identified, the corresponding rates from both the IGU and EGP projects were identified, and an average 2023 rate was calculated. In some

instances, only a single value was available so in those cases the single value was used as the average 2023 rate. The overall increase of approximately 8.9 percent was determined by summing each of the average 2023 rates and computing the total percentage change from the sum of the corresponding original Solaris' rates (from 2020) by simple division. The overall average increase was then applied to each labour resource contained within the cost estimate, including those shown in the table.

The following table provides the data set used for computing the average overall equipment increase of approximately 8.8 percent.

Table 2: Calculation of Equipment Rate Increase

Equipment Resource	Rate Unit	EGP Rate	Original Solaris Rate	Adjusted Rate
140H Grader	$/Day	1,452.00	1,140.00	1,240.61
3 ton Truck with Picker	$/Day	704.20	620.00	674.72
30 Ton Rock Truck	$/Day	1,942.50	1,760.00	1,915.32
330 Cat Excavator	$/Day	1,216.87	1,090.00	1,186.19
450CT Case Track Loader	$/Day	833.46	880.00	957.66
583 Cat Sideboom	$/Day	1,762.50	1,680.00	1,828.26
D6 Dozer	$/Day	1,814.01	1,510.00	1,643.26
D8 Dozer	$/Day	2,381.00	2,210.00	2,405.03
D9Dozer	$/Day	2,622.50	2,870.00	3,123.28
F350 Crew Truck with Picker	$/Day	920.00	620.00	674.72
	Total	15,649.04	14,380.00	15,649.04
		Overall increase	8.8%	

Table 2 above shows only the EGP project's equipment resource rates because the IGU project's equipment resource rates included costs for a driver and diesel fuel. The driver and diesel fuel costs were not applicable to the OCU Project and could not be separated from the other IGU project resource rates; therefore, FEI did not include the IGU project equipment rates in the calculation.

The overall increase of 8.8 percent was determined by summing the EGP project's equipment rates and computing the total percentage change from the sum of the original Solaris' equipment rates (from 2020) for the corresponding equipment by simple division. The overall average increase was then applied to all equipment resources contained within the cost estimate, including those shown in the table.

This approach maintains the validity of the Solaris estimate basis and is consistent with how the inflation metric is computed by analyzing the net impact on prices rather than focusing on individual items.

On page 8 of the Supplementary Filing, FEI states:

> […] FEI determined that five different crew rates and seven different equipment rates totalled over 80 percent of the total labour and equipment costs respectively. For each of these labour and equipment rates, the 2023 unit rates used in the IGU and EGP projects were reviewed and the average of the two rates was computed. The average change in labour rates was an approximately 8.9 percent increase and the average change in equipment rates was an approximately 8.8 percent increase. These percent increases were applied to each of the labour and equipment resource rates in the estimate. This maintains the validity of the original estimate basis as it is consistent with how the inflation metric is computed by analyzing the net impact on prices rather than focusing on individual items. [*Emphasis added*]

16.6 Please compare the 2023 labour rates and equipment rates applied to the OCU Project, with the 2023 unit rates and original unit rates for labor and equipment from the IGU and EGP Projects.

Response:

Please refer to the response to BCUC Supplementary IR1 16.5.

16.7 Please explain why computation of an average of the 2023 unit rates used in the IGU and EGP projects for estimating the labor and equipment costs of the OCU Project is justified, considering the differences in timelines between the three projects. As part of the response, please discuss whether FEI considered an alternate approach(es) and provide numerical data supporting the same. If no alternative approach(es) was considered, please explain why not.

Response:

FEI considers using the rates for both the IGU and EGP projects to be a reasonable approach because they are based on contracts that have been executed or will be executed in 2023 and thus reflect the current market rates for labour and equipment. In the case of the IGU project, even though work started in 2022, the work is being completed in phases with the pipeline replacement component currently underway.

FEI averaged the rates from the IGU and EGP projects because this approach provides a single value that represents the combined effect of two values, thereby providing values for each rate that are more representative of the current market rates for labour and equipment.

FEI did not consider an alternative approach because averaging of two values that represent the same variable or factor and have the same units (in this case currency) is the best mathematical method to arrive at a midpoint value.

16.8 Please elaborate on why FEI believes it is reasonable to apply labor and equipment rate increases from the IGU and EGP projects to the overall labor and equipment cost respectively for the OCU Project, instead of analyzing each cost element within labor and equipment individually.

Response:

Analyzing each cost element individually would require a large data set that had all the labour and equipment rates consistently arranged for each of the three projects. The labour and equipment types used by different contractors and consultants on any project varies based on the scope, location and characteristics of the work; therefore, obtaining data to update each line item is not available unless formal bids or a reference data set is available. There are, however, similarities in the unit costs amongst the three projects because of similar scope and it was determined that approximately 80 percent of the OCU Project estimate was driven by the 10 labour and equipment rates which were similar. In circumstances such as this where a small sample size has such a large impact on the total cost estimate, analyzing each cost element would not significantly improve the accuracy of the cost estimate.

On page 8 of the Supplementary Filing, FEI states:

[…] First, an analysis was performed to determine the most impacted subcontracts to the estimate. FEI determined that four subcontractors met the criteria: blasting, clearing and grubbing, non-destructive testing and the Penticton Horizontal Directional Drill. Subsequently, FEI obtained updated quotations from contractors' 2020 quotations. […]

For all other subcontractors the annual BC CPI [consumer price index] index of an approximately 9.9 percent increase from 2020 to 2022 was applied.

16.9 Please provide a summary of all subcontractors included in the OCU Project cost estimate for 2023, and the related costs.

Response:

A portion of this response is redacted pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-72-23. The confidential information has been redacted as it is commercially sensitive information that should remain confidential in perpetuity because, if disclosed, may prejudice negotiations with other parties in the future. The confidential response will be filed with the BCUC under separate cover and will be made available to registered parties with signed Confidentiality Declarations and Undertakings filed on the record in this proceeding.

The following Table 1 captures all of the subcontracted works originally estimated by Solaris Management Consultants Inc. (Solaris or SMCI), updated to reflect 2023 pricing.

Table 1: Subcontracted Works updated for 2023 Pricing

Subcontractor Budget Pricing
[redacted]

Subcontractor Budget Pricing

[redacted]

1
2

16.10 Please provide additional details supporting FEI's analysis to determine the most impacted subcontracts. As part of the response, please provide details pertaining to the criteria applied to identify the four subcontractors, as mentioned above.

Response:

The main subcontracts that contribute to the cost estimate, except for line sweep, are blasting, clearing and grubbing, non-destructive testing and the Penticton Creek Horizontal Directional Drill**.** Collectively, these subcontracts comprise approximately 72 percent of the sub-contractor portion of the cost estimate. As such, the criterion was similar to that used for labour and materials where attention was focused on the elements of the cost estimate which had the largest contribution to the total cost estimate. FEI did not obtain updated costs for line sweep as Solaris used in-house data to estimate the work and did not rely on subcontractor data. Please also refer to the response to BCUC Supplementary IR1 16.9.

16.11 Please discuss how FEI determined that applying the annual BC CPI increase of approximately 9.9 percent to all subcontractors that did not meet the established criteria was reasonable. As part of the response, please explain whether FEI considered any alternate approach(es) to update the subcontractor cost estimate.

Response:

FEI determined that using the annual BC CPI was reasonable because the subcontractors for the OCU Project, and subcontractors in general, will increase their quotes to reflect changes in prices experienced by consumers to ensure that their costs are fully recovered to maintain their profit margins in a competitive environment. Considering that BC CPI tracks the prices of a basket of goods and services that are commonly purchased by consumers, it is the best indicator of price increases when the type of product or good is the same. In the case of the OCU Project, the scope remains the same since the Application was developed, thereby justifying the use of BC CPI to increase the prices of subcontractors that did not meet the established criteria.

FEI did not consider an alternate approach to update the subcontractor cost estimates as the approach taken obtained updated quotes for over 70 percent of the total subcontracted value and the remaining 30 percent was updated to reflect current market trends using BC CPI.

On page 8 of the Supplementary Filing, FEI states:

> FEI obtained updated quotes from vendors for the line pipe and facilities materials. These new values were used in the estimate as direct inputs without any normalizing.

16.12 Please explain whether FEI considered any alternate approach(es) to update the material cost estimate.

Response:

FEI did not consider an alternative approach to update material pricing. FEI obtained vendor quotes because market volatility and supply chain issues, coupled with the residual impact of the COVID-19 pandemic, have impacted raw material availability and inventory levels that have caused material prices to increase significantly above annual inflation levels. As such, obtaining updated quotes from vendors was a prudent approach to update the materials (and the large subcontracts) portion of the cost estimate.

On page 8 of the Supplementary Filing, FEI states:

> The construction estimate for project services and engineering was adjusted by approximately 7.7 percent based on known increases to these services from other recent projects.

16.13 Please provide supporting evidence and calculations for the 7.7 percent escalation rate for the construction estimate for project services and engineering. As part of the response, please provide details on the nature of FEI's recent projects that were considered for the purpose of the estimate.

Response:

FEI incorrectly stated in the Supplementary Filing that it derived the 7.7 percent escalation for project services from its recent projects. Rather, FEI determined that the percentage increase for the Owner's costs is approximately 7.97 percent based on the total estimated salary increases from 2021 to 2023. FEI applied the average percentage increase from 2021 to 2023 to both project services and engineering costs that made up the total Owner's costs. FEI used this approach because the estimated increases to project services and engineering costs are primarily due to salary increases and typically are the same across the industry, with some inherent variations

when there is a labour shortage or changes in market conditions, neither of which currently apply to the OCU Project.

Table 1 below shows the calculation of the 7.97 percent, which is a weighted average of the estimated total salary increases from 2021 to 2023 for Management and Exempt (M&E) employees, IBEW 213 (Electric & Gas) employees, and MoveUP employees. FEI determined that based on activities as well as approximately 118,000 hours of work estimated to be required, the allocations between M&E employees and unionized employees are 80 percent and 20 percent, respectively.

Table 1: Estimated Increase in Owner's Costs for OCU Project in Supplementary Filing

	Estimated Salary Increase (2021 to 2023)	% Allocation	Weighted-Average (%)
M&E	8.4%	80.0%	6.71%
IBEW-E[(1)]	6.6%	6.7%	0.44%
IBEW-G	6.1%	6.7%	0.41%
MoveUP[(1)]	6.1%	6.7%	0.41%
Total		**100.0%**	**7.97%**

Note:

(1) Collective Agreements for IBEW-E and MoveUP for 2023 and beyond are not finalized; therefore, 2023 increases in percentage are assumed to equal 2022 percentage increases.

On page 8 of the Supplementary Filing, FEI states:

> […] the Owner's Costs estimate was analyzed to establish the top contributors to the overall estimate total. The rates for the job titles were compared between the initial FEI 2020 rates and the current 2023 rates, with the average increased applied to all Owner's costs. […]

16.14 Please explain how FEI analyzed the Owner's Costs estimate to identify the top contributors to the overall estimate. As part of the response, please describe the constituent elements of the Owner's Costs estimate.

Response:

FEI determined the top contributing positions by identifying the effort contained within the Owner's costs that were categorized as Management and Exempt staff and how much was categorized as unionized employees, and the respective weight that each of the two categories contributed to the estimate. A weighted average salary increase from 2020 to 2023 was then computed and applied to the various positions contained within the Owner's cost estimate.

FEI considers the above-described approach to be most appropriate for updating the Owner's costs because the weighted average salary increase computed represents the actual increases in salary costs across FEI from 2020 to 2023. FEI did not contemplate any other method to update the Owner's costs. Please also refer to the response to BCUC Supplementary IR1 16.13.

The constituent elements of the Owner's cost estimate are management, unionized staff, supporting consultants, benefits, traveling, and living out allowances.

16.15 Please elaborate on why FEI selected this approach to estimate Owner's Costs. As part of the response, please explain whether FEI considered any alternate approach(es) to update the Owner's Cost estimate.

Response:

Please refer to the response to BCUC Supplementary IR1 16.14.

In response to BCUC IR 32.1, FEI stated:

> The accuracy range of the OCU Project is -5% to 35% at an 80 percent confidence interval of actual costs from the cost estimate.

16.16 Please explain whether there has been any change in the accuracy range of the OCU Project cost estimate.

16.16.1 If yes, please provide the revised range of the cost estimate and confidence interval and discuss why FEI considered it necessary to revise.

Response:

There is only a minor change in the accuracy range for the OCU Project, as described further below.

FEI engaged Validation Estimating LLC to revise the original risk analysis for the OCU Project. This is found in Appendix A-1 of the Supplementary Filing. The accuracy of the cost estimate is determined by analyzing the systemic risk shown in Table 2 in Appendix A-1 and the project-specific risks shown in Table 6 of Appendix A-1. As neither the systemic risks nor the project-specific risks changed, the accuracy range of the revised project cost estimate is very similar to the original estimate.

The accuracy range for the cost estimate in the Application was +19/-16 percent (to one decimal place this range is +18.8/-15.5 percent). In the Supplementary Filing the accuracy range for the cost estimate, stated on page 12 of Appendix A-2 of the Validation Estimating Escalation Report – Revised Final, was computed as +18/-16 percent (to one decimal place this range is +18.4/-15.6 percent). The small changes are due to rounding in the model when running the Monte Carlo simulation.

On page 46 of the Updated Application, FEI provides Table 4-2 showing Preliminary Cost Estimates for all Project Alternatives:

Table 4-2: Preliminary Cost Estimates of All Alternatives

Alternative	Description	Total Pipe Installed (km)	Capital Cost Estimate Range (2019$ millions)
1	ITS Upgrades to VER PEN 323	15	40 – 100
2	Modified ITS Upgrades to VER PEN 323	19	50 – 130
3	OLI PEN 406 Extension	30	100 – 250
4	508 mm Loop from Savona	54	200 – 500
5	LNG Facility Near Vernon	n/a	250 - 600

On page 55 of the Updated Application, FEI provides Table 4-7 showing the Present Value (PV) of Incremental Annual Revenue Requirement and Rate Impact for the three feasible Project Alternatives:

Table 4-7: PV of Incremental Annual Revenue Requirement and Rate Impact

	Alternative 1	Alternative 2	Alternative 3
PV of Annual Revenue Requirement $000s	$199,969	$213,780	$203,973
Levelized Rate Impact $/GJ	$0.057	$0.061	$0.059
Financial / Rate Impact	4	2	3

On page 57 of the Updated Application, FEI states:

As the non-financial evaluation indicated that Alternative 3 would provide the best technical solution, and a financial evaluation indicated that Alternative 3 would also be cost effective as it provides a lower rate impact than Alternative 2 and a small difference in the rate impact to Alternative 1, it is clear that Alternative 3 (i.e., a 30 km extension of the OLI PEN 406 pipeline to Chute Lake, with a new control station to tie into the existing VER PEN 323 pipeline) is the preferred solution. [*Emphasis added*]

16.17 Please update Table 4-7 to reflect the PV of Annual Revenue Requirement reflecting 2023 dollars, for each of the three feasible alternatives.

Response:

FEI has not completed an update to the cost estimates of the other feasible alternatives and therefore is unable to provide an updated Table 4-7 to reflect the PV of Annual Revenue Requirement in 2023 dollars based on updated cost estimates. Updating the cost estimates of Alternatives 1 and 2 would not change the evaluation between the alternatives, and Alternative 3 would remain the preferred option.

As noted in Section 3.1 of the Supplementary Filing, there is no change to the OCU Project due to the passage of time. As such, the primary drivers of the cost increases for Alternative 3 (with updated cost estimates as provided in the Supplementary Filing) are limited to the following:

- Inflationary cost increases in construction labour & equipment, subcontractors, material, and FEI's resource for Owner's costs from 2020 to 2023. These inflationary increases which have occurred since 2020 when the Updated Application was filed are significant and well-documented.
- The additional costs related to FEI's most up-to-date understanding of the requirements in the agreement with Indigenous communities on the OCU Project.

Both of the above-described drivers of the cost increases are applicable to Alternatives 1 and 2, and the magnitude of the increases would be similar. This is because all three alternatives primarily involve pipeline construction; thus, the increases in labour and equipment rates, subcontractor costs, and internal resources for Owner's costs would be similar. Furthermore, the requirements in the agreement with Indigenous communities on the OCU Project would be the same under all of the feasible alternatives. As such, adding the same inflationary cost increases as well as the same requirements in the agreement with Indigenous communities to Alternatives 1 and 2 would not change the financial comparison between the three alternatives. All three alternatives would likely increase by a similar magnitude and Alternative 3 would continue to be the preferred option financially compared to Alternatives 1 and 2 in terms of PV of incremental revenue requirements and levelized rate impacts.

FEI also notes that, as discussed in Sections 4.6.1 and 4.6.2 of the Updated Application, Alternative 3 is technically (non-financially) superior to the other alternatives in terms of asset management capability, project execution, and lifecycle operation. The results of the technical (non-financial) evaluation have not changed with the passage of time, thus Alternative 3 remains the preferred alternative regardless of the updated cost estimate. Please also refer to the response to BCUC IR1 11.1.

16.18 Please explain whether FEI's financial evaluation of the three feasible alternatives in Table 4-7 above would change as a result of an amendment to Table 4-7 for 2023 dollars based upon updated cost estimates for all alternatives, and whether this would result in a change in the overall evaluation of alternatives and selection of preferred alternative.

Response:

Please refer to the response to BCUC Supplementary IR1 16.17.

17.0 Reference: PROJECT COST

Exhibit B-35, Section 3, p. 7

Engineering Consultant

On page 7 of the Supplementary Filing, FEI states that it retained an engineering consultant, Solaris Management Consultants Inc. (SMCI), to complete an AACE Class 3 cost estimate for the construction component of the OCU Project, which in addition to FEI's Owner's Class 3 estimate for project support services and project management, formed the Base Estimate for the OCU Project.

Further on page 7, FEI states: "In March 2023, FEI updated the construction component of the Base Estimate for the OCU Project. The scope of the update was limited to rate increases for labour and materials, and increases to material cost, effectively updating the estimate to 2023$."

17.1 Please explain whether an engineering consultant was engaged to assist FEI in updating the construction component of the Base Estimate for the OCU Project.

17.1.1 If yes, please provide the name of the engineering consultant and describe the consultant's relevant experience and qualifications.

17.1.2 If not, please explain why not.

Response:

FEI retained the services of Joseph Sukhnandan from Sukhnandan Consulting Inc. (a former employee of FortisBC) to assist with updating the construction component of the OCU Project cost estimate. Please refer to Attachment 17.1 for a copy of Mr. Sukhnandan's Curriculum Vitae.

18.0 Reference: PROJECT COST

Exhibit B-35, Section 3.3, pp. 9-10, Section 4.2, Table 4-3, p. 15; Exhibit B-1-2, Section 6.3.2, p. 96; Exhibit B-2, BCUC IR 33.1

Application and Preliminary Stage Development Costs Deferral Account

On page 15 of the Supplementary Filing, FEI provides Table 4-3 showing an updated estimate of Application costs to be incurred, along with actual preliminary stage development costs and pre- construction development costs incurred between March 2018 and March 2023:

Table 4-3: Deferred Application Costs and Preliminary Stage Development Costs ($ millions)

			March 2018 - March 2023 Actual		
Line	Particular	CPCN Application Costs	Preliminary Stage Development	Pre-Construction Development	Total
1	Pre-Tax Costs	0.555	0.902	16.804	18.261
2	Financing, WACC Return	0.024	0.192	1.254	1.470
3	**Subtotal Before Tax Offset**	**0.579**	**1.094**	**18.058**	**19.731**
4	Income Tax Recovery	(0.150)	(0.243)	(2.080)	(2.473)
5	**Subtotal w/ Income Tax Recovery**	**0.429**	**0.851**	**15.978**	**17.258**
6	Cost Capitalized (incl. AFUDC)	-	-	(18.507)	(18.507)
7	**Total Deferral Costs**	**0.429**	**0.851**	**(2.529)**	**(1.249)**

On pages 9 and 10 of the Supplementary Filing, FEI states:

> The OCU Project updated cost estimate, reflected in the table above, is based on the following:
>
> - […] An updated estimate of $0.555 million for the regulatory review of the proceeding from 2018 to 2023, including actual spending of approximately $0.235 million up to March 2023, recorded in the proposed OCU Application and Preliminary Stage Development Costs Deferral Account […]

On page 96 of the Updated Application, FEI states:

> FEI is seeking BCUC approval under Sections 59-61 of the UCA for deferral treatment of the Application and Preliminary Stage Development costs. […] FEI is seeking approval to record these costs in a new non-rate base deferral account, the OCU Application and Preliminary Stage Development Costs Deferral Account, attracting FEI's after tax weighted average cost of capital until it enters rate base. FEI proposes to transfer the balance in the deferral account to rate base on January 1, 2022 and commence amortization over a three-year period.

In response to BCUC IR 33.1, FEI provided a breakdown by activity of the initial estimate of Application costs to be incurred (i.e. $0.400 million).

18.1 In a format similar to that provided in response to BCUC IR 33.1, please provide a breakdown by activity of the updated estimate for Application costs (i.e. $0.555 million). As part of the response, please explain the nature of the balance of Application costs yet to be incurred (i.e. $0.320 million).

Response:

Please refer to Table 1 below for the breakdown of the Application costs, forecast to be $0.555 million as part of the Supplementary Filing, by activity in a similar format as provided in the response to BCUC IR1 33.1.

While responding to this IR, FEI discovered a typographical error on page 10 of the Supplementary Filing; the actual spending up to March 31, 2023 should have been $0.239 million, not $0.235 million. This typographical error has no impact on the total Project costs presented in Table 3-1 of the Supplementary Filing or the financial analysis presented in Table 4-1 of the Supplementary Filing. The total forecast Application costs, including actuals up to March 31, 2023, remain at $0.555 million.

As shown in Table 1 below, the balance of the $0.316 million (forecast Application costs to the end of 2023) includes BCUC costs, intervener costs, and expenses for external legal counsel. These forecasts are based on the following:

- For the BCUC costs and expenses for FEI's external legal counsel, the forecasts to the end of 2023 are based on the remaining regulatory process expected to the end of 2023, which includes one round of IRs (i.e., IRs on the Supplementary Filing) and written final and reply arguments.
- For the intervener costs:
    - The actual amounts in 2021 and 2022 are the interim Participant Cost Awards (PCA) that were approved for BCSEA and RCIA by Orders F-15-22 and F-18-22, respectively.
    - The 2023F amounts include forecast PCA for BCSEA and RCIA for the remaining regulatory process not included in the interim PCA, and the forecast PCA for the other interveners for the entire regulatory process.

Table 1: Breakdown of OCU Application Costs by Activity

Particulars	CPCN Application Costs $000's					
	2020A	2021A	2022A	2023A	2023F	Total
BCUC	$ -	$ -	$ 4	$ -	$ 31	$ 35
Intervenor	-	5	72	-	213	290
Legal	44	100	3	-	73	220
Expert / Consultant	-	-	-	-	-	-
Notice / Publication	-	10	-	-	-	10
Administrative	-	-	-	-	-	-
Total	$ 44	$ 115	$ 80	$ -	$ 316	$ 555

F. ENVIRONMENT AND ARCHEOLOGY

19.0 Reference: PROJECT COST AND SCHEDULE

Exhibit B-35, Table 3-2, p. 11, pp. 17-18; Exhibit B-2, BCUC IRs 36.1, 38.1; Exhibit B-14, BCUC IR 58.1

Permitting and Agreements

FEI indicates in Table 3-2 of the Supplementary Filing that permitting for the OCU Project is generally expected to occur between January 2024 and January 2025, including permits from the Department of Fisheries and Oceans (DFO), Ministry of Transportation and Infrastructure (MoTI), Municipal, BC Energy Regulator (BCER), and Environmental and Archeological permits.

FEI stated in BCUC 36.1 that the gas line design for the OCU Project does not meet some of the criteria specified within the MoTI Utility Policy Manual and that FEI expected a response from the MoTI on the need for variances and FEI's variance application in March 2021. According to BCIC IR 58.1, FEI was still awaiting a response in May 2021.

19.1 Please provide an update on discussions with the MoTI regarding alignment of the gas line design for the OCU Project with the MoTI requirements.

Response:

FEI submitted a request to MoTI for four variances from the requirements set out in the Ministry of Transportation and Infrastructure Utility Policy Manual for the design and construction of the OCU Project as follows:

- UPM Clause 17.3.3(a) – approximately 550 metres of the proposed alignment falls inside, or within 30 metres of and parallel to MoTI's Saliken Drive Right of Way (ROW), near the City of Penticton;
- UPM Clause 17.4.1(e) – the crossing of Saliken Drive is proposed to be completed by an uncased open trenching method;
- UPM Clause 17.4.1(b) – the crossing of Chute Lake Road is currently designed to cross the ROW at an angle less than 70°; and
- UPM Clause 17.4.1.(e) – the crossing of Chute Lake Road is proposed to be completed by an uncased open trenching method.

FEI's request for the four variances described above was accepted by the MoTI Chief Engineer in June of 2021 with no other conditions.

19.2 Please provide an update on any communications with DFO related to a request for review or permitting of the project.

Response:

FEI has paused environmental permitting work while it seeks consent from Indigenous groups for the Project; therefore, there have been no communications with the DFO since the initiation of the CPCN process. There is sufficient time in the current OCU Project schedule to complete DFO permitting requirements prior to the proposed construction start.

19.3 Please provide any available updates on the status of the Environmental management plan, and any engagements with BCER which may have a bearing on the project.

Response:

FEI has paused work on the Environmental Management Plan (EMP) and engagement with the BCER while it seeks consent from Indigenous groups for the Project. There is sufficient time in the current OCU Project schedule to complete the EMP prior to submission of permit application(s) with the BCER.

FEI confirmed in BCUC 37.1 that with respect to the one high risk APEC (area of potential environment concern) identified in the study area, namely the active Campbell landfill, FEI was working with the Campbell Mountain Landfill operator's preferred environmental consultant, Sperling Hansen, to better understand the environmental implications of constructing a gas line through a short section of the landfill.

On pages 17 to 18 of the Supplementary Filing, FEI states:

> Bi-weekly meetings were held with [City of] Penticton to provide project updates, seek feedback on the project, and create a Terms of Reference Agreement (TOR). The TOR outlines: the three parcels of Penticton-owned land for which the OCU Project requires Surface-Rights-of-Way, and timelines for project-related permit reviews and approvals from Penticton. Feedback was received from Penticton on

the TOR, and FEI plans to send a final draft to send back to Penticton before the end of May for signing.

On page 18 of the Supplementary Filing, FEI states:

> FEI plans to send a final draft of the Landfill Agreement to the RDOS [Regional District of Okanagan-Similkameen] for signing before the end….
>
> On June 2, 2022, FEI appeared as a delegation and presented updates to the RDOS Board of Directors regarding the OCU Project, including information on the route, community and Indigenous relations, environmental impacts and mitigations, and other general OCU Project updates.
>
> … On April 17, 2023, FEI had a meeting with Penticton to provide an update on the progress of the OCU Project and notified them of the status of the agreements. FEI will be commencing the meetings in May 2023, to finalize negotiations on the agreements and have both parties sign the agreements.

19.4 Please provide an update on the status of the agreements with Penticton and the RDOS, including any impacts on cost and timing.

Response:

On May 4, 2023, FEI provided the City of Penticton an update on the OCU Project and sent the finalized Terms of Reference document and Campbell Mountain Landfill Agreement. The City of Penticton reviewed both documents and sent FEI its comments. On June 7, 2023, FEI sent a revised Terms of Reference document and Campbell Mountain Landfill Agreement. The agreements are currently with the City of Penticton awaiting review and confirmation.

Associated cost or timing implications have been incorporated into the OCU Project estimates.

G. CONSULTATION

20.0 Reference: PROJECT COST AND SCHEDULE

Exhibit B-35, Table 3-2, p. 11; Exhibit B-22, BCUC 69.1 Land Acquisition

FEI provides the following information regarding land acquisition of page 11 of the Supplementary Filing:

Detailed Engineering Design and Land Acquisition	
Engineering Detailed Design	Jan 2024 – Sept 2024
Preliminary Land Negotiation - Option to Purchase	Complete
Land Acquisition	Oct 2023 – Dec 2023

FEI stated in response to BCUC 69.1 that it had acquired [redacted] out of 40 of the Statutory Right of Ways (SRWs) required to construct the OCU Project. Some acquisitions remained outstanding, and FEI expected to acquire these SRWs in the near future; however FEI was considering final options for acquiring an SRW on those properties, including expropriation if necessary.

20.1 Please provide an update (confidentially if necessary) on progress with respect to landowner negotiations, including the impact on project timing and budget.

Response:

With the exception of one property which FEI has purchased (due to landowner preference), FEI has successfully negotiated Agreements to Grant SRWs with all landowners directly along the OCU Project route; no properties were expropriated. These agreements involve two steps: the first step is a non-refundable deposit paid to the landowners when signing the agreement; the second step is the payment of the remainder of the agreed compensation to the landowners upon BCUC approval of the OCU Project, prior to December 31, 2023. If BCUC approval is not obtained by the December 31, 2023 deadline, the agreements will automatically terminate unless FEI succeeds in negotiating amendments with the landowners.

If FEI is successful in negotiating amendments to the agreements by the December 31, 2023 deadline, there will be no expected impact on the OCU Project schedule. If FEI is not successful in negotiating amendments to the agreements and FEI does not receive BCUC approval of the OCU Project by the December 31, 2023 deadline, this may impact project timing. FEI will need to negotiate new SRW acquisition agreements with the landowners and explore expropriation in the event FEI is unable to reach agreement with the landowners. With either approach, FEI estimates an increase in SRW compensation payments of between 20 percent and 40 percent due to increases in land values since the agreements were signed in 2020/21.

21.0 Reference: LOCAL GOVERNMENT AND STAKEHOLDERS

Exhibit B-35, Section 5, pp. 17-18; BCUC CPCN Guidelines, p. 6
Public Consultation

On page 17 of the Supplementary Filing, FEI states:

> Bi-weekly meetings were held with Penticton to provide project updates, seek feedback on the project, and create a Terms of Reference Agreement (TOR). …

On page 18 of the Supplementary Filing, FEI states:

> On June 2, 2022, FEI appeared as a delegation and presented updates to the RDOS [Regional District Okanagan Similkameen] Board of Directors regarding the OCU Project, including information on the route, community and Indigenous relations, environmental impacts and mitigations, and other general OCU Project updates.

First Things First Okanagan presented to the RDOS Environment and Infrastructure Committee on April 21, 2022, requesting RDOS support in opposing the OCU Project Application https://pub- rdos.escribemeetings.com/FileStream.ashx?DocumentId=4682

FEI states on page 17 that it made a virtual presentation to an interested community member group, First Things First Okanagan, on the OCU Project and the benefits of the Diversified Pathway on 29 April 2022.

Page 6 of the CPCN Guidelines includes the following information requirements for public consultation:

(iii) Description of the issues and concerns raised during consultations, the measures taken or planned to address issues or concerns, or an explanation of why no further action is required to address an issue or concern.

(iv) Identification of any outstanding issues or concerns.

21.1 Please describe any issues or concerns raised by either the City of Penticton or the RDOS regarding the OCU project, and the measures FEI has taken to address these concerns.

Response:

FEI has been in discussion with the City of Penticton and the RDOS and the few concerns raised in these meetings were addressed in the proposed Terms of Reference and Campbell Mountain Landfill Agreement.

The City of Penticton raised concerns about communication and ensuring that any concerns raised by landowners and/or the community would be sent directly to FEI. To address this concern, FEI set up a dedicated project website, email address and phone line. FEI also directly contacted landowners along the route and has worked in collaboration with the City of Penticton to address concerns.

The RDOS made FEI aware of a permanent, provincially mandated bear fence that runs through the operational area. FEI is working with the RDOS to ensure that during construction a gated temporary bear fence to the specifications of the RDOS is erected and maintained. The RDOS raised concerns of construction impacting the landfill and FEI has committed that it will not unreasonably interfere with the landfill facility's operations, or with public access to the landfill facility, during its operational hours. FEI will not unreasonably disrupt or impede traffic on Reservoir Road during the operational hours of the landfill facility. The RDOS also raised concerns in relation to the storm drainage channels and FEI is working with the RDOS to identify the locations of these channels to ensure it does not impede the natural storm drainage channel.

21.1.1 Please discuss any feedback FEI has received to date from Penticton or RDOS municipalities in the Okanagan regarding alignment with local government planning including but not limited to the Penticton Community Climate Action Plan.

Response:

FEI has taken into consideration the Penticton Community Climate Action Plan and is currently in conversation with the RDOS about the feasibility of connecting the landfill to the gas system and exploring renewable gas opportunities.

21.2 Please identify any outstanding issues or concerns raised in the public consultation process.

Response:

During the public consultation process, FEI heard concerns regarding invasive species and GHG emissions from the Okanagan and Similkameen Invasive Species Society (OASSIS) and First Things First Okanagan (FTFO), respectively.

FEI met with OASSIS to discuss the OCU Project and learn about the work OASSIS is doing with invasive species in the area. To mitigate any impacts to the work OASSIS is doing, FEI added OASSIS to the OCU Project stakeholder list so it would receive notifications about OCU Project updates. FEI plans to continue to work with OASSIS as requested.

FTFO raised several concerns regarding GHG emissions. FEI answered specific questions relating to the OCU Project, explained FEI's climate plan, including its general vision for decarbonizing the gas system. FEI will continue to share information with FTFO as requested.

FEI also met with landowners along the route and will continue to work in collaboration to address concerns if they arise. FEI has a dedicated webpage, email, and phone line available to the public to share any issues or concerns.

22.0 Reference: CONSULTATION AND ENGAGEMENT

Exhibit B-35, Section 5.2.3, p. 19, Appendix D, p. 52; BCUC CPCN Guidelines, pp. 5-6 Adequacy of Consultation

On page 19 of the Supplementary Filing, FEI states:

> The BCUC regulatory process was adjourned on February 23, 2022. Following the adjournment, PIB and FEI continued discussions regarding the OCU Project. On March 31, 2023, FEI advised the BCUC that discussions between PIB and FEI were progressing well. FEI remains optimistic and anticipates advising the BCUC whether FEI and the PIB can reach an agreement with respect to the OCU Project in the coming months. FEI is seeking PIB's consent for the OCU Project in that agreement.

The updated consultation log in Appendix D adds one entry for "2021 – present" stating "PIB discussions took place on a confidential basis and are not detailed for that reason."

The BCUC CPCN Guidelines state on pages 5-6:

> For each potentially affected First Nation, summarize the consultation to date, including:
>
> …
>
> (iii) A chronology of meetings, other communications and actions.
>
> (iv) Any relevant, non-confidential written documentation regarding consultation, such as notes or minutes of meetings or phone calls, or letters received from or sent to the First Nation.
>
> (v) Identification of specific issues or concerns raised by the First Nation.
>
> (vi) Description of how the specific issues or concerns raised by the First Nation were avoided, mitigated or otherwise accommodated, or explain why no further action is required to address an issue or concern.

22.1 Please provide an update of all meetings, other communications and actions with the PIB from April 2021 to the present. Any notes or other confidential information may be redacted and provided confidentially, as required.

Response:

This response is being provided on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-72-23. The confidential information is commercially sensitive information that cannot be disclosed under the terms of an agreement between FEI and the PIB with respect to their negotiations. Further,

the confidential information should remain confidential in perpetuity as disclosure may harm or prejudice negotiations with other parties in the future. The confidential response will be filed with the BCUC under separate cover and will be made available to registered parties with signed Confidentiality Declarations and Undertakings filed on the record in this proceeding.

[redacted]

1

22.2 Please provide an update, confidentially if necessary, on the latest issues and concerns raised by the PIB and the actions taken by FEI to address them, or explain why no further action is required.

Response:

This response is being provided on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-72-23. The confidential information is commercially sensitive information that cannot be disclosed under the terms of an agreement between FEI and the PIB with respect to their negotiations. Further, the confidential information should remain confidential in perpetuity as disclosure may harm or prejudice negotiations with other parties in the future. The confidential response will be filed with the BCUC under separate cover and will be made available to registered parties with signed Confidentiality Declarations and Undertakings filed on the record in this proceeding.

[redacted]

H. PROVINCIAL GOVERNMENT ENERGY OBJECTIVES

23.0 Reference: PROVINCIAL GOVERNMENT ENERGY OBJECTIVES AND POLICY OBJECTIVES

Exhibit B-35, Section 6, pp. 20-21; FEI 2022 Long-Term Gas Resource Plan Proceeding, Exhibit B-23, BCUC IRs 82.3, 121.1

OCU Project Alignment with BC Energy Objectives

On page 20 of the Supplementary Filing, FEI states:

> The OCU Project is aligned with CleanBC as it supports FEIs transition to low-carbon gases and investment in energy efficiency to reduce consumption.

23.1 Please explain how the OCU Project specifically supports the transition to low-carbon gases and investment in energy efficiency, providing examples of each.

Response:

The OCU Project is consistent with transitioning to a low carbon future where the gas system may supply less energy but supply similar levels of peak capacity. FEI considers that the gas and electric systems need to have an integrated approach to decarbonize the building and industrial sector, including the transition to low carbon gases and the investment in energy efficiency to reduce consumption. With an integrated approach, the gas system (including low-carbon gases) can serve much of the peak capacity requirements for space heating, water heating, and industrial loads, with a share of the annual energy demand requirement being provided by the electric system.

An example of how the OCU Project specifically supports the investment and transition to low-carbon gases is discussed in the response to BCSEA Supplementary IR1 36.1. The response outlines how the CleanBC Roadmap to 2030 describes the important role of BC's gas infrastructure as a means to enable the transition to renewable and low carbon gases in support of the Province's climate and economic objectives.

An example of energy efficiency would be a FortisBC customer replacing a gas furnace with a dual fuel hybrid system. In this example, the energy required for heating in the shoulder seasons would be supplied by an electric heat pump (when the heat pump efficiency is greatest) with the gas furnace providing energy for heating during the cold seasons (when the heat pump efficiency is lowest, and its capacity impacts to the electrical grid are the highest). The capacity of the gas system needed to accommodate this dual fuel integration is similar to the capacity needed by customers using gas-only equipment; however, the associated GHG emissions would be reduced by shifting shoulder season demand to the electric system via an electric heat pump.

The key driver of the OCU Project is to meet increasing peak load demands in the Southern Interior primarily driven by population growth. The peak load demands will likely persist regardless

of whether customers remain on conventional gas equipment or retrofit to dual-fuel heating systems.

FEI states on page 21 that despite the impact of efficiency measures to reduce energy use per customer over time, potential capacity expansions are nonetheless required to meet growing peak loads with increasing proportions of renewable and low carbon gas supply.

23.2 Please provide a graph comparing the projected load in the study area, before and after forecast DSM, and include a description of the types of DSM measures included in the analysis.

Response:

FEI's estimates of future DSM energy savings were undertaken on a broader regional basis and are not available at a degree of geographic granularity that enables this analysis to be undertaken for just the area served by the OCU Project. Please refer to the response to BCUC Supplementary IR1 3.9.1 for an estimate of pre- and post-DSM energy demand for the Southern Interior, which is the most granular level of detail available for this information.

FEI states on page 20 that the OCU Project is needed to support peak energy demand in the Okanagan, "a critical service which is difficult to electrify", and cites the evidence filed in the LTGRP on the impacts to the electric system associated with electrifying gas heating load in Kelowna.[19] FEI states the study demonstrates that the additional peak demand and land required for electrification indicates additional electric infrastructure "may not be an optimal approach to decarbonization."

In Exhibit B-23 of the 2022 Long-Term Gas Resource Plan proceeding, FEI stated in response to BCUC IR 82.3, that FEI is evaluating concepts of hybrid systems through further activity related to the Kelowna Electrification Case Study:

> Further capacity modeling and analysis is needed to understand the impact of hybrid systems on both the gas and electricity systems and the value of avoided capacity compared to other resource options. This could facilitate a better understanding of quantifying the value of the gas peaking service and mitigating the potential increase in gas rates resulting from decreased gas load.

[19] FEI 2022 Long-term Gas Resource Plan Proceeding, Exhibit B-20, Kelowna Electrification Case Study.

FEI stated in response to BCUC 121.1 that it expects that further studies related to the Kelowna Electrification Case Study will evolve as FEI and FBC together examine the potential for greater integration between the two energy systems and learn more through the implementation of more integrated solutions. For this reason, FEI cannot state the full extent of possible future studies. At this time, however, FEI and FBC envision the following high-level activities:

- Extending the examination of system integration potential to all of the FEI/FBC shared service territory;
- Examining the potential for optimizing the use of both gas and electricity systems to cost- effectively decarbonize energy use and enhance energy delivery resiliency through equipment (such as hybrid heating systems) and service offerings that can enable peak load shifting;
- Examining the potential to optimize the use and allocation of renewable and low carbon gases as well as clean and renewable electricity, and decrease the reliance on conventional sources of natural gas over time;
- Studying, developing and, where appropriate, implementing behavioral and/or equipment- based rebate programs and service offerings that increase the value of system integration to customers; and
- Examining the potential for and implications of incorporating supply resources for renewable and low-carbon gas as well as clean and renewable electricity within the shared services territory as well as within BC but outside the shared services territory.

23.3 Please discuss to what extent FEI has explored the impact on peak loads of shifting to a dual- energy system in the ITS, for example, electrifying base-load heating, and using gas backup to relieve pressure on electrical systems at peak times.

Response:

At this time, FEI has not yet fully explored the impact on peak loads of shifting gas heating beyond the initial analysis conducted for the Kelowna Electrification Case Study, which is for a “full” shift of gas to electric load. FEI is currently examining the use of hybrid heating (or dual-fuel energy) systems to further explore the impact and benefits of a hybrid approach to gas and electric deliveries. All else equal, hybrid systems would not be expected to increase gas peak demand as the requirement during the winter months would be similar whether it is using gas for heating with a hybrid system or with a gas-only system.

23.4 Please discuss the extent to which FEI considers the scope and results of the Kelowna study are applicable to the OCU Project.

Response:

FEI considers that generally the findings of the Kelowna Electrification Case Study can be extended to the broader area applicable to the OCU Project. The study illustrates that even a moderate shifting of gas to electric load within the City of Kelowna would result in significant infrastructure and land expenditures for electric infrastructure required to meet the growing electricity demand.

23.5 Please provide FEI's views on postponing the OCU project until FBC and FEI have been able to explore the potential for optimizing the use of both gas and electricity systems and verify the need for the OCU Project.

Response:

FEI considers that while further integrating the gas and electric systems in the FEI/FBC shared service territory over time will potentially have system benefits and may add value for customers, it will not result in avoiding the capacity constraint that the OCU Project addresses.

First, the OCU Project is needed imminently, and the exploration of the potential for gas and electric system integration will not be completed in time nor is it expected to result in any meaningful avoidance of gas peak demand growth.

Second, while integrating use of the gas and electric systems could result in a reduction in *annual* gas demand, there would be continued reliance on the gas system to meet overall *peak* energy needs, which is the driver of the OCU Project.

Third, if the OCU Project is not placed into service within its proposed timeline, FEI would likely be unable to connect any new gas customers to meet growth in the region.

Therefore, postponing the OCU Project any further puts energy consumers in the region at greater risk of potential outages at times of the greatest need for gas service (during extreme cold weather events).

Attachment 1.7

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 17.1

Contact

josephrs1@gmail.com

www.linkedin.com/in/joseph-r-sukhnandan (LinkedIn)

Top Skills

Engineering Management
Project Management
Project Planning

Certifications

Professional Engineer (P.Eng.)
Professional Certification Engineering Management (PCEM)
Project Risk Management Professional (PRMP)
Project Management Professional (PMP)
PMI Scheduling Professional (PMI-SP)

Joseph Sukhnandan

Project Director
United States

Summary

Thirty-six years progressive engineering and project management experience in Canada, Belize and USA. Twelve years senior leadership and oversight roles at the Belize electric utility. Eight years senior management and project director role at a Canadian electric/gas utility.

Experience

Sukhnandan Consulting LLC
Manager/Principal
January 2017 - Present (6 years)
USA

Advised on project feasibility reviews, alternative project delivery methods, open book cost estimating and schedule reviews, risk management and risk quantification. Advised on the development of two renewable energy projects.

FortisBC
Sr. Project Director
June 2018 - December 2022 (4 years 7 months)
Canada

Directed the Major Projects project management office functions. Managed key aspects of project development and collaborated on regulatory applications for five multi-hundred million dollars pipeline projects. Directed development of governance and assurance, phase gate, risk management, project controls and project delivery processes. Spearheaded development of processes for planning, breakdown structures, scheduling, cost estimating, risk quantification and reporting.

FortisBC
Chief Engineer/part Sr PM
August 2012 - December 2016 (4 years 5 months)
Canada

Managed the department’s engineering functions and the annual sustaining capital program. Collaborated on two regulatory applications. Project manager for a large-scale hydroelectric storage facility.

Belize Electric Company Limited

Manager, Engineering

June 2011 - July 2012 (1 year 2 months)

Belize

Technical analysis for planned acquisition of electric utility assets in the USA. Managed performance testing and commissioning of a hydroelectric facility.

Belize Electricity Limited

24 years 10 months

Vice President, Engineering & Energy Supply / Projects & Generation

October 2000 - June 2011 (10 years 9 months)

Belize

Directed engineering and operational aspects for all technical departments. Directed technical interconnection, contract negotiations and regulatory applications and approvals for three independent power producers. Owner’s representative/Project Director role for the construction of two hydroelectric facilities and interconnection to utility grid, design and construction for a 69 kV transmission line and substations, substation upgrades and construction of three substations to interconnect independent power producers (project development/feasibility to commissioning and handover for all projects).

Manager/Project Manager/Engineer

September 1986 - October 2000 (14 years 2 months)

Belize

Various technical, engineering and department managerial roles. Various project/construction management and engineering roles for one hydroelectric project, electric transmission, distribution and substation projects.

Education

University of Cambridge

BA (Hons), Engineering · (October 1983 - June 1986)

The George Washington University

MSc, Electrical Engineering · (August 1993 - January 1995)

Penn State University

Graduate Program, Advanced School in Power System Engineering · (August 1989 - December 1989)