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December 23, 2021

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Inc. (FBC)

2021 Long-Term Electric Resource Plan (LTERP) and Long-Term Demand-Side Management Plan (LT DSM Plan) (Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On August 4, 2021, FBC filed the Application referenced above. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-314-21 for the review of the Application, FBC respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

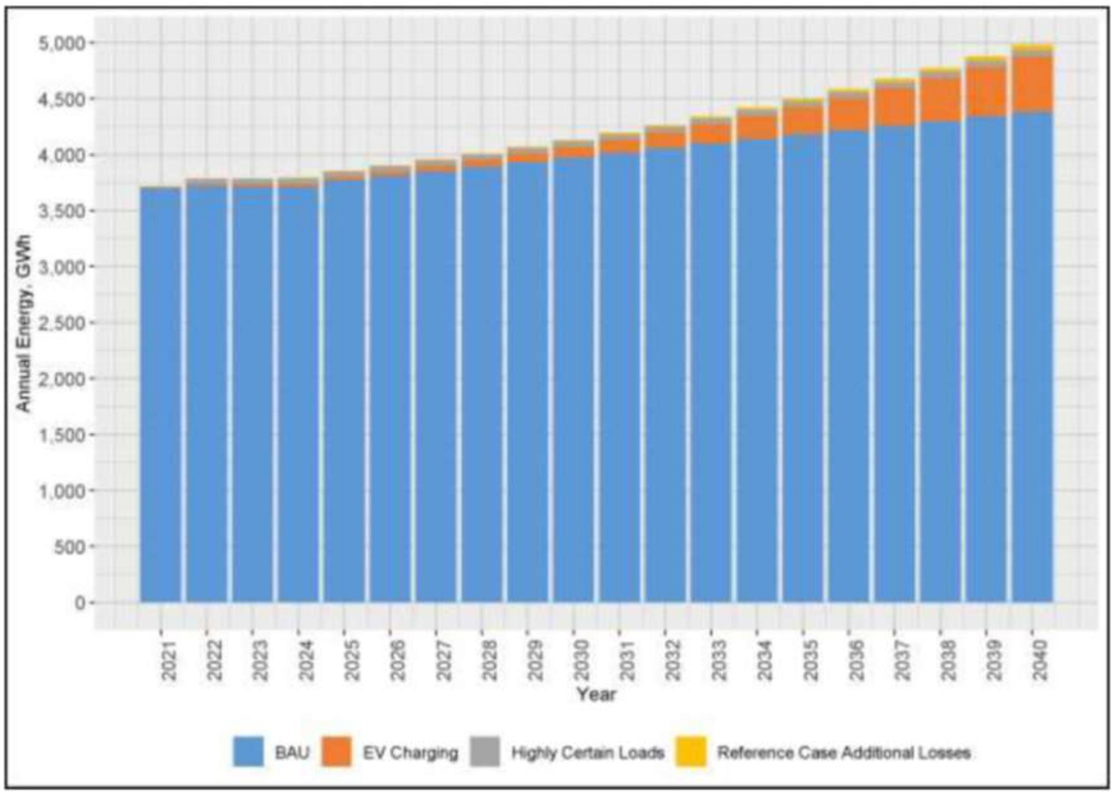
Attachments

cc (email only): Commission Secretary
Registered Parties

1 EXECUTIVE SUMMARY

1. Reference: Exhibit B-1, Page ES5

Figure ES-1: Gross Energy Load Forecast (GWh)



1.1 Please provide the expected introduction of net metering solar energy reduction of loads expected over the same time period, including the potential for solar-based charging for vehicles as the cost of solar energy capture and use becomes increasingly competitive between now and 2040, and provide FBC's assumptions with respect to solar displacement of loads and load growth.

<u>Response:</u>

FBC has not assumed any material incremental energy reduction of loads due to net metering solar energy or the potential for solar-based charging for vehicles in its BAU or Reference Case load forecast. As discussed in Section 2.3.4, the estimated annual energy generation is currently about 6 GWh per year, or less than 0.2 percent of FBC's total annual energy requirement in 2020. This current level of generation is already captured in the BAU and Reference Case load forecasts as it is intrinsic in the historical load data.

FBC's load scenarios include greater amounts of solar energy load reduction beyond the BAU and Reference Case load forecasts. As discussed in Section 3.3 of Appendix H – Load Scenarios Assessment Report, three of the load scenarios include varying levels of energy load reduction due to net metering solar PV paired with battery storage, although FBC did not specifically include any impacts of solar-based charging for vehicles within its load scenarios. The energy reductions by 2040 are as follows:

- Scenario 2 (Lower Bound)
  - Residential energy load reduction: 333 GWh
  - Commercial energy load reduction: 49 GWh
- Scenario 3 (Deep Electrification)
  - Residential energy load reduction: 151 GWh
  - Commercial energy load reduction: 25 GWh
- Scenario 5 (Distributed Energy Future)
  - Residential energy load reduction: 252 GWh
  - Commercial energy load reduction: 33 GWh

1.2 Please confirm that the FBC gross load growth for the last 10 years will go from an average of .24% growth per year to a forecast load growth for BAU of .93% gross load growth and Reference Case gross load growth of 1.18% per year over 20 years (not compounded annual rates but average growth from the 2021 base to 2040).

Response:

Not confirmed. The average annual gross load growth rate for the last 10 years was 0.54 percent per year. The average annual gross load growth rate for the BAU is forecast to be 0.90 percent per year. The average annual gross load growth rate for the Reference Case is forecast to be 1.56 percent per year.

The tables below show both the historical, BAU and Reference Case load forecast growth rates.

Historical Gross Load Growth Rates from 2011 to 2020

	Historical Normalized Actuals	
Year	**Gross Load (MWh)**	**Annual Growth (%)**
2011	3,447,280	
2012	3,421,657	-0.74%
2013	3,499,975	2.29%
2014	3,433,082	-1.91%
2015	3,446,152	0.38%
2016	3,480,297	0.99%
2017	3,511,820	0.91%
2018	3,563,824	1.48%
2019	3,592,459	0.80%
2020	3,615,884	0.65%
Average		0.54%

BAU and Reference Case Gross Load Growth Rates from 2021 to 2040

	BAU Forecast		Reference Case Forecast	
Year	**Gross Load (MWh)**	**Annual Growth (%)**	**Gross Load (MWh)**	**Annual Growth (%)**
2021F	3,697,614		3,717,367	
2022F	3,723,006	0.69%	3,787,675	1.89%
2023F	3,716,215	-0.18%	3,786,862	-0.02%
2024F	3,715,558	-0.02%	3,793,785	0.18%
2025F	3,769,987	1.46%	3,854,576	1.60%
2026F	3,810,545	1.08%	3,903,924	1.28%
2027F	3,851,957	1.09%	3,956,758	1.35%
2028F	3,893,210	1.07%	4,012,077	1.40%
2029F	3,934,207	1.05%	4,069,818	1.44%
2030F	3,975,121	1.04%	4,130,195	1.48%
2031F	4,016,586	1.04%	4,195,858	1.59%
2032F	4,057,966	1.03%	4,266,270	1.68%
2033F	4,098,465	1.00%	4,340,736	1.75%
2034F	4,138,317	0.97%	4,419,554	1.82%
2035F	4,178,554	0.97%	4,500,776	1.84%
2036F	4,218,349	0.95%	4,586,294	1.90%
2037F	4,258,493	0.95%	4,676,998	1.98%
2038F	4,299,718	0.97%	4,773,699	2.07%
2039F	4,341,018	0.96%	4,875,420	2.13%
2040F	4,383,318	0.97%	4,983,177	2.21%
Average		0.90%		1.56%

1.3 Please confirm that the Business As Usual (“BAU”) representation is not business as usual for the last 10 years, which has been substantially lower than the prior 10-year average.

Response:

FBC interprets this question as asking if the 2021 LTERP BAU forecast average annual growth rate is higher than the ten-year historical average annual growth rate.

FBC confirms that the average annual growth rate for the BAU forecast is 0.36 percent higher than the historical average annual growth rate when considering ten years of historical data.

The "BAU" forecast is "business as usual" because it uses the same methods as all of FBC's recent load forecasts and is based on actual historical data. As described in Appendix F, the BAU methods are rate-specific and more complex than a simple 10-year average aggregate load growth forecast. Based on historical data, the methods pick up trends and changes that may be occurring in each rate class. Changes in the historical data include, but are likely not limited to:

- New large industrial loads from the cannabis and data mining sectors that did not exist ten years ago;
- Intrinsic EV charging, distinct from the *ZEV Act* mandate targets included in the Reference Case load forecast;
- Changes to the supporting forecasts FBC relies on such as the CBOC GDP forecast used in the commercial load method;
- Changes to residential use rates from increased efficiencies from new technology such as LED lighting, as well as new battery charging loads that were not as prevalent in the past;
- Changes in migration and housing types in the service territory. Changes in the housing markets impact migration rates while changes in housing types from single family dwellings to multi-family impact use rates;
- Changes to the results of the industrial survey for individual customers that may be experiencing more demand for their products; and
- Changes to wholesale loads as our wholesale customers grow at different rates.

A forecast that simply maintained the average annual growth rate of 0.54 percent would not properly account for the drivers listed above and would not be reasonable.

1.4 Please provide FBC's analysis of why the last 10 years has been relatively flat in terms of load growth.

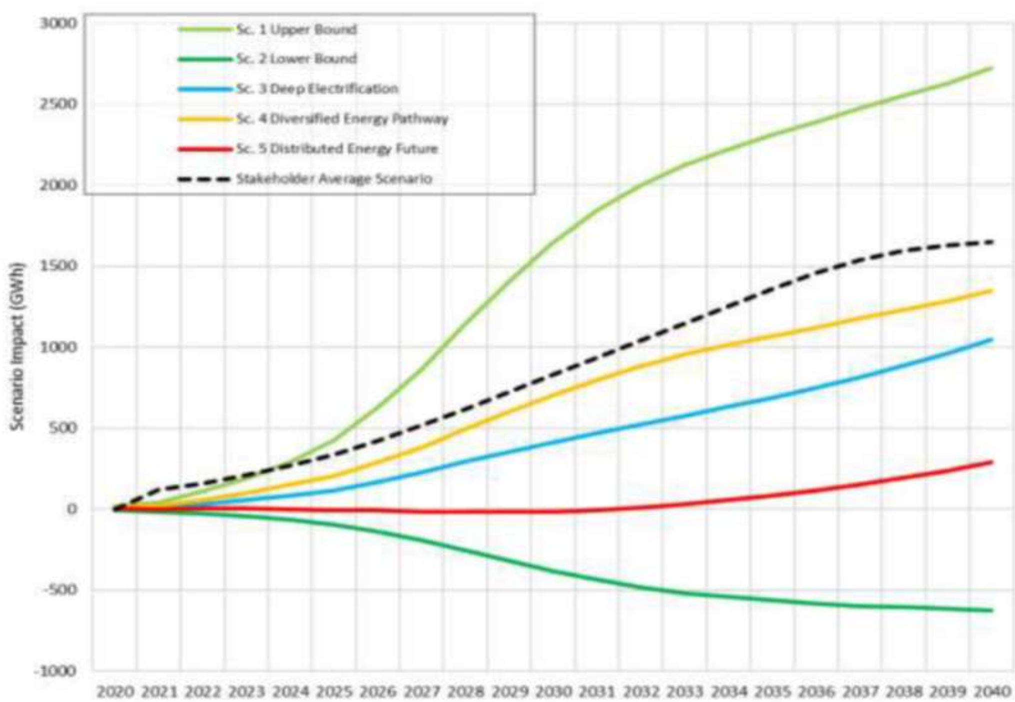
Response:

FBC's average annual growth rate of 0.54 percent over the past 10 years has been primarily due to the residential, commercial, wholesale and industrial classes experiencing relatively small changes to average annual load of 4 GWh, 12 GWh, -1 GWh, and 11 GWh, respectively. Data for the years 2013 and 2014 was not included in these annual average growth values since the integration of the City of Kelowna system and customers in 2013 would skew the data. FBC is unable to pinpoint the exact reasons for the increases or decreases in the residential, commercial, wholesale, industrial, irrigation, and lighting loads in any year.

2. Reference: Exhibit B-1, Page ES7 & Page ES8

> As part of its long-term resource planning, FBC explores alternate load scenarios to the Reference Case load forecast. In this LTERP, FBC explored two boundary scenarios and three intermediate scenarios as well as stakeholder scenarios. Load driver penetrations in the boundary scenarios help FBC understand the potential impact that each of these load drivers could have under extreme, but plausible, penetration scenarios, providing upper and lower limits for the other intermediate scenarios. The intermediate scenarios, which include combinations of load drivers that increase and decrease load, may be more reasonable potential future pathways. However, at this point in time, there is too much uncertainty to know which of the scenarios, if any, will occur in the future.

Figure ES-4: Load Scenarios' Annual Energy Impacts



2.1 Please provide FBC's probability estimate for: (a) a Distributed Energy Future; (b) a Diversified Energy Pathway; and (c) a Deep Electrification future.

<u>Response:</u>

As cited in the preamble, at this point in time, there is too much uncertainty to know which of the scenarios, if any, will occur in the future. Therefore, FBC is unable to assign any probability estimates to the load scenarios.

2.2 Please confirm that the probabilities for these other future paths must be low for FBC to have adopted a Reference Case forecast as high as the one in figure ES-1.

Response:

As discussed in the response to CEC IR1 2.1, FBC has no probability estimates for the load scenarios. At this time, FBC does have more certainty in the Reference Case load forecast as it is based on the intrinsic historical load drivers in the BAU forecast plus EV charging impacts based on the legislated *ZEV Act* sales targets and highly certain large loads.

3. Reference: Exhibit B-1, Page ES11

Table ES-1: Load-Resource Balance Gaps

	First Year of Gap	2040 Gap With PPA Renewal	2040 Gap Without PPA Renewal
Annual Energy (GWh)	2023	1,410	2,450
Winter Capacity (MW)	2028	245	445
Summer Capacity (MW)	2028	240	440
June Capacity (MW)	2021	280	480

3.1 Given the uncertainty of the gap for load resource balance with and without the PPA Renewal (1040 GWh), would it make more sense for FBC to negotiate a PPA agreement that has stage points for renewal of partial amounts so that at any given time the amounts expiring if realized would be manageable additions and so that market energy can provide flexibility?

Response:

There is no mechanism for a staged renewal of the current PPA, the terms of which are currently set, and do not expire until 2033. Upon renewal of the PPA Agreement, if FBC and BC Hydro should choose to renew, a staged renewal could be a topic of discussion. However, long-term contracts such as the PPA take many years to negotiate; as such, both parties desire a great amount of certainty in the final contract, thus making a staged renewal option less attractive. FBC plans to begin review of the PPA in 2023, 10 years prior to expiration, to determine if negotiations should begin with BC Hydro to renew the PPA.

Furthermore, FBC believes that there is sufficient flexibility under the contract as it is currently designed. It ensures access to a maximum of 200 MW of demand and 1,752 GWh of energy on an annual basis; however, there are provisions within the contract that allow FBC to shape and scale up or down its usage, along with corresponding costs, based on requirements. This flexibility provides access to firm power when required and the ability to mitigate power purchase expense when the market is favourable or when loads are lower than forecast. The PPA also acts as a price ceiling during times of sustained high market prices.

4. Reference: Exhibit B-1, Page ES12

Table ES-2: Key DSM Scenario Data

Category	DSM Scenario				
	Low	Base	Med	High	Max
Energy Savings, GWh					
Average per annum ('21 - '40)	21.0	21.8	22.4	23.4	25.2
Average per annum ('21 - '29)	26.8	28.0	29.4	31.4	34.5
Total (2021 to 2040)	421	435	449	468	503
Capacity Savings, MW					
Total (2021 to 2040)	61.6	64.0	65.6	68.1	72.7
Resource Cost, 2020 ($000s)					
Average Cost ($/MWh)	$38	$44	$49	$57	$75
Incremental cost compared to base case ($/MWh)	N/A	-	$183	$190	$234

4.1 Please provide the collective bill savings for participating customers as a % of their estimated bills over the total plan from 2021 to 2040.

<u>Response:</u>

The scope of the Conservation Potential Review did not specifically evaluate the impact of DSM programs on participant billing. There are a number of difficulties in determining an overall estimate of bill savings for participating customers, including the following:

- Billing rates and structure of rates vary significantly both between, and within, each customer segment;
- Bill savings are impacted by measure life that doesn't necessary persist through the plan period;
- Bill savings are impacted by interactive effects with other energy bills such as natural gas, propane, oil and wood;
- Some customer rates have a two-tiered structure for energy consumption (e.g., Rate 1 – Residential);
- Some customer rate classes have demand charges, while some do not (e.g., Rate 1 – Residential and Rate 30 – Small Commercial Service are not charged demand, whereas Rate 21 – Commercial Service is charged demand); and
- The market potential does not evaluate the extent of distribution of participation across the customer segment (e.g., one customer could participate in multiple DSM projects, while another may not participate in any DSM projects).

Notwithstanding these uncertainties, FBC provides below estimated percentages of the collective bill savings by customer type. These estimates are based on a high-level, simplistic analysis that reflects the following inputs: expected reduction in use by sector, percentage of bill reflecting energy savings, and estimated average participation rate for customers across each sector. Note that "participation rate" refers to the percentage of customers of a given sector that participate in any DSM program.

Residential

- The estimated average participation rate of customers in DSM programs over the plan is 35 percent.
- The estimated average collective bill savings for participating customers from 2021 to 2040 is 14 percent.

Commercial

- The estimated average participation rate of customers in DSM programs over the plan is 50 percent.
- The estimated average collective bill savings for participating customers from 2021 to 2040 is 15 percent.

Industrial

- The estimated average participation rate of customers in DSM programs over the plan is 66 percent.
- The estimated average collective bill savings for participating customers from 2021 to 2040 is 8 percent.

4.2 Please confirm that providing bill saving opportunities to customers is an important service metric for FBC and a significant contribution to overall affordability.

Response:

Confirmed.

4.3 Does FBC monitor bill savings and report these to the BCUC on a regular basis?

Response:

FBC does not monitor bill savings, nor report them to BCUC. However, FBC does conduct bill analysis for select customer participants in DSM programs as a part of the program evaluation process.

5. Reference: Exhibit B-1, Page ES16

> First, based on the Reference Case load forecast, FBC has no need for incremental generation resources until 2030. If FBC is able to shift some level of EV charging from peak periods, the need for new resources could be pushed out until at least 2031. Under higher load scenarios, FBC may need new resources as early as 2025.

> Fourth, clean or renewable resource portfolios that include gas plants using RNG fuel are more cost effective than portfolios that exclude gas plants. Battery storage and gas plants are the most optimal capacity resource in terms of cost and meeting LRB gaps.

5.1 Please provide the FBC assumption in the base Reference Case for EV charging during daily peak usage times versus assumed overnight charging and or battery stored energy charging.

<u>Response:</u>

Charging profiles for EVs, which determine the assumed share of daily charging activity happening in each hour, were derived from public sources, as well as FBC EV charger data. Citations for all the sources used may be found in Sections 2.3.1 and 2.3.2 of Appendix H – Load Scenarios Assessment Report. No assumptions were made regarding battery stored energy charging for EVs in the Reference Case load forecast.

5.2 Please provide the FBC assumption for EV charging rate incentive development for lower cost impact charging over the 2021 to 2040 period.

<u>Response:</u>

FBC's assumptions with respect to shifting of customer EV charging loads and incentive development include the following:

- Customers are generally expected to not be concerned about when EV charging begins, provided their vehicles are charged before they need them the next day;
- Whole-home TOU rates are not an optimal method for shifting EV loads due to anticipated lower efficacy and customer acceptance issues;
- FBC will be able to leverage both hardware and software-based approaches to control and/or validate the timing of customer EV loads; and
- A financial incentive with be provided to customers that do not charge during peak periods.

Please also refer to the responses to RCIA IR1 2.1, 2.2, and 33.1.

5.3 Please provide the cost assumptions for capacity FBC has used for battery storage from 2021 to 2040 and the estimates for clean peak capacity based on gas plants using RNG and or other renewable fuel options.

Response:

The following table shows the unit capacity cost (UCC) values from Table 10-2 of the Application for the three requested resources over the planning horizon (in 2020$ per kW-year).

Year	Battery Storage	Distributed Battery Storage	RNG SCGT
2020	267	226	131 to 148
2021	259	218	129 to 147
2022	251	211	129 to 147
2023	243	204	129 to 146
2024	235	196	130 to 147
2025	227	189	131 to 148
2026	223	185	131 to 148
2027	219	182	130 to 148
2028	215	178	130 to 148
2029	211	174	130 to 147
2030	207	171	129 to 147
2031	205	170	129 to 147
2032	204	168	130 to 148
2033	203	167	130 to 148
2034	202	166	130 to 148
2035	200	165	130 to 148
2036	199	164	131 to 148
2037	198	163	130 to 148
2038	196	161	130 to 148
2039	195	160	130 to 148
2040	194	159	131 to 148

1. INTRODUCTION

6. Reference: Exhibit B-1, Page 16

NOW THEREFORE pursuant to section 44.1(6) of the UCA, the BCUC orders as follows:

1. The BCUC accepts the FortisBC Inc. 2021 Long Term Electric Resource Plan, including the 2021 Long Term Demand-Side Management Plan as being in the public interest.

6.1 Please confirm that if the Commission makes its approval contingent upon resolution of specific issues which it perceives to be in the greater public interest, FBC will expect to determine if these issues and the proposed resolution are acceptable to FBC and, if so, FBC would seek to adopt these in compliance filings or through other compliance means.

<u>Response:</u>

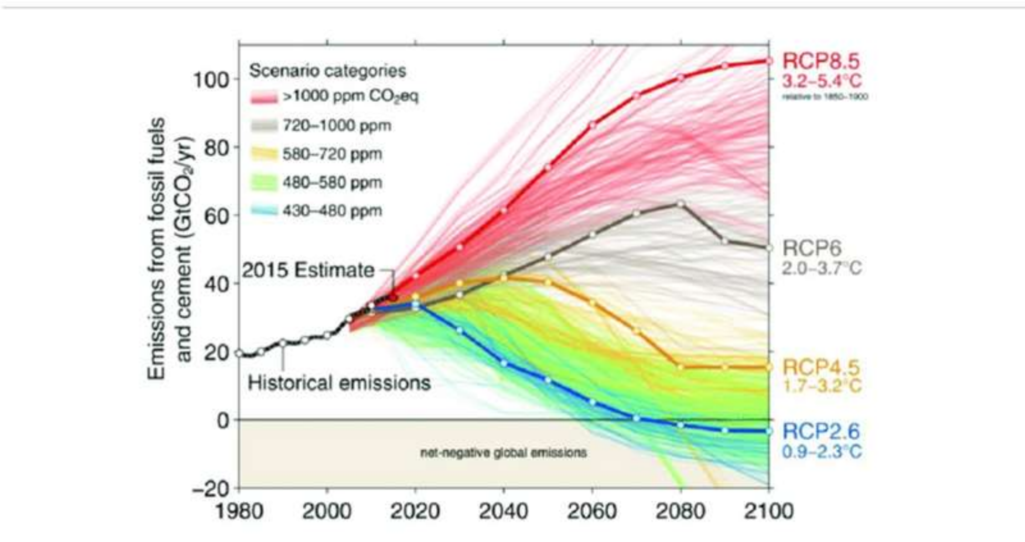
Pursuant to section 44.1(6) of the UCA, the BCUC must, after reviewing the LTERP, accept the plan as being in the public interest, reject the plan, or under section 44.1(7) accept or reject, a part of a public utility's plan, as it did in the case of the Company's 2016 LTERP.

FBC does not expect that the BCUC would accept the LTERP contingent on the resolution of certain issues, but rather would accept the LTERP while providing specific directives with which FBC is required to comply. Such directives could contain future requirements such as compliance filings. FBC could, if in its opinion the directives warranted, request a variance or reconsideration of portions of the Decision in accordance with established BCUC procedure.

2. PLANNING ENVIRONMENT

7. Reference: Exhibit B-1, Page 18

Climate change is dramatically changing the external environment in which FBC operates and has prompted governments at all levels to enact environmental policies aimed at reducing GHG emissions. Over the LTERP planning horizon, climate change has the potential to impact FBC's supply in terms of its hydro-electricity generation, how much electricity FBC's customers require, and FBC's transmission and system infrastructure planning. Recent studies indicate that rising temperatures and changes in precipitation patterns will occur over the next century.[17]



7.1 Please confirm that the RCP 8.5 and RCP 2.6 refer to the degree of warming as 8.5 watts per square meter or 2.6 watts per square meter, that would be related to the carbon emission concentrations in ppm giving rise to the global warming.

Response:

Confirmed.

7.2 Please provide the climate change scenarios (high, middle, and low) FBC is using to create the potential scenarios for impacts on FBC's customers and on FBC's system.

Response:

Please refer to the response to BCUC IR1 15.5 for the climate change load driver impacts for each load scenario.

8. Reference: Exhibit B-1, Page 36

> This section provides an examination of the customer demand environment to assess how technology, customers' energy needs, and the types of loads are changing and how the relationship between the customer and the utility continues to evolve. The ways in which customers use, monitor, and generate electricity is evolving, presenting both challenges and opportunities for FBC in meeting the future needs of its customers. Technology is a large driver in this evolution, impacting how customers connect and interact with FBC and influencing the supply of and demand for electricity on the system. This, in turn, has implications for FBC's services and rate offerings which need to appropriately reflect how customers use electricity.

Given the significant impacts of technology developments, particularly over the course of 20 years, it is surprising that the FBC does not have a significant section on the technologies that can impact planning for FBC and their potential courses of development over the 20 years planning period.

8.1 If the Commission asked for FBC to be more proactive in its planning documents with respect to the long-term developments of important technologies and their impacts upon long term planning for FBC, would FBC find it appropriate to have a fulsome ongoing review of technology development? Please explain.

Response:

While FBC does not have a specific section of the LTERP on the technologies that can impact planning for FBC and their potential courses of development over the 20-year planning period, FBC does include discussion and analysis of important technologies and their impacts throughout various sections of the LTERP. Examples of these include discussions of technologies related to:

- Strategies for mitigation of home EV charging (Section 2.3.2);
- Tools for changing the way customers interact with FBC and the information available to both customers and FBC regarding energy use (Section 2.3.3);
- Advanced analytics that provide customers with deeper insights into their energy use and are changing the way DSM programs are marketed to customers (Section 2.3.7.3);
- Load drivers including rooftop solar PV paired with battery storage, hydrogen production and carbon capture and storage (Section 4.1.1 and Appendix H); and
- Supply-side resource options including battery storage and solar PV.

FBC considers this level of discussion and analysis related to technology developments appropriate for the LTERP. FBC would consider any recommendations or directives from the BCUC for future LTERPs in this regard.

9. Reference: Exhibit B-1, Page 36

- Supporting EV adoption by funding charging stations, providing rebates for chargers and developing strategies for managing EV charging impacts during peak demand periods;
- Promoting informed electricity use by providing more detailed and up-to-date consumption and end use data;
- Supporting small customer-owned clean or renewable distributed generation with the net metering tariff;
- Improving the management of customer interconnections to accommodate and attract new emerging large loads, and
- Providing customers with cost-effective DSM programs to reduce their energy consumption.

9.1 Please describe what FBC anticipates will be developed with respect to self-driving vehicles and or so called robo-taxis, particularly given that there are several ongoing trials at reasonable scales underway and the technology is continuing to develop toward clearance for larger-scale commercial operation.

Response:

FBC anticipates that it will still be several years (i.e. 10 or more) before the technical, regulatory, and customer acceptance challenges related to self-driving (autonomous) vehicles are sufficiently addressed to allow widespread adoption. Further, the impact of widespread self-driving vehicle adoption on electric load is not clear. FBC will continue to closely monitor this technology, but at this time, does not have sufficient information to include any effects over the 20-year timeframe of this LTERP.

9.2 Please describe what FBC anticipates the charging regimes will be for these types of autonomous vehicles and whether or not they may be required over the course of the 20-year planning timeframe.

Response:

FBC considers it premature to speculate on charging regimes for autonomous vehicles, particularly given the long timeframe expected before widespread adoption of this technology, as discussed in the response to CEC IR1 9.1.

It is possible autonomous vehicle transportation patterns may look similar to those for human-driven EVs (as the same number of people would still need to get from point A to point B). It is also possible that the autonomous transportation will increase miles travelled (and therefore total energy use) by lowering the cost, reducing the stress associated with, and improving the safety of, passenger vehicle travel.

Given the above, there is too much uncertainty to include any changes in load due to autonomous vehicles.

9.3 Please describe the technology paths that distributed generation harnessing solar energy may take over the 20-year long-term planning timeframe.

Response:

FBC does not have internal resources dedicated to following technical developments in solar generation, but monitors growth trends in its service area and endeavors to keep abreast of industry changes. There are a number of comprehensive independent resources available that examine developments in the solar industry, such as the 2015 Massachusetts Institute of Technology study that can be found at the following link: https://energy.mit.edu/wp-content/uploads/2015/05/MITEI-The-Future-of-Solar-Energy.pdf.

In addition, the International Renewable Energy Agency published a report in 2019, which can be found at the following link:

https://irena.org//media/Files/IRENA/Agency/Publication/2019/Nov/IRENA_Future_of_Solar_PV_2019.pdf.

9.4 Please comment on the EIA's assertion that solar energy is now the cheapest form of energy available and is set to displace fossil energy in the future.

Response:

Renewable resources, such as solar as well as wind, could potentially displace a large portion of the total energy generated from fossil fuel resources in the future. However, the use of some form of fossil fuel to provide firm and dependable capacity to meet peak winter demand in the Pacific Northwest is likely required for some time until alternative dispatchable capacity resources are more cost effective on a larger scale and/or electrical storage capabilities further mature.

The most cost effective energy resource available to FBC, based on current forecasts, is the wholesale market. The market forecast indirectly reflects assumptions around an anticipated build out of renewable resources in the Pacific Northwest including solar. Increased renewable generation from solar resources could result in lower power prices in the middle of the day, and potentially even lower overall average market prices, but may also create greater price volatility as well as dependency on fossil fuel resources during ramping periods for capacity purposes.

9.5 Please comment upon the breakeven point for locally-sourced solar energy to displace grid electricity at current and future grid electricity prices, and whether or not the development of this resource may have a significant effect over the next 20 years for FBC.

Response:

Using a simple payback model, excluding consideration of the opportunity cost of the initial capital, inflation, or potential rate increases, it would take just over 16 years for a customer to recoup the current initial cost to purchase and install a typical PV system in the Okanagan.

This analysis assumes an 8 kW DC system installed in Kelowna at a cost of $18 thousand, which local installers have informed FBC is considered typical. Such a system would produce approximately 9,150 kWh[1] annually.

At an average price of $0.125 per kWh, $18 thousand would purchase 144,000 kWh, which a system with an annual panel efficiency loss of 0.5 percent would take just over 16 years to produce.

While the price of solar PV modules has fallen considerably in recent years, this trend reversed in 2021 due to supply chain issues and rising prices in input materials. This makes forecasting over the near to medium term difficult. However, over the longer term, FBC expects that payback periods for solar installations will continue to shorten.

FBC continues to monitor the development of solar installations in its service area, but expects that the proliferation of PV will not be a significant issue in resource planning.

9.6 Please comment upon the technology developments for conservation and efficiency of energy leading to impacts on the FBC long-term plans.

Response:

As technology continues to develop, there is an evolution towards “smart” or “connected” devices, which has a number of implications for FBC. These devices provide new ways for customers to

[1] According to the online calculator available at https://pvwatts.nrel.gov/pvwatts.php

interact with their existing electricity-consuming equipment within their homes and buildings, as well as creating new electricity-consuming equipment that is purposely built to function with these devices (e.g., smart home hubs). These technology developments create opportunities for conservation and energy efficiency and the utility as a whole in a variety of ways. Section 2.3.7.3 of the LTERP describes how advanced analytics can support DSM and provide customers' deeper insight into their energy use. Additional technologies creating opportunities for conservation and energy management include:

1. New methods of control for electricity-consuming end-uses that present opportunities for energy savings in buildings without installing new equipment;
2. Devices that previously have not had methods of control can now be scheduled to operate during non-peak hours, reducing electricity demand during peak periods;
3. New purpose-built equipment may have opportunities to reduce its energy consumption as the technology becomes more sophisticated;
4. New methods for utilities to potentially provide messaging direct to customers through their devices; and
5. New methods for customers to potentially access their utility information.

10. Reference: Exhibit B-1, Page 37

> At this time, it is uncertain if some of the behavioural changes resulting from the COVID-19 pandemic will be shorter term in nature or have longer lasting effects. For example, it is unknown if office workers currently working from home instead of the office will return to the workplace and if they will return to the typical five-days-a-week workplace pattern or something different. It is likely that the degree of economic recovery and growth will continue to influence the evolving customer electricity demand from drivers such as EVs and large load sectors.

10.1 Please provide FBC's expectation for the probability of another significant economic event like the COVID-19 pandemic coming and impacting the course of planning for the next 20 years.

Response:

FBC does not have an expectation for the probability of another significant economic event like the COVID-19 pandemic coming and impacting the course of planning for the next 20 years. FBC does not have, and is not aware of, any data that could be used to objectively develop such a probability.

10.2 Please confirm that the future forecasting FBC is using appears to have 20 years of unwavering growth and no anticipation of a possible future disruption.

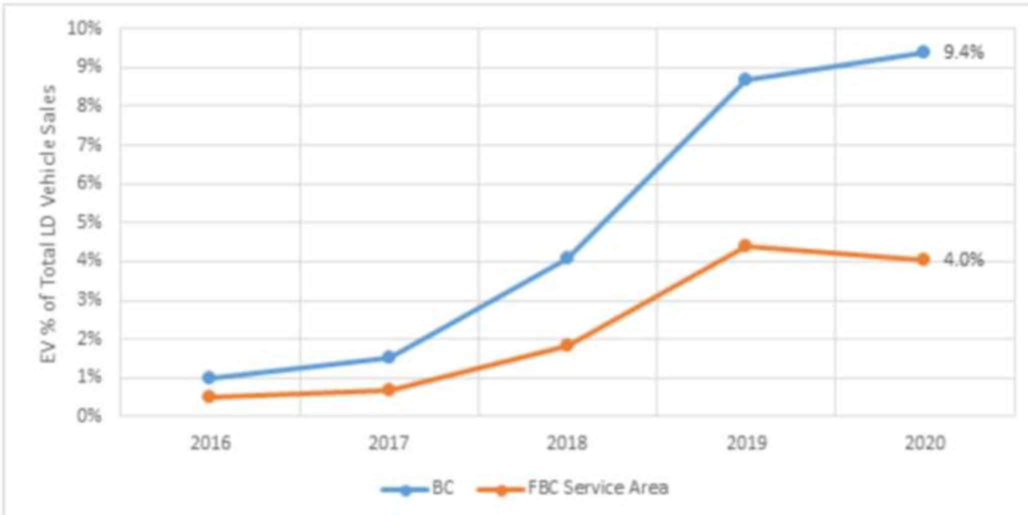
Response:

FBC does not expect to see "20 years of unwavering growth and no anticipation of a possible future disruption". Rather, FBC expects that the future growth will occur within the uncertainty bands as discussed in Section 5 of Appendix F.

FBC's Reference Case load forecast is based on the growth of intrinsic historical load drivers per the BAU load forecast plus EV charging impacts and highly certain large loads. It is considered a snapshot of a moment in time and represents FBC's current expectations for future load growth. However, FBC's future load growth will change over time, the combined impacts of various load drivers will change, and new load forecasts will be developed in future LTERPs.

11. Reference: Exhibit B-1, Page 38

Figure 2-5: Light-duty EV Sales as a Percent of Total Light-duty Vehicle Sales[60]



11.1 Please comment on whether or not the pandemic uncertainties have persisted through into 2021 and provide the evidence available to define the degree of rebound given the levels of vaccine protection being reached in the community and the pending confidence in a return to some version of normalcy.

Response:

FBC believes some pandemic uncertainties have persisted into 2021, although it is difficult to quantify their extent. FBC does not have 2021 EV registration data yet, but growth in the use of FBC's public fast charging network is a likely indicator that the number of registered EVs is increasing within BC. FBC notes that the overall number of charging events recorded at FBC's fast charging stations from July to October 2021 is over double the number of events recorded for the same period in 2020.

12. Reference: Exhibit B-2, Page 44

> The increased availability of "smart" home apps is likely to drive customers' interest in controlling their energy use. Remote monitoring and control of energy-consuming devices is becoming increasingly commonplace with the advent of products such as "smart" thermostats. These thermostats monitor building occupancy patterns and will change temperature setpoints to reduce energy use when buildings are unoccupied. They also allow remote temperature adjustments via a web browser or mobile phone app. Automation technology also allows better control of devices other than thermostats in customers' homes and businesses. Lighting controls can turn off or dim lighting based on room occupancy. Hot water controls could anticipate higher demand periods, reducing temperature setpoints at other times. Further discussion of this smart home technology as it relates to FBC's DSM programs and incentives is provided in Section 2.3.7.

12.1 Please provide any evidence FBC has showing its understanding of the energy use technologies customers use and the potential for further improvements in their efficiency.

Response:

In 2021, FEI and FBC jointly commissioned a prefeasibility study from the Posterity Group to review the energy and non-energy benefits of Connected Home technologies within FEI natural gas and FBC electric service territories. The study provided a technical assessment of a number of different connected home technologies followed by their market characterization, barriers and risks, and quantified their energy savings potential. This study was informed by extensive literature reviews, market research, and interviews with several market actors including other utilities, subject matter experts, and Smart Home integrators within British Columbia.

FBC will potentially use the study to support development of the next iteration of residential appliance rebates and future demand response offers.

12.2 Please comment upon the limitations in the CPR with respect to considering future technology path potentials and relying on known existing available technology options.

Response:

The 2021 FBC Conservation Potential Review did not consider future potential DSM measures not already identified as having technical, economic, or market potential at the time of the study. All DSM measures included in the technical, economic, and market potential evaluation were known existing and available technologies.

Thus, a key limitation of Conservation Potential Review is that it cannot reflect future DSM measures that will likely emerge during the planning period. This results in a more conservative estimate of potential DSM savings for resource planning than will likely occur. However, this assumption was made as there is no assurance that future potential DSM measures will be applicable, available, cost-effective, and/or competitive versus other resource options.

FBC's 2019-2022 DSM Plan included funding to identify and assess innovative technologies for consideration in both future DSM programs and resource planning.

13. Reference: Exhibit B-1, Page 45

> Small-scale distribution-level generation installations continue to be installed by customers driven primarily by the following considerations:
>
> - The perception that distributed generation is "greener" than utility generation.
> - The desire to become more energy-independent.
> - The perception that they are saving money.[66]
>
> Small-scale distributed generation technologies present some challenges for FBC both from a technical standpoint and in terms of customer equity. These include the following:
>
> - Safety – potential for back-feeding onto the distribution grid must be properly addressed.
> - Grid stability – distribution grid must be able to handle unpredictable distributed generation output without causing power quality problems for other customers.
> - Equity – the structure of current rates can lead to net metering customers avoiding the cost of being connected to the FBC system – meaning those costs must be recovered through the rates of non-net metered customers.

13.1 Please comment upon whether or not FBC would consider and/or participate in development of small-scale distributed generation installations that had elements shared in a neighborhood and facilitated by municipalities and/or utilities because of potential efficiencies.

<u>Response:</u>

Provided that the installations described in the question are consistent with the LTERP objectives discussed in Section 1.2 of the Application, FBC would consider participation and partnership in developments such as those noted in the question.

13.2 Please provide FBC's evidence with respect to the degree to which grid battery technologies could enable safe stabilization of local small-scale generation variability impacts on the voltage and energy supply of other customers.

<u>Response:</u>

As described in the response to BCUC IR1 23.1, FBC is not presently undertaking further study to understand the impacts of distribution generation (DG) because the near-term impacts of DG facilities are relatively low. It is FBC's understanding that storage technologies such as grid-scale batteries can act to smooth fluctuations in both demand and generation. As such, battery technologies could play a role in supporting grid stability at higher levels of DG penetration.

14. Reference: Exhibit B-1, Page 49

> 7 Should an emerging use, such as EVs for example, be shown to have a unique usage profile that impacts costs, the Company may need to consider rate options that reflect such new or changing electricity use by its customers. By designing and pricing rates on a cost basis, any benefits or incremental costs that result from the widespread adoption of new technologies will predominantly accrue to those customers that choose to participate without unduly impacting the rates of other customers.

14.1 Please describe the types of cost impacts that EV charging can impose on the FBC electrical power delivery system.

Response:

As discussed in Section 2.3.2, increased consumer adoption of EVs in BC has the potential to place significantly greater demands on utility infrastructure. This is particularly true if charging behaviour is left unmanaged and the majority of EV owners charge their EVs at the end of the workday, adding significant load to the system during FBC's peak demand period. This scenario may result in the need to upgrade FBC's electrical system at the distribution and transmission level (e.g., distribution feeders, substation transformers, and transmission lines), along with the associated costs.

14.2 Please provide the quantitative 2040 potential long-term consequences, or range of consequences, regarding cost impacts EV's could impose on the FBC system.

Response:

FBC estimated the projects required to meet a Kelowna-area peak load level of 550 MW in Table 6-6. The Deep Electrification, Diversified Energy Pathway, and Alternate scenarios' peak demand requirements each exceed 550 MW by 2040, before mitigation, and so would have an additional estimated project cost of $710 million in order to meet the additional peak demand by 2040. If FBC is able to reduce the amount of incremental EV peak demand and the Kelowna load level remains below 550 MW, then some of the projects in Table 6-6 may not be required before 2040.

The specific cost impacts on the entire FBC system will be determined by the location and the total amount of EV charging load. At this time, FBC is unable to speculate further regarding the cost impacts given the large number of possible scenarios.

14.3 Please provide the types of rate designs FBC would need to be considering to fairly and justly allocate costs to the appropriate customer rate classes.

Response:

The referenced passage was intended to indicate that to the extent that widespread adoption of a new technology creates a segment of customers that have a load profile and/or load factor distinct from those reflected in current rates, a new rate class may be justified.

The structure and pricing of any new rate would be driven by the costs to the utility that this new segment of customers caused as determined by a cost-of-service study.

FBC does not anticipate that the resulting rates would necessarily be structured markedly different from existing rates, but would ensure that the recovery of fixed and variable costs appropriately follow the principle of cost causation. This could, for example, consider whether the contribution to system peak varied significantly from similarly sized customers, or, where the ability to avoid energy-based charges may favour a rate emphasizing an alternate means of recovering fixed costs (such as a demand-based rate for net metering customers).

15. Reference: Exhibit B-1, Page 51

> A limited number of utilities are starting to enter the marketplace and selling energy efficiency products like LED lamps, low-flow showerheads and smart thermostats.[71] In addition to on-line stores, utilities are providing information and/or promotion about trade allies' businesses and forwarding offers from third parties. They are also making appliance and equipment comparisons and giving recommendations. Utilities that provide these services are perceived, by customers, to be the energy efficiency authorities and are helping to meet customer demand.

15.1 Will FBC consider entering the downstream from meter market for energy efficiency some time over the 20-year planning horizon through an independent subsidiary?

Response:

FBC has no plans to enter the downstream from meter market for energy efficiency at this time, either through its regulated operations or an independent subsidiary.

15.2 Could FBC add significant value to the public interest if it were to develop greater customer interaction with respect to energy conservation and efficiency? Please explain why or why not.

15.2.1 If yes, please describe the types of actions FBC could undertake to do so.

Response:

FBC interprets "greater customer interaction" as referring to FBC entering the downstream-of-the-meter market for energy efficiency.

If FBC were to sell energy efficient products directly to the customer, there could be some benefits and drawbacks. Some potential benefits to customers include:

1. Streamlining a significant portion of the FBC incentive application process;
2. FBC could provide equipment recommendations and vet energy efficiency products to improve project performance; and
3. For some equipment with smart controls, if the customer agreed, FBC could pre-program the products to participate in future DSM program (for example, pre-programmed smart learning thermostats that would be ready to participate in a future demand response program).

Some potential drawbacks to customers include:

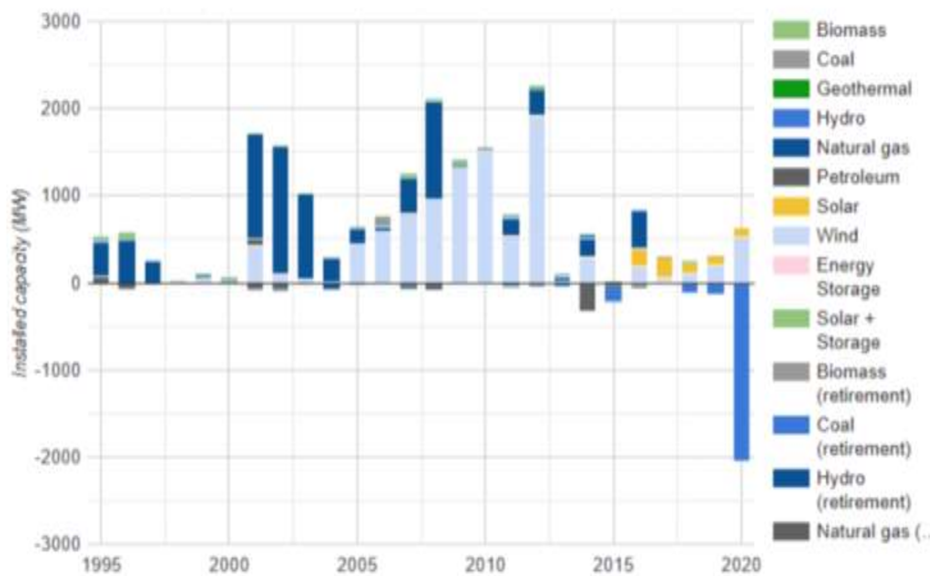
1. FBC does not have experience as a product retailer, thus, startup and operations may be challenging and subject to a learning curve; and
2. FBC may not be able to achieve the economies of scale for equipment purchasing compared to other retailers, potentially increasing costs.

Regardless, FBC cannot undertake actions to enter the downstream from meter market for energy efficiency due to prohibitions under the Retail Markets Downstream of the Utility Meter (RMDM) Guidelines established by the BCUC.[2]

[2] https://docs.bcuc.com/documents/Guidelines/RMDMGuidelns.pdf

16. Reference: Exhibit B-1, Page 57

Figure 2-13: Pacific Northwest Generating Capacity Additions and Retirements[79]



16.1 Please discuss the technologies for integrating the variable renewable energies emerging as preferred supply options, without resorting to GHG-producing fossil-fueled power plants with the capability of responding to the fluctuations and provide FBC's understanding of their technology paths over the next 20 years, specifically covering battery technologies, electrical grid operations management opportunities, and potential customer demand response management.

Response:

FBC's CPA storage accounts, storage hydro, pumped storage hydro, batteries, or other storage technologies could all be used to integrate variable renewable technologies. Each technology has its own advantages and limitations.

FBC has evaluated each of these technologies in its current form in its portfolio analysis. FBC does not have the ability to predict with certainty the detailed technology paths for these or other potential storage options and customer demand responses over the next 20 years. As these technologies and options are further developed or commercialized, they may be included in future resource plans.

17. Reference: Exhibit B-2, Page 59

> BC Hydro indicates that it plans to offer a market-price based renewal option to existing clean or renewable independent power producers with electricity purchase agreements expiring in the next five years. There are approximately 20 existing clean or renewable projects, that produce a total of roughly 900 GWh, with electricity purchase agreements set to expire before April 1, 2026.[90] Depending on how many expiring EPAs are renewed by BC Hydro, there may be opportunities for FBC to acquire power relating to these expiring EPAs on a cost-effective basis in the future.

17.1 Please provide FBC's expectation on whether or not these expiring EPAs, which represent an opportunity for cost effective supply for FBC's future needs, will be available for negotiation with FBC to determine if suitable arrangements can be made.

Response:

While FBC is uncertain as to which EPAs will be renewed by BC Hydro, FBC does expect that a portion of the power related to these expiring EPAs will be available for negotiation with FBC.

17.2 Could arrangements with long life power generation assets be a favourable replacement for FBC's PPA arrangements with BC Hydro? Please explain why or why not.

Response:

Arrangements with long life power generation assets could be a favourable addition to FBC's power supply portfolio, but that is highly dependent on resource specific characteristics. The value of a resource ultimately depends on the alignment between the time of delivery of energy and the forecast utility resource gaps as well as its complementary nature to existing resources and other incremental resources over the planning horizon.

Section 11.3.6 of the LTERP did evaluate several portfolios that did not include the renewal of the PPA. In addition, as stated in BC Hydro's draft 2021 IRP,[3] expiring EPA power may be available at market-based rates. However, expiring EPA power was not evaluated within the FBC LTERP. If a suitable opportunity should arise, FBC will bring it forward in an application to the BCUC.

Given the resource options available within the LTERP, the LRMC values for the portfolios without renewal of the PPA (portfolios F4 and F5) were higher than those with PPA renewal. The PPA is one of the lowest cost resource options and replacing it with other supply-side resource options increases the LRMC value. It should also be noted that in the portfolios without PPA renewal, a

[3] DRAFT 2021 Integrated Resource Plan (bchydro.com)

large and diverse portfolio of intermittent renewable resources was required to replace the dependable capacity of the PPA while also accommodating the incremental capacity requirements of the Reference Case load forecast.

The flexibility of the PPA makes it a valuable planning tool and resource that provides many benefits to FBC, and makes it very difficult to economically replace. While the PPA ensures access to a maximum of 200 MW of demand and 1,752 GWh of energy on an annual basis, there are provisions within the contract that allow FBC to shape and scale up or scale down its usage, along with corresponding costs, based on requirements. This flexibility provides access to firm power when necessary and the ability to mitigate power purchase expense when the market is favourable or when loads are lower than forecast by reducing purchases.

18. Reference: Exhibit B-2, Page 64

> Therefore, FBC plans to ensure it has sufficient capacity resources available in place to meet forecast peak demand. The month of June is an exception due to the abundant freshet hydropower available in the market. For the purposes of this LTERP, FBC assumes that it will be able to purchase a limited amount of June capacity from the market, on a forward block basis as opposed to in 'real time', reliably and cost-effectively until 2030. After that time, FBC has assumed capacity self-sufficiency for all months, including June, given the longer-term market risks.

18.1 Has FBC determined that it will always be self-sufficient after 2030, or will FBC remain open to take advantage of electricity markets when for whatever reason they show surpluses of energy and or capacity? Please explain.

<u>Response:</u>

FBC confirms it has determined that it will plan to be capacity self-sufficient after 2030 at expected load levels based on the Reference Case load forecast for the reasons given in the Application in section 2.4.4.1 on page 64. However, FBC does not plan to be energy self-sufficient, and is currently showing energy gaps in the planning horizon starting in 2023. FBC plans to use wholesale market energy in order to meet those requirements. Operationally, if available, FBC also expects to continue to use market capacity to meet loads that are higher than expected as well as to displace PPA capacity purchases where it is reasonable to do so. In the 2016 LTERP decision, the BCUC determined that energy self-sufficiency was not in the public interest.

18.2 Does FBC consider that such trade benefits are in the public interest? Please explain why or why not.

<u>Response:</u>

FBC confirms that there are trade benefits to be had by using market energy to meet planning gaps over the long-term horizon. Individual utilities are increasingly investing[4] in intermittent, renewable resources, and many are overbuilding these resources in order to gain the amount of dependable capacity required to meet their peak demand requirements. As a result, there is increased potential for large amounts of lower-priced surplus power to be available in the region at times when other utilities' own loads are lower than forecast or their energy supplies are higher than forecast. Access to economic wholesale power is a benefit, which is in the public interest.

However, these trade benefits do not necessarily hold true for the use of market capacity to meet expected load on a planning basis. The Northwest region is currently facing a capacity deficit, and the resulting risks are discussed further in Section 2.4.4.1. If utilities plan to rely on the

[4] As illustrated in Appendix D – PNW Electric Utilities IRP Comparison Table of the Application.

capacity surplus of others, especially in regards to intermittent renewables or anticipated market capacity available[5] to purchase in the wholesale market, to meet expected demand, reliability and price risks will increase for the entire region.

[5] In Portland General Electric's 2019 IRP, Appendix E – Market Capacity Study, a range of potential surplus market capacity is determined, and illustrates the assumed market capacity available to either PGE, or other utilities, that plan, or could be, to rely on the same available market capacity for their own planning purposes.

19. Reference: Exhibit B-2 Page 67

> For the carbon price scenarios, FBC has made assumptions based on the current price of carbon in BC and the Canadian federal government announcement in December 2020 regarding the federal government's proposal to increase carbon pricing to reach $170 per tonne by 2030.

19.1 Please provide FBC's 2030 to 2040 assumption with respect to carbon tax pricing and give the reasons for adopting those assumptions.

<u>Response:</u>

FBC has developed its carbon price scenarios based on different assumptions for each of the four (i.e., base, high, medium, and low) scenarios.

For the base case, FBC has assumed a carbon tax of $45 per tonne (in nominal terms) in 2021 as the base case after which time it increases by $5 per tonne to $50 per tonne (in nominal terms) in 2022 (consistent which current legislation where the BC government's current carbon tax of $45 per tonne effective April 1, 2021, then increases by $5 per tonne effective April 1, 2022 to $50 per tonne). After that time, the base case holds the carbon price constant in real terms for the duration of the forecast ending in 2040, on the assumption that the carbon tax is increased to keep up with inflation over time.

FBC's high case is based on the assumption of the federal government's announcement that it is planning to increase the carbon tax beyond the $50 per tonne level as part of a push to meet and surpass Canada's goal of reducing GHG emissions by 30 per cent below 2005 levels by 2030. In this scenario, the price rises by $15 per tonne per year for eight years beginning in 2023 to reach $170 per tonne in 2030. After 2030, the FBC high case includes annual increases of $15 per tonne (in nominal terms) to 2040. The high case reaches $140 per tonne (in real terms) in 2030, which is equivalent to $170 per tonne proposed by the federal government, and continues to increase by $15 per tonne (in nominal terms) until 2040.

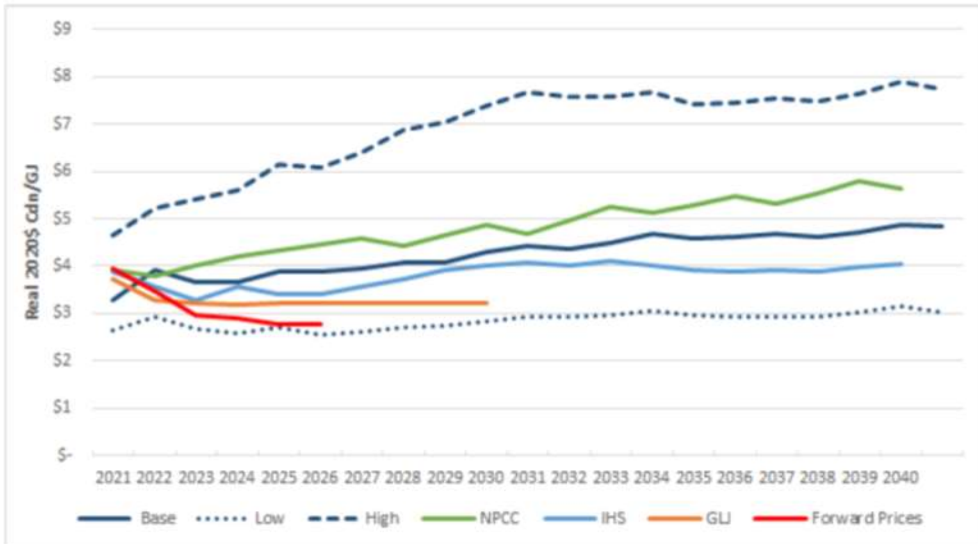
FBC has also included a more moderate, medium case pricing scenario which assumes annual increases of half of the $15 per tonne increases, or $7.50 per tonne (in nominal terms) going out to 2040.

The low case scenario is based on the assumption the carbon tax will be removed beginning in 2023 and stays at zero for the remaining forecast years through 2040.

Please also refer to the response to CEC IR1 22.1.

20. Reference: Exhibit B-2, Page 70

Figure 2-16: Comparison of Sumas Price Forecasts and Forward Prices



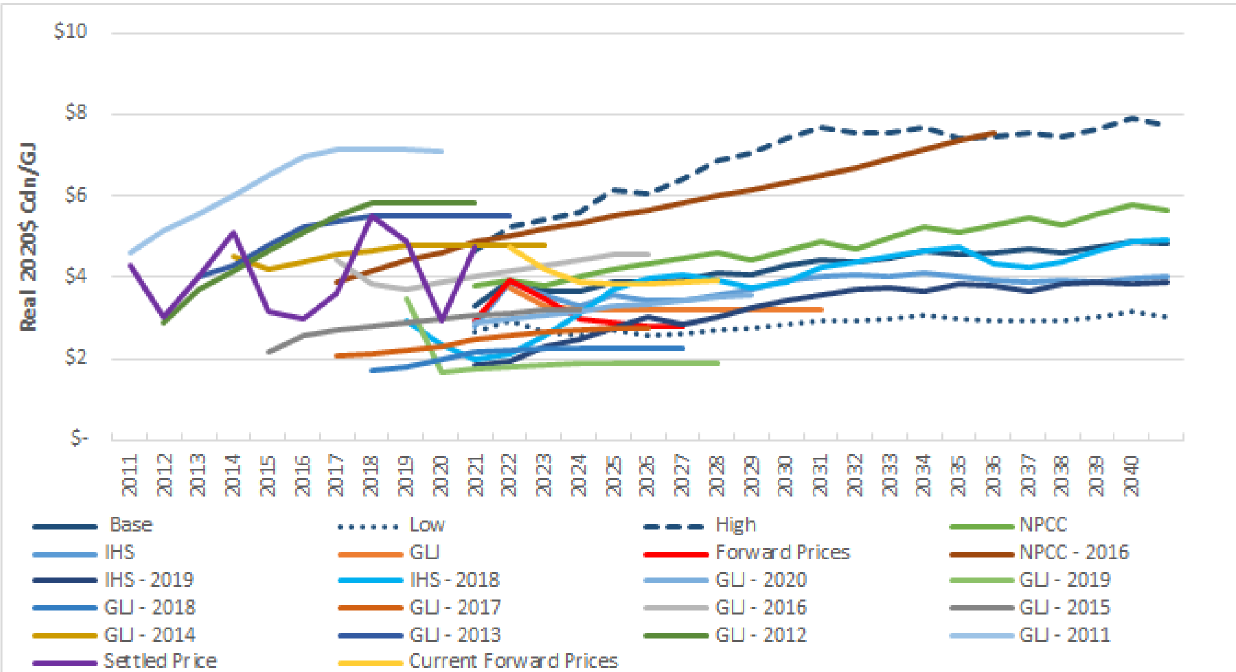
20.1 Please provide historical forecasts from these same sources over the last 10 years and juxtapose those to the subsequent reality in the energy markets.

Response:

The figure below has been updated to include historical price forecasts over the last ten years. The updated figure includes additional price forecasts from NPCC (2016 Forecast), IHS (2018 - 2019 Forecast), and GLJ (2011-2020 Forecasts), along with the current forward prices as of December 2, 2021 and the settled prices at the Sumas market hub. All prices are in real 2020 dollars. FBC has interpreted "juxtapose those to the subsequent reality in the energy markets" as meaning how the previous price forecasts compare to actual market settlement and current forward prices.

Generally, the price forecasts have been both higher and lower when compared to the settled market prices, as certain assumptions about supply and demand change over time. The settled market prices have fluctuated significantly over the past 10 years and have led to a wide range of price forecasts, as the price forecasts can be based on factors including the same supply and demand factors impacting market forward and settled prices. For example, from 2011 to 2014, the GLJ price forecasts were higher than the settled market prices and the other later price forecasts, reflecting previous years' higher settled prices. From 2015 to 2020, the GLJ, NPCC and IHS prices forecasts were generally lower than earlier price forecasts and the settled prices as market prices began to trend lower.

The actual prices from 2018 to 2021 have settled higher than the most recent IHS price forecasts mainly due to pipeline infrastructure constraints causing prices to settle higher during peak demand periods and cold weather events that occurred in the 2019/20 and 2020/21 winter periods, among other factors. The current forward prices as of December 2, 2021 average $3.81 per GJ for 2022 to 2026, which is above the June 17, 2021 forward prices average of $2.98 per GJ. In comparison, the base case price forecast included in Figure 2-16 has an average price of $3.81 per GJ for 2021 to 2040.



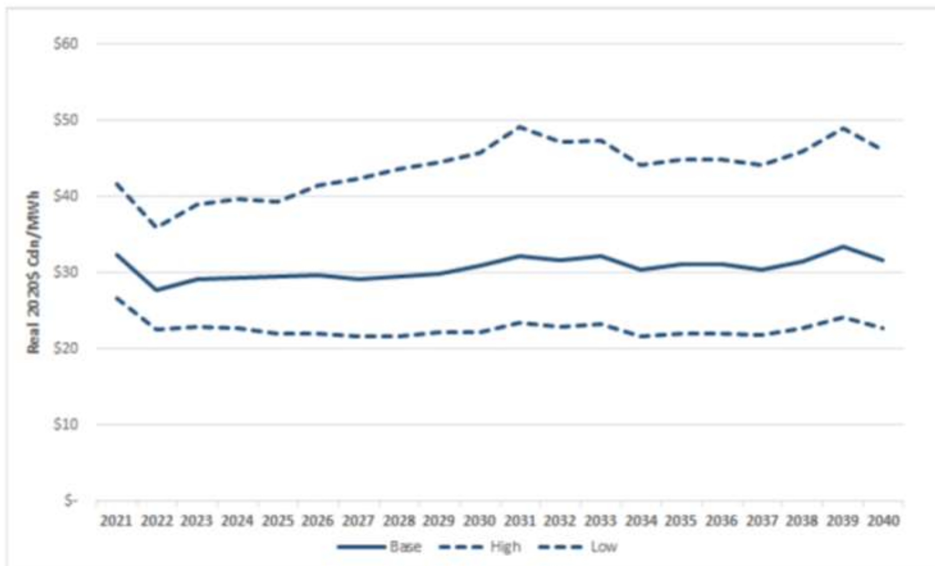
20.2 Please comment on the forward prices relative to the forecast and particularly given the price of oil recently, with respect to the validity of the forecasts.

<u>Response:</u>

Forward prices are a snapshot of where market participants are willing to transact, whereas the price forecasts are a view of certain assumptions about supply and demand factors that have been made based on current information. The forward prices included in the figure are higher than the base price forecast in 2021 and then begin to trend lower than the base price forecast after 2021. This is, in part, due to expectations for natural gas supply to rebound after decreasing during the collapse of market oil prices in 2020 that caused associated natural gas production (as a by-product of oil production) to decrease. While the base price forecast is overstated relative to the forward prices, as forward prices settle, time will tell if this continues to be the case.

21. Reference: Exhibit B-2, Page 72

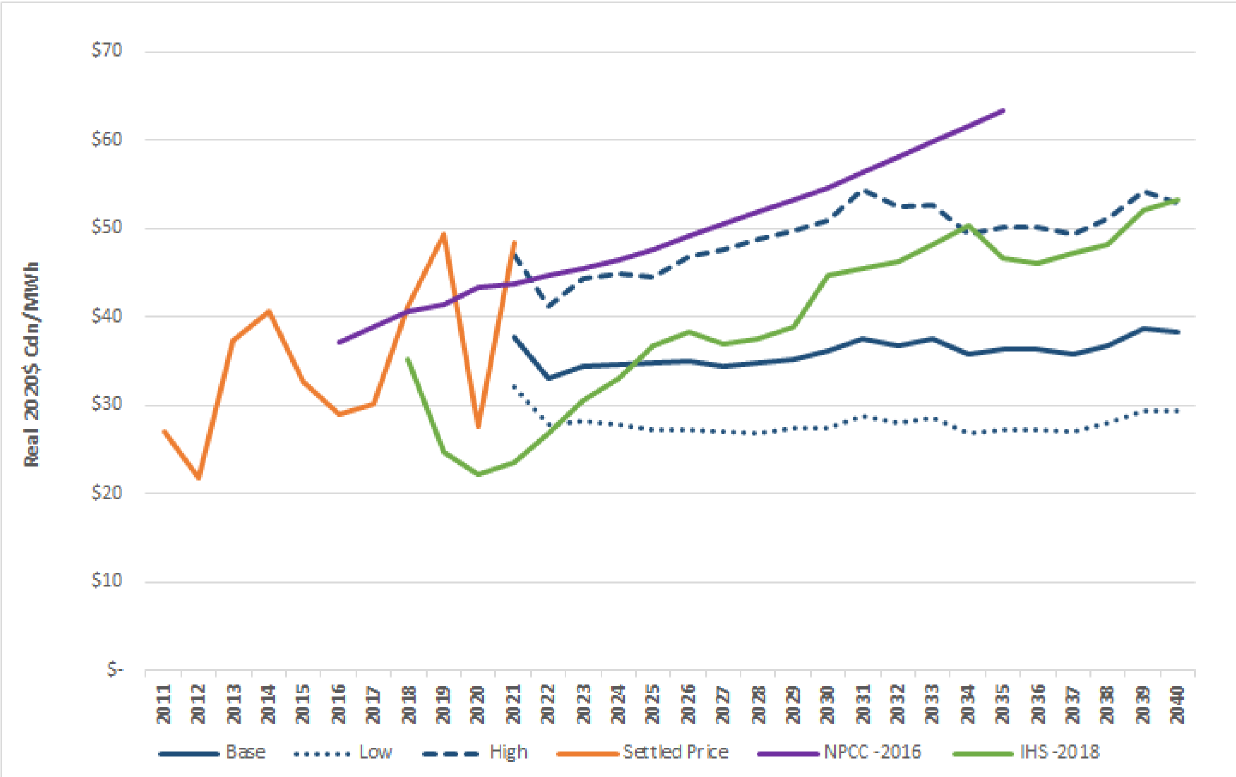
Figure 2-18: Mid-C Electricity Annual Price Forecasts



21.1 Please provide past forecast from the same source for the last 10 years and juxtapose those to the actual data of each year to enable an understanding of the forecasting accuracy.

<u>Response:</u>

The figure below includes the addition of historical price forecasts available to FBC over the last ten years. The figure includes additional price forecasts from NPCC (2016 Forecast), IHS (2018 Forecast) and the settled prices at the Mid-C market. All prices are in real 2020 dollars. The settled market prices have fluctuated significantly over the past 10 years in response to various market supply and demand dynamics. The NPCC 2016 price forecast average of $49.40 per MWh is much higher than the settled price average of $35.02 per MWh and the base price forecast average of $35.98 per MWh, due to tighter supply and demand balances at the time of that forecast. The later IHS 2018 price forecast trends lower than actual settled prices and the base price forecast for the first few years and then trends steeply upwards, increasing above the base price forecast after 2024.



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2039
2040
Base
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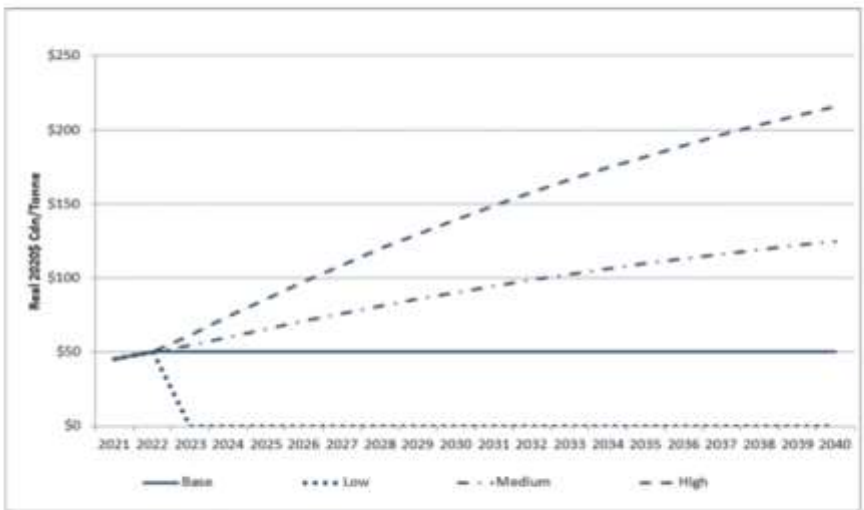
High
Settled Price
NPCC -2016
IHS -2018

22. Reference: Exhibit B-1, Page 74

Figure 2-20: BC Carbon Price Scenarios



22.1 Please explain why FBC has decided not to incorporate the federal government view of carbon pricing at $170/tonne by 2030.

<u>Response:</u>

FBC has assumed the 2021 carbon tax of $45 per tonne (in nominal terms) as the base case after which time it increases by $5 per tonne to reach $50 per tonne (in nominal terms) in 2022, which follows BC's current carbon pricing. After this time, the base case holds the carbon price constant in real terms, assuming that the carbon tax is increased to keep up with inflation over time. FBC has incorporated the federal government view of carbon pricing to reach $170 per tonne by 2030 in the high case scenario; however, the figure shown is in real 2020 dollars and not in nominal dollars. The high case scenario is based on the assumption of annual increases of $15 per tonne (in nominal terms) and reaches $140 per tonne (in real terms) in 2030, which is equivalent to $170 per tonne (in nominal terms) proposed by the federal government.

22.2 Please reconcile the data on carbon pricing in figure 2-20 and the section it is in with the data on page 67 showing that FBC has picked the $170 federal price point (is this the current BC carbon price of $45 as an existing base?).

<u>Response:</u>

Please refer to the response to CEC IR1 22.1.

3. LONG-TERM LOAD FORECAST

23. Reference: Exhibit B-2, Page 89

- BAU load forecast:
  - BC Gross Domestic Product (GDP) as forecast by the Conference Board of Canada (CBOC).[132] The CBOC forecast provides an outlook for the expected economic climate, and is used directly in the forecasts of the load growth in FBC's commercial and industrial rate classes;
  - FBC's service territory population as forecast by the Ministry of Technology, Innovation & Citizens' Services, BC Statistics branch (BC Stats), which is used to forecast the number of residential customers FBC will serve over the planning horizon;
  - Forecasts provided through annual surveys for individual wholesale and industrial customers.

23.1 Please provide any evidence FBC has that the CBOC forecast for GDP anticipates recessions and other economic disruptions for the long term, other than their short-term forecast adjustments which occur after the fact when disruptions relative to forecasts cause changes quarter by quarter to the unfolding reality.

Response:

The CBOC does not include anomalous economic disruptions in its GDP point forecasts. The CBOC would not have any credible method for forecasting such disruptions with any specificity in the long term. Evidence of this is the relatively smooth path the CBOC GDP forecasts follow. If anomalous events were predicted, the charts would not be straight or would have noticeable dips. To account for unforeseen events FBC has provided uncertainty bands (prediction intervals) for the BAU and Reference Case load forecasts in Section 3.6.

24. Reference: Exhibit B-2, Page 91

> The residential energy load for the BAU forecast is expected to increase at an average annual rate of 0.4 percent over the planning horizon. The residential customer short-term[133] growth rate is forecast to be minus 0.5 percent at the start of the planning horizon and grow at an annual rate of 0.7 percent for the remainder of the planning horizon.

24.1 Please provide the historical 10 years of residential customer use-per-customer data and the number of residential customers for each year.

Response:

The historical 10-year residential UPC and customer count are provided in the following table.

Annual Residential UPC and Customer Count from 2011 to 2020

Residential	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
UPC (MWh)	12.70	12.41	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89
Customer Count	98,795	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966

4. LOAD SCENARIOS

25. Reference: Exhibit B-2, Page 96

> Section 3 described the long-term Reference Case load forecast which is based on historical load drivers included in the BAU forecast plus any new highly-certain loads and light-duty EV charging load. FBC recognizes, however, that emerging technology, government policies, climate change and changes in how customers use and provide energy could impact load drivers that are not captured in the Reference Case forecast. This section of the LTERP discusses these emerging load drivers and some alternative load scenarios.

25.1 Given issues not factored into the long-term Reference Case, which are being presented as scenarios, please explain which load forecast FBC is using for long-term planning for firming up decision in the immediate term that will affect long-term plans.

<u>Response:</u>

The Reference Case load forecast is the resulting forecast used for long-term planning purposes in this LTERP. FBC expects that it would submit its next LTERP in approximately five years from the submission date of this LTERP, in 2026. However, if FBC's periodic assessment of the load resource balance indicates the need for new resources sooner than contemplated in this LTERP, or if FBC's access to market energy changes such that it is no longer reliable or cost effective, FBC would likely submit an LTERP or supplemental update filing sooner than 2026. At that point, FBC will develop a new Reference Case load forecast which will be used from that point forward for long-term planning purposes.

25.2 Please describe how FBC expects the Commission to settle on an appropriate load for planning purposes and how the remaining scenarios would be handled as contingencies to the main adopted forecast.

<u>Response:</u>

As discussed in the response to CEC IR1 25.1, the Reference Case load forecast is the forecast used for planning purposes in the LTERP for the entire planning horizon. FBC has also developed load scenarios to explore the potential impacts on its customer loads if growth in certain load drivers were to occur. FBC does not specifically plan to these load scenarios but rather monitors them to determine if a particular load driver or scenario warrants changes in planning in the future.

26. Reference: Exhibit B-2, Page 96

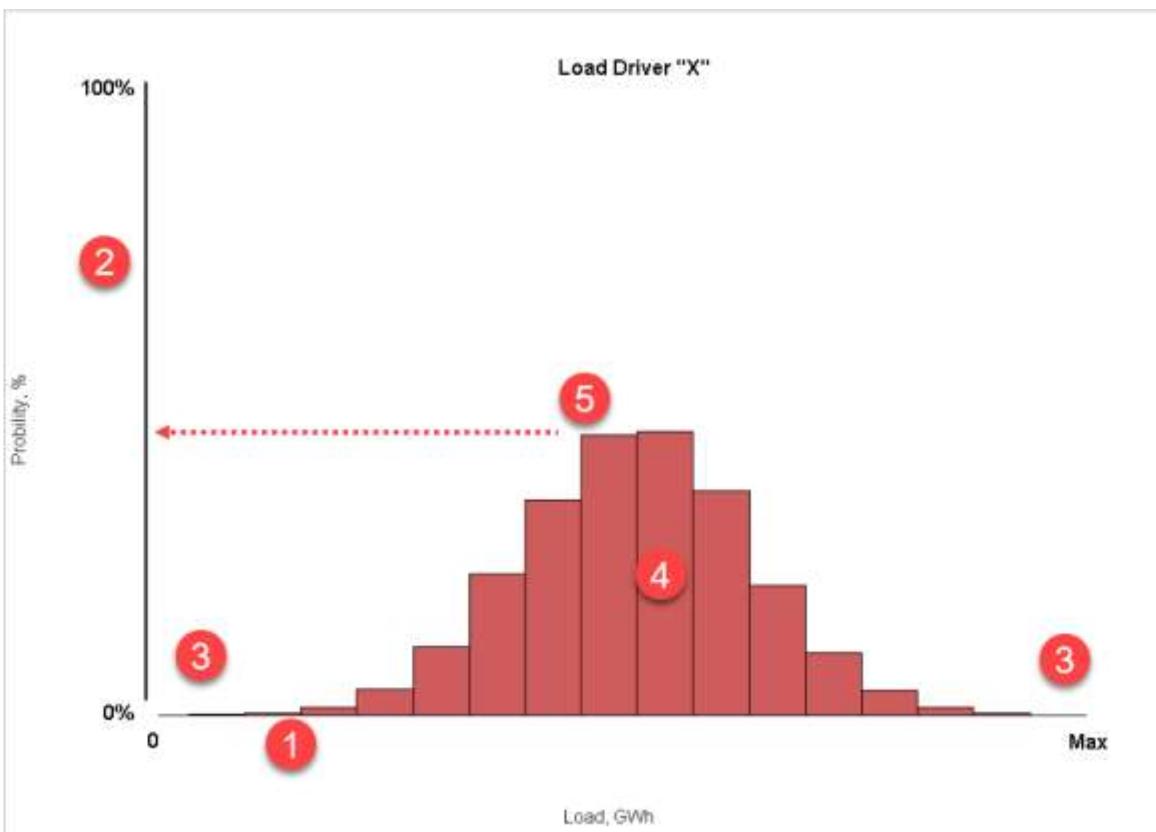
> future. As there is significant uncertainty in how these scenarios will actually play out in the future, FBC has not assigned any probabilities to them. The scenarios provide examples of what the impacts on FBC's future load requirements might be if specific load drivers occurred at specific growth or penetration levels. They are not alternate load forecasts, but are rather possible future pathways for electricity use.

26.1 Please confirm that there would be significant uncertainty in any load forecast which falls within the upper and lower bands of a forecast.

<u>Response:</u>

Not confirmed. Each scenario forecast is comprised of a number of new and intrinsic load drivers. New load drivers are ones that FBC has no historical data for, such as hydrogen production. Existing load drivers are embedded in the BAU forecast that underlies all the scenarios.

Each load driver, whether new or intrinsic, can be expected to have a range of possible outcomes in any given year. For the purposes of this response, this range is referred to as a distribution. The distribution of possible outcomes (the probabilities) can be visualized in a hypothetical histogram:



1. The possible load outcomes for load driver "X" range from 0 GWh to the maximum for this driver. The maximum is known or can be reasonably estimated.
2. The probability of any load from this driver in any year is shown on the Y axis and ranges from 0 percent (no probability of occurrence) to 100 percent (certain to occur). It is important to note that in no case is there 100 percent certainty. None of the red bars reach 100 percent.
3. The two boundary cases (0 GWh and "Max" GWh) each have near zero probability of occurring.
4. The sum of all the probabilities depicted in the red bars is 100 percent. In other words, there is 100 percent certainty that the load in any given year will fall somewhere in the distribution.
5. The peak, or most likely outcome of the distribution, is visible but there is no objective way to determine the probability associated with the most-likely value (shown as the dashed line).

Summing up the multiple load drivers, each with multiple unknowns in multiple scenarios, would not provide any useful information about the probability of any single scenario or the relative probabilities between scenarios.

Note that if the distribution of outcomes as well as the most-likely load and probability were known for all the load drivers in a scenario, an aggregate probability and load curve for that scenario could be developed. At that point, multiple scenarios could be compared on a probability basis. However, as noted above, there are no objective methods to achieve this comparison; and as a result, FBC uses scenarios solely to provide specific examples of what FBC's future load requirements might be if specific load drivers occurred at specific growth or penetration levels.

26.2 Please confirm that certainty in forecasting comes when the probability of an event approaches the most unlikely possibilities (i.e. zero probability) or approaches the most certain possibilities (i.e. 100% probability) such as what occurs at the outer bounds of the forecast where there is near certainty that these will not happen, or where there is virtually no range of probabilities and near certainty that the event will happen.

Response:

Please refer to the response to CEC IR1 26.1.

26.3 Please confirm or otherwise explain that the reason we have probabilities for events is to describe the uncertainty (i.e. having significant uncertainty is a clear reason for providing probabilities).

Response:

Please refer to the response to CEC IR1 26.1.

26.4 Please confirm that the primary reason for assigning probabilities to scenarios is to reflect the potential uncertainty.

Response:

Please refer to the response to CEC IR1 26.1.

26.5 Please discuss how FortisBC would be able to react to a load scenario being realized if FortisBC has no information about the likely causes of the scenario being realized (i.e. it is essential to have cause related information with a scenario to determine strategy and to react to and plan for an outcome).

Response:

Please refer to the response to CEC IR1 25.2.

26.6 Please discuss the following concept: “Having a simple range forecast around existing loads is obviously something FBC could react to with a different portfolio mix and if that is all that comes out of the load scenario exercise then very little has been gained from a planning point of view that could not be gained with a simple range.”

Response:

FBC has developed uncertainty bands for the Reference Case load forecast to capture potential variability in the load drivers specific to that forecast. These load drivers include, for example, EV charging and highly certain new large loads. The load scenarios, on the other hand, include load drivers that are not inherent in the Reference Case load forecast, such as, for example, significant growth in rooftop solar PV generation or hydrogen production. In addition, researching and layering each load driver on to the BAU forecast informs both FBC and stakeholders about future sensitivity to each load driver. This insight is invaluable for load drivers, such as EVs, that are both large and possibly developing earlier than once expected. Therefore, a simple range around the Reference Case load forecast would not accomplish the same purpose as the development of load scenarios driven by other and new load drivers.

27. Reference: Exhibit B-2, Page 98

> relating to the various load drivers (discussed further in section 4.1.5). FBC has no immediate plans to adjust its current resource requirements in response to these scenarios but intends to monitor load driver developments to help determine if a particular scenario or dominant load driver is emerging and will take the recommendations into consideration. FBC will explore the impacts of the load scenarios on its preferred resource portfolios as part of its portfolio analysis as discussed in Section 11.

27.1 Without a doubt monitoring is better than not monitoring at all, however action plans for key strategic issues are essential for long-term resource planning that is in the public interest. Please identify the key strategic issues in these load scenarios which will need further development actions at some point in the future.

Response:

FBC's Action Plan, discussed in Section 13.2, identifies the key strategic issues relating to the load scenarios and what actions FBC plans to take in terms of further development actions. In particular, the following Action Items specifically address this development:

- 2. Monitor potential load drivers to determine if a particular load scenario is emerging;
- 3. Contingency resource(s) assessment;
- 4. Implement program to help shift home EV charging;
- 5. Consider initiatives to manage large loads; and
- 11. Assess transmission and distribution capital infrastructure requirements.

5. EXISTING SUPPLY-SIDE RESOURCES

28. Reference: Exhibit B-2, Page 112

Table 5-1: FBC's 2021 Available Energy and Dependable Capacity Resources[141]

FBC Existing Resources (2021)	Available Energy (GWh)	Dependable Capacity (MW)
FBC CPA Entitlements	1,596	208
BPPA	919	138
BRX	79	45
PPA (Tranche 1 Energy)	1,041	-
PPA (Tranche 2 Energy)	711	-
IPP	1	-
Market and Other Contracted	302	-
PPA Capacity	-	200
WAX (net of RCA)	-	218
Total Resources	4,648	810

28.1 What is the probability of the available energy and capacity being available through FBC's facilities at these levels?

<u>Response:</u>

On a planning basis, FBC's CPA entitlements, as well as entitlements contracted to FBC under the BPPA, BRX, and WAX line items in Table 5-1, are all fixed energy and capacity entitlement values from the Canal Plant Agreement (CPA) for each month of each year. Therefore, FBC has a very high level of confidence of having access to the available energy and capacity values listed for FBC facilities as well as contracted entitlements, for the entire length of the CPA contract. In Table 5-1, FBC has taken into account the reductions due to expected maintenance and operating reserve requirements.

On an operational basis, however, the entitlement energy or capacity values could be reduced in any given hour or day as a result of planned or forced generation outages or deratings.

28.2 Is there variability in the supply of energy and capacity such that in some years there is more energy available and in others less? Please define the variability with a probability curve.

Response:

Please refer to the response to CEC IR1 28.1.

28.3 Please identify any redundancy in the supply that can respond to outages of certain facilities.

Response:

FBC's available energy and dependable capacity from the FBC CPA entitlements, BPPA, BRX, and WAX (net of RCA) are subject to generation outages at the corresponding facilities. FBC has several options to respond to outages, and replace lost power. On a short-term, operational basis, FBC can call on operating reserve to cover any power lost for the first 60 minutes of any outage. For any outages longer than 60 minutes in duration, FBC has the option of purchasing replacement power from the wholesale market, via its CEPSA contract with Powerex. FBC may also choose to reduce the amount of surplus WAX capacity that it sells to Powerex under the CEPSA, and retain that capacity for its own use. Furthermore, FBC can also increase its usage under the PPA contract with BC Hydro, as FBC is rarely using the full 200 MW of PPA capacity available, and has never used the full amount of energy available under the contract.

28.4 Please identify all of FBC's contingency options with respect to responding to the absence of some element of the supply shown above.

Response:

Please refer to the response to CEC IR1 28.3.

6. TRANSMISSION AND DISTRIBUTION SYSTEM

29. Reference: Exhibit B-2, Page 121

Table 6-1: Transmission Line Lengths by Region and Voltage Class (kilometres)

Region	63 kV	138 kV	160 kV	230 kV	Total
North Okanagan	0	120	0	114	234
South Okanagan	123	103	16	99	341
Kootenay	455	0	23	50	528
Boundary	83	0	103	0	186
Total	661	223	142	263	1,289

29.1 Please provide the loading information across a year for each of these lines, showing peak utilization and average utilization by month.

Response:

FBC is unable to provide a response to this question due to the significant amount of detailed work required. There are over 100 transmission lines in FBC's system and the flow on these lines depends on the system load and the generation dispatch (both FBC as well as provincial) which varies continuously throughout the year. Considering the significant amount of effort required to extract and analyze the required data, and given that the information has little value with respect to the review of the LTERP, FBC respectfully declines to provide the requested information.

29.2 Please provide the reliability statistics for each of these lines.

Response:

The table below provides the 2021 year-to-date reliability statistics:

Region	Latest Customer Count	Total Outages Reported	Total Customers Interrupted	Total Customer Hours Of Interruption	SAIFI	SAIDI
North Okanagan	76,747	0	0	0	0.00	0.00
South Okanagan	26,860	18	15,666	42,304	0.58	1.57
Kootenay	34,077	97	97,049	319,413	2.85	9.37
Boundary	6,398	2	1,500	8,097	0.23	1.27
Total	**144,082**	**117**	**114,215**	**369,814**		
Average					**0.79**	**2.57**

29.3 Please confirm that the meshed nature of the transmission lines is that there is N-1 capacity available to cover the outage of any single line without interruption because all lines are operational and upon a failure the remaining lines are designed to carry the load requirement.

Response:

FBC confirms that transmission lines which are meshed satisfy the N-1 planning criteria.

30. Reference: Exhibit B-2, Page 124

> As shown in Figure 6-1, the FBC system is connected to the following five major BC Hydro transmission stations:
>
> - Kootenay Canal Generating Station (at 63 kV and 230 kV);
> - Vaseux Lake Terminal Station (500 kV);
> - Vernon Terminal Station (230 kV;
> - Selkirk Substation (230 kV), and
> - Nelway Substation (230 kV).

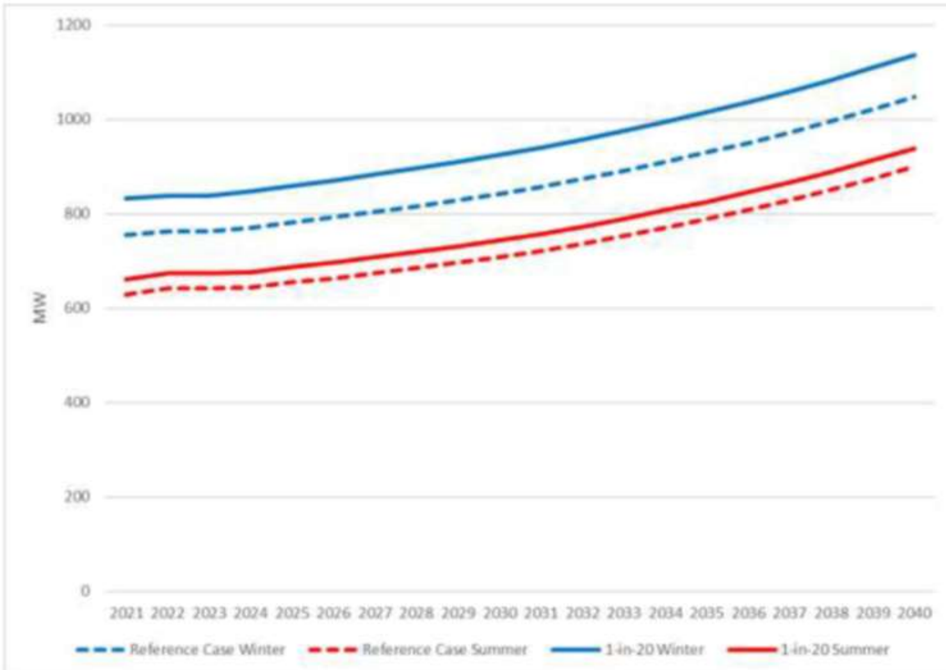
30.1 **FBC has described the importance of the BC Hydro connections for the reliable operation of its system. Please describe the reliability of the BC Hydro stations and the adequacy of those stations to meet the FBC requirements from time to time as needed.**

Response:

FBC's interconnections to the BC Hydro system have historically been a reliable source of power, and FBC considers them adequate to deliver FBC's energy and capacity entitlements, purchases, and wheeling requirements.

31. Reference: Exhibit B-2, Page 128

Figure 6-2: Reference Case vs. 1 in 20 Peak Demand Forecast



31.1 Please comment upon whether or not the FBC planning criterium for 1-in-20 year events may need to be reconsidered given that climate changes are creating more variability in the future related to weather event conditions, such that past experience may need to be changed for planning purposes.

Response:

Please refer to the responses to BCUC IR1 21.3 and 21.4.

32. Reference: Exhibit B-2, Page 130

Table 6-3: Transmission Reinforcement Projects

Time Frame	Project	Purpose	Primary Driver Capacity	Primary Driver Reliability
2021-2022	Kelowna Bulk Transformer Capacity Addition	Add additional 230/138 kV transformation capacity in Kelowna to adequately supply area load	×	×
2024-2025	Replace AS Mawdsley (ASM) Transformer T1	To provide adequate transformation capacity during normal and contingency conditions	×	×
2027-2028	52L & 53L Upgrade	To provide adequate capacity during single contingency	×	×
2028-2029	Replace AS Mawdsley (ASM) Transformer T2	To provide adequate transformation capacity during normal and contingency conditions	×	×
2028-2029	60L & 51L Upgrade	To provide required capacity when either LEE T3, T4 or T5 is out of service and there is an outage of another LEE transformer		×
2028-2029	20L Upgrade	To provide adequate capacity during normal and single contingency conditions	×	×

32.1 Please discuss the specific levels of utilization of existing capacities and the planning criteria that lead to reinforcement projects.

Response:

Please refer to the response to BCUC IR1 22.1.

32.2 Are all of the above projects being caused by growth on the system, which would bring parts of the system into conditions where at peak requirements the system components could not handle their N-1 capability response and therefore need reinforcement or some of these requirements cause by equipment not capable of operation at capacity as a consequence of aging or progressive failure of equipment or components? Please explain.

Response:

Please refer to the response to the BCUC IR1 22.1.

33. Reference: Exhibit B-2, Page 132 & 133

> If DG uptake increases significantly in the future, FBC transmission and distribution planners will need to have the tools and knowledge for planning and modeling a high-penetration of solar PV, alone or paired with batteries, or other DG technology into the system. Alternative engineering designs, technology solutions, and new and updated planning and operations practices that have been implemented in other jurisdictions may be needed for the FBC transmission and distribution system of the future.

> There have been increasing numbers of DG interconnections over the past few years, although the growth rate has slowed since 2018 (see Figure 2-9 in Section 2.3.4). Recent studies predict further cost declines in solar PV and associated increases in solar PV penetration rates. Additionally, provincial or federal incentives and/or federal tax credits, *CEA* or RPS legislation or feed-in tariffs for the purchase of renewable generating capacity from small facilities could make solar PV more cost-effective for customers. Further study of solar PV, and its pairing with battery storage, will be required to ensure that potential system impacts and necessary mitigation are understood and addressed in the FBC system.

33.1 Given the planning likelihood that the solar PV or other forms of solar energy are expected to increase significantly as the technology develops meaningful cost competitiveness, please describe whether FBC has currently planned to complete all relevant steps to ensure that its system is ready to take on the expected potential issues.

33.1.1 If so, what is the expected or planned cost of all the required studies to ensure FBC is adequately prepared?

<u>Response:</u>

Please refer to the response to BCUC IR1 23.1.

34. Reference: Exhibit B-2, Page 133

> The peak demand imposed by an EV on the grid depends on the size of the on-board battery, the owners' driving patterns, the charging strategy and the charger characteristics. With improvements in battery efficiency and longer ranges on an increasing number of EV models, customers will require higher electricity demand than that imposed by charging through a conventional 120 V (level 1) outlet. Several electric vehicles on one residential street could overload the local distribution transformer unless demand management measures are implemented to enforce load diversity and prevent a possible overload.

34.1 Please explain the full amount of project studies and actions which will be needed to protect the FBC system from unwanted consequences of certain levels of EV demand and the mitigating actions needed to control adequately to prevent predictable problems from occurring, and provide the costs for all of these required actions so that the long-term planning will enable FBC to contribute to the transformation of the vehicle transportation sector to renewable energy fuels.

Response:

At a high level, the forecast peak demand due to EV charging is included in FBC's annual Power Flow and Transient Stability Analysis Report. This report identifies a list of transmission projects that are required to maintain reliable service.

At this time, FBC has not yet defined the studies, actions or projects to address the impact of EV charging load on distribution infrastructure. If increases to distribution growth capital spending are required due to EV charging load, this will be described in future rate applications.

As discussed in Section 2.3.7.5, FBC is undertaking a residential demand response pilot that includes load shifting of key end uses including participants' EV chargers. Additionally, FBC will continue to monitor other opportunities for EV programs. The costs relating to any future programs in this regard have not yet been determined and will be included in future DSM Plan filings.

35. Reference: Exhibit B-2, Page 137 & 138

Table 6-5: Planned Projects (1-in-20 Peak Demand Forecast by 2040)

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

Table 6-6: Additional Projects Required to meet 550 MW Peak Demand by 2040 ($ millions)

Project	Cost ($millions)
New Distribution Stations	60
New Distribution feeders	40
Meshing Kelowna 138 kV Transmission System	20
138kV Transmission Line Re-conductor	40
138kV Transmission Line Addition	30
Ashton Creek to Vaseux Lake (ACK-VAS) 500 kV Transmission Line	500
DG Bell Second 230/138 kV Transformer Addition	20
Total	710

35.1 Please confirm or otherwise explain that, because the scenarios are loosely defined and have no causes, the Kelowna planning exercise and the subsequent project list and $840 million investment are largely speculative and will need to await a more specific understanding of the causes and where they will have an impact before mitigations measures can properly be planned to deal with the unfolding future.

Response:

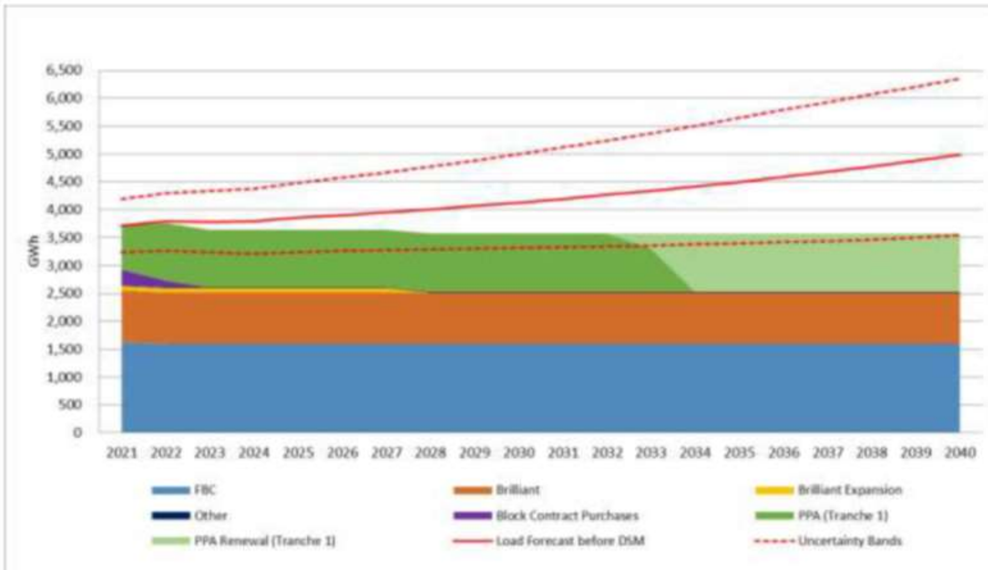
Not confirmed. The projects identified in Table 6-5 (which total $128 million) are the Kelowna area projects that FBC is currently planning to implement, based on the 1 in 20 system peak forecast, by 2040.

Table 6-6 includes additional projects totaling approximately $710 million that would be required to meet the peak demand requirements of the Kelowna area at the 550 MW peak demand level. This 550 MW peak demand level is reached under a number of load scenarios. The load scenario exercise provided in Section 6.5.4 was intended to explore, at a high-level, the potential projects required for the Kelowna area if certain load scenarios were to occur in the future. The load scenarios do have "causes" which are defined as the various load drivers in Section 4. FBC agrees that more information on the specific load drivers in terms of their impacts on peak demand and where on the system their impacts may occur is required to properly plan for mitigating measures such as those discussed in Section 6.5.4.4.

7. LOAD-RESOURCE BALANCE

36. Reference: Exhibit B-2, Page 143

Figure 7-1: Annual Energy Load-Resource Balance (GWh)

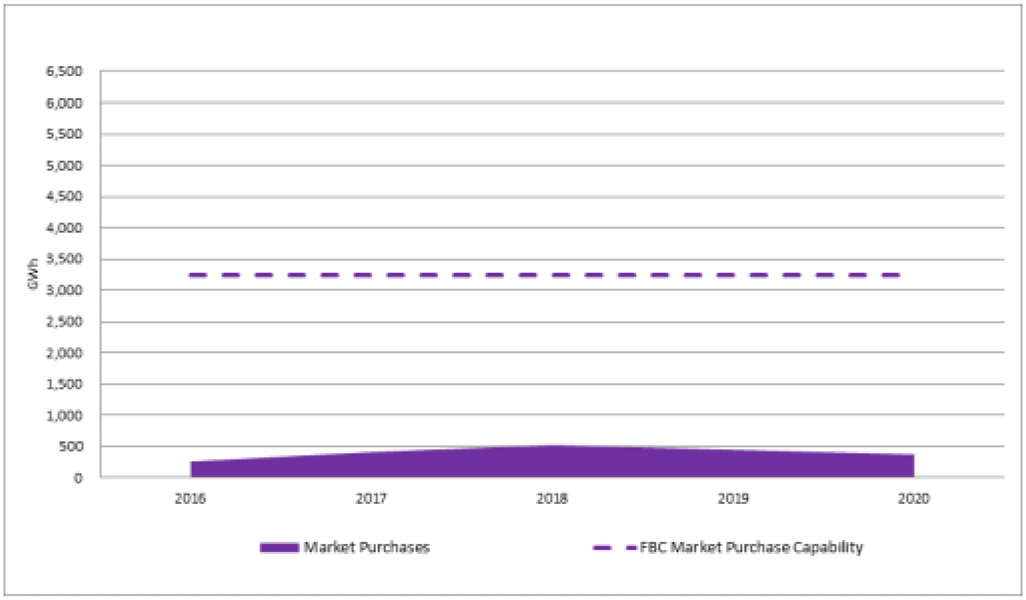


36.1 Please provide the market purchase capability graphically (and with the data) throughout the year, which FBC has been able to access in the past and provide the market availability for purchases in regard to the FBC capability to purchase.

<u>Response:</u>

Please refer to the response to BCUC IR1 1.5 for FBC's historical reliance on market purchases from 2016 to 2020. The referenced data, as well as the FBC capability to purchase, is provided in the figure below. The market availability for annual energy purchases is 3,241 GWh as per Table 10-1 of the Application.

Note that FBC cannot currently purchase 3,241 GWh annually from the market due to the following non-exhaustive list of reasons: commitments to existing supply-side resources, contractual limitations, and insufficient customer load.



36.2 Please provide the transmission line capabilities graphically (and with the data) throughout the year upon which FBC would rely for its market purchases and provide the quantitative capabilities for the transmission system to bring purchase to FBC's system.

Response:

Please refer to the response to CEC IR1 36.1. The transmission capability of 71 Line is the limiting factor for purchasing up to 3,241 GWh.

36.3 Please provide the potential purchase capability FBC may have to acquire energy from BC based independent power producers and the transmission capabilities for FBC to bring that power to FBC's system, graphically throughout the year (and with the data).

Response:

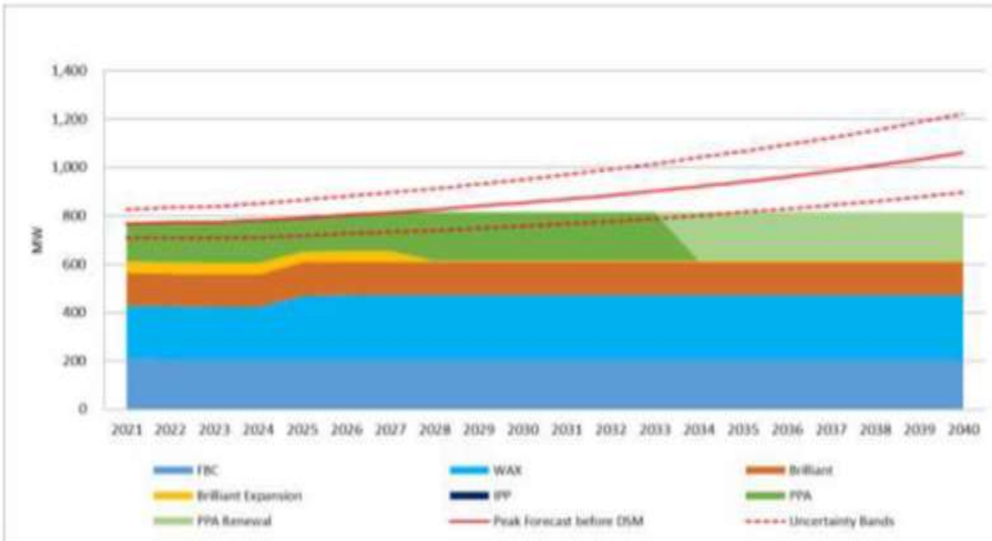
FBC has not modelled the potential purchase or transmission capability for acquiring energy from BC-based independent power producers (IPPs). FBC has no information on which IPP projects will be renewed by BC Hydro; however, please refer to the response to BCOAPO IR1 44.1 for which BC Hydro EPAs are expiring within FBC's service area. For the facilities listed in BCOAPO

IR1 44.1, FBC would likely not require additional transmission capability to transfer the power within FBC's service area.

As discussed in Section 10.6 of the Application, FBC will continue to monitor the BC Hydro contract renewals for any resource option opportunities, as well as remain open to other IPP projects, and will model the purchase or transmission capabilities at that time, as required.

37. Reference: Exhibit B-2, Page 145

Figure 7-2: Winter Capacity Load-Resource Balance (MW)



37.1 Please provide the transmission capability for FBC to access capacity from market sources in the US and specific purchase sources potentially in BC, graphically throughout the time period (and with the data).

<u>Response:</u>

Please refer to the response to CEC IR1 36.1. The transmission capability of 71 Line is the limiting factor for accessing the market within the US or within BC and purchasing up to 3,241 GWh.

38. Reference: Exhibit B-2, Page 147

Table 7-1: Load-Resource Balance Gaps

	First Year of Gap	2040 Gap With PPA Renewal	2040 Gap Without PPA Renewal
Annual Energy (GWh)	2023	1,410	2,450
Winter Capacity (MW)	2028	245	445
Summer Capacity (MW)	2028	240	440
June Capacity (MW)	2021	280	480

38.1 Please provide the capacity solutions (other than DSM) that FBC has been using to fill the June Capacity Gap for 2021 and describe the FBC experience in filling this gap.

Response:

In order to meet the June 2021 peak load of 764 MW, which occurred during the heat dome event, FBC used capacity resources as outlined in the table below. Please note that FBC does not have any available WAX capacity during the month of June, as the entire amount is allocated to the RCA.

FBC Existing Resources	Capacity (MW)
FBC CPA Entitlements	175
BPPA	115
BRX	35
PPA Capacity	200
Market	265
WAX (net of RCA)	0
Total	790

During June 2021, FBC surpassed its previous winter peak demand of 746 MW, which occurred on December 20, 2008. While there were indications that hot weather and therefore high demand would hit the region, the temperatures and power use far exceeded expectations[6] and operational load forecasts. FBC used the entire 200 MW available under the PPA contract, both to ensure security of supply and also to mitigate high wholesale market prices in the region which reached $334 per MWh (US dollars). Furthermore, FBC required an additional 265 MW from the wholesale market to meet peak demand. FBC was able to access this supply through the CEPSA contract with Powerex. FBC likely would not have been able to obtain the necessary market supply without

[6] This was true for other utilities in the region as well, as described in the following article: https://www.spokesman.com/stories/2021/jul/03/some-washington-utilities-saw-all-time-usage-highs/

a close contractual relationship with a well established marketer such as Powerex given the very tight supply in the region.

38.2 Please provide a discussion of the full capability FBC would need to have in order to fill this gap in the event that contingency requirements were necessary because of a failure of any particular source of capacity needed.

Response:

In the response to CEC IR1 38.1, FBC provided a list of FBC's resources and the corresponding capacity (in MW) that FBC used to meet its capacity needs in June 2021. During that period, FBC's available capacity exceeded the load level during the heat dome event. Although there can be no "planning" for such an unprecedented event, this illustrates the depth and flexibility of FBC's capability to meet unplanned load on an operational basis.

The magnitude of the load was itself a severe contingency requirement. If further resource contingency events had occurred (such as FBC generator outages), FBC would have been able to call on Operating Reserve for 60 minutes. After that, even higher market purchases would have been required, if available. If the market resources were unavailable, then there would have been no other recourse but to exercise the Imbalance Agreement with BC Hydro, which allows FBC to rely on BC Hydro supply on an emergency basis.[7] If that had also been insufficient due to BC Hydro's inability to provide the needed capacity, then FBC would have had no choice but to manually curtail load.

The largest capacity resource used to meet the June 2021 heat dome event was market supply of 265 MW. Of this, 239 MW was required to meet load.[8] Therefore, if the market had been unavailable, 239 MW of additional generation resources within FBC's service area would have been required to meet the peak load demands.

[7] The Imbalance Agreement allows FBC access to additional BC Hydro capacity in the event of an emergency. However, FBC is contractually prevented from relying on this as part of its planning process.

[8] In reality, under the CPA, the full 265 MW of market imports was used to meet load, and FBC generation resources were backed down by 26 MW to balance the system. This system margin of 26 MW would have been available if loads had been even higher. As the load level is not known ahead of time, it is prudent to purchase more than is expected to be needed and FBC always attempts to have a reasonable surplus positive margin in every hour on an operational basis.

8. RESOURCE OPTIONS – DSM

39. Reference: Exhibit B-2, Page 149

> The DSM program scenarios FBC considered are based on incenting ever larger proportions of the DSM measures' incremental costs. The same DSM measures were included in all scenarios, and the uptake was based on the market potential. This approach supplants the prior metric of expressing DSM savings targets as a percent of load growth offset. That metric, which originated in the 2007 BC Energy Plan, included targets only to the end of 2020. New load growth forecasts are significantly impacted by electric vehicle growth, which DSM has no energy savings measures thus the existing approach was abandoned in favour of one that aligns with incremental costing, similar to other utility conservation potential reviews, including FEI.

39.1 Please discuss why FBC treats the EV market growth to have no energy savings DSM options.

Response:

FBC is not aware of any market-ready technologies that reduces the amount of electrical energy needed to charge an EV. DSM interventions to address EV loads involve shifting the charging period of the EV to non-peak times, however, that shifting does not result in energy savings.

39.2 Please describe FBC's view of encouraging EV drivers to share rides, to reduce the distance they need to drive to various activities (work, school, shopping, entertainment etc.) by locating closer to those activities or by going to those activities less frequently and why these would not be DSM program-worthy.

Response:

To date, FBC has not evaluated the potential effectiveness of behavioural change programs or other incentives to encourage EV operators to change behaviours beyond how they charge their EVs. FBC may consider including EV ride sharing messaging as part of future conservation education and outreach activities.

39.3 Please describe FBC's view of adopting alternate shared transit options for some transportation activities.

Response:

In general, FBC supports shared transportation approaches, and has previously worked with Modo and the City of Kelowna to support shared mobility resources. However, FBC has not specifically evaluated the adoption of alternative shared transit options as a specific DSM measure.

39.4 Please discuss the EV market in terms of hybrid electric vehicles with the ability to fuel switch not as a DSM option but as a means to avoid electricity pricing incentives arranged to lessen demand in a particular period.

Response:

FBC is not relying on, nor planning to incent, the adoption of plug-in hybrid vehicles as a means of reducing peak period demand or avoiding time-based rates. FBC expects that some customers will choose plug-in hybrid vehicles (while they are permitted to be sold) for a variety of reasons.

It is not clear that plug-in hybrid vehicles would significantly reduce on-peak demand in any case since these vehicles can charge at the same rate as full battery electric vehicles on Level 2 chargers (albeit for shorter duration, on average).

Self-charging, or non-plug-in, hybrids do not require charging and thus have no impact to the load requirements of the electric utility.

39.5 Please discuss the relative efficiency of hybrid electric vehicles versus standard ICE vehicles and their capability to reduce GHG emissions significantly without impacting the FBC energy and or capacity gaps.

Response:

Although FBC does not have specific data regarding the relative efficiency of hybrid compared to ICE vehicles, Natural Resources Canada notes that a typical non plug-in hybrid offers fuel savings and CO_2 reductions of 20 to 40 percent compared to gasoline-only vehicles.[9] Plug-in hybrids offer further potential for increased fuel savings and GHG reductions; however, the cost differential

[9] https://www.nrcan.gc.ca/sites/nrcan/files/oee/pdf/transportation/tools/fuelratings/2021 Fuel Consumption Guide.pdf

between conventional gasoline and electricity will likely incent customers to use electricity whenever possible.

39.6 Please comment on whether or not the increasing use of electric bicycles, motorcycles, and golf carts will impact FBC's energy requirements, if at all.

Response:

FBC expects the impact of the load requirements associated with these types of transportation to be immaterial to the load forecast for the foreseeable future.

39.7 Please provide quantification of the potential electricity savings for switching from an EV automobile to simpler electric modes of transportation. Please provide electricity use per km for electric bicycles and motorcycles and golf carts and compare these uses to EV automobile electricity requirements.

Response:

Electric bicycles use approximately twenty times less energy than a standard EV passenger vehicle, while electric motorcycles use approximately five to ten times less. FBC does not have specific information regarding the efficiency of golf carts relative to EV passenger vehicles; however, it is important to note that golf carts are not permitted on provincial highways under the *Motor Vehicle Act Regulations* and would likely be of very limited applicability in terms of displacing conventional passenger vehicles.[10]

[10] https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/26_58_07

40. Reference: Exhibit B-2, Page 151

Table 8-1: Key DSM Scenario Data

Category	DSM Scenario				
	Low	Base	Med	High	Max
Energy Savings, GWh					
Average per annum ('21 - '40)	21.0	21.8	22.4	23.4	25.2
Average per annum ('21 - '29)	26.8	28.0	29.4	31.4	34.5
Total (2021 to 2040)	421	435	449	468	503

Category	DSM Scenario				
	Low	Base	Med	High	Max
Capacity Savings, MW					
Total (2021 to 2040)	61.6	64.0	65.6	68.1	72.7
Resource Cost, 2020 ($000s)					
Average Cost ($/MWh)	$38	$44	$49	$57	$75
Incremental cost compared to base case ($/MWh)	N/A	-	$183	$190	$234

40.1 Please confirm whether or not the incremental cost compared to base case ($/MWh) is FBC's incremental cost for the last KWh of DSM measures savings or a comparison to alternative incremental costs for providing the energy and capacity.

<u>Response:</u>

The value represents a comparison to alternative incremental costs for providing the energy. The incremental cost compared to the base case (in $/MWh) looks at the additional (i.e., incremental) costs of each of the Med, High, and Max DSM scenarios compared to the Base scenario. It is calculated by the following formula:

$$\textit{Incremental cost compared to base case} = \frac{\textit{Total Cost of DSM Scenario} - \textit{Total Cost of Base Scenario}}{\textit{Total Savings of DSM Scenario} - \textit{Total Savings of Base Scenario}}$$

This should not be considered the same as a last-kWh approach to comparing the DSM Scenarios. In addition, the calculation does not consider differences in capacity savings between the scenarios.

40.2 For the DSM average resource cost, please provide the cost benefit ratio for the DSM.

Response:

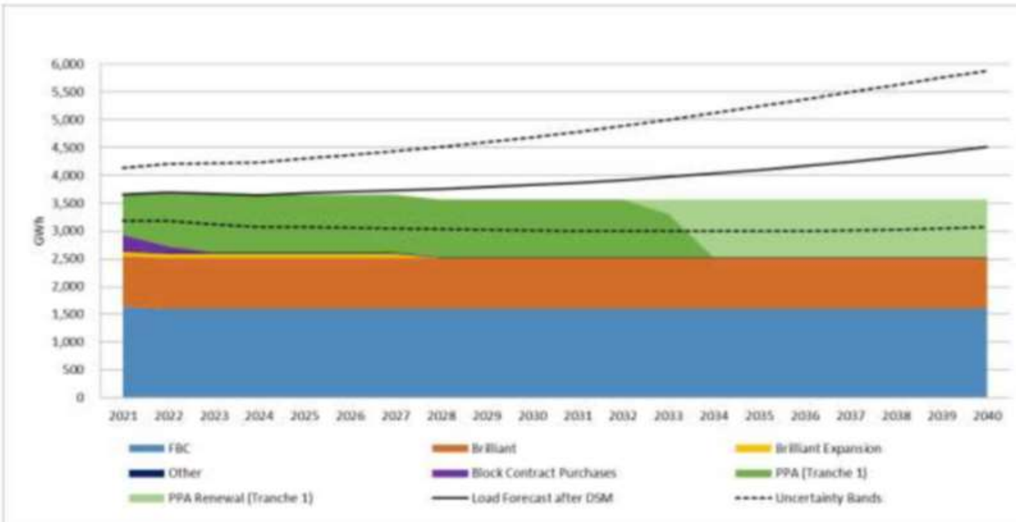
FBC interprets "cost benefit ratio" as referring to the Total Resource Cost test. The Total Resource Cost test for each DSM Scenario (each having a different average resource cost), is shown in the following table.

	DSM Scenario				
	Low	Base	Med	High	Max
Total Resource Cost Test	1.9	1.9	1.8	1.8	1.7

9. LOAD-RESOURCE BALANCE AFTER DSM

41. Reference: Exhibit B-2, Page 154

Figure 9-1: Energy Load-Resource Balance after DSM



41.1 Please provide an Energy Load Resource Balance ("E-LRB") graphically as in Figure 9-1 for each of the alternative DSM options with higher incentives.

<u>Response:</u>

The figures below provide the energy LRB for each of the DSM scenarios with higher levels than the Base scenario.

Figure 1: Energy LRB for Medium DSM scenario

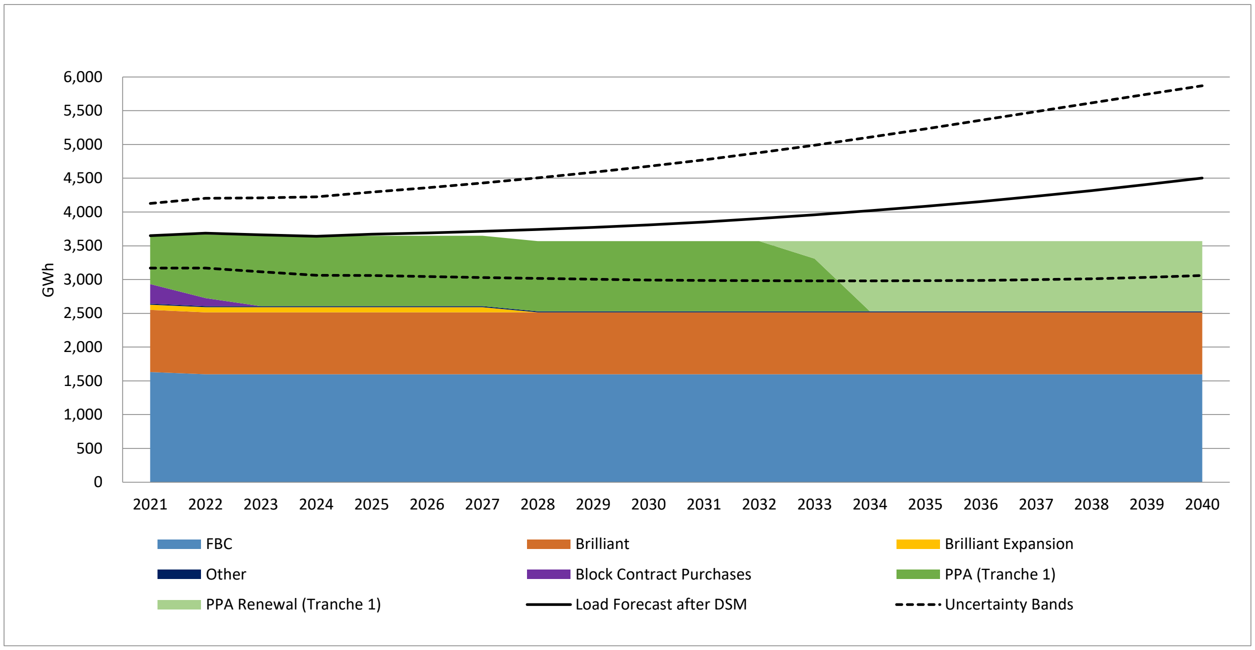
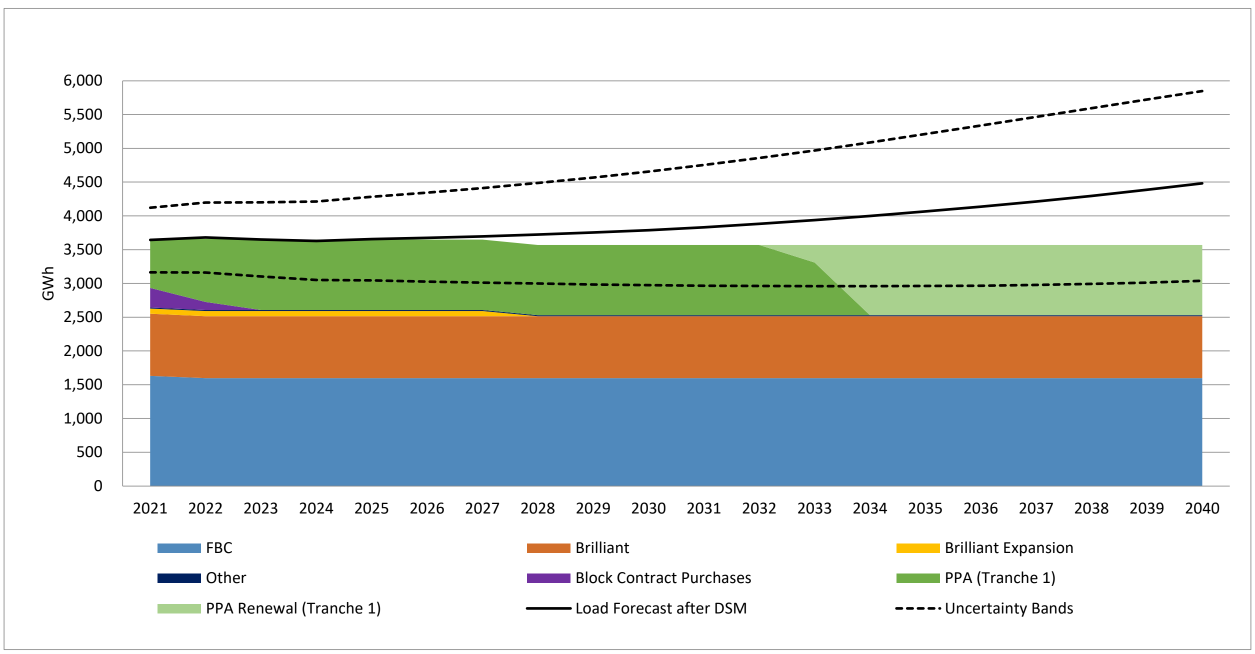
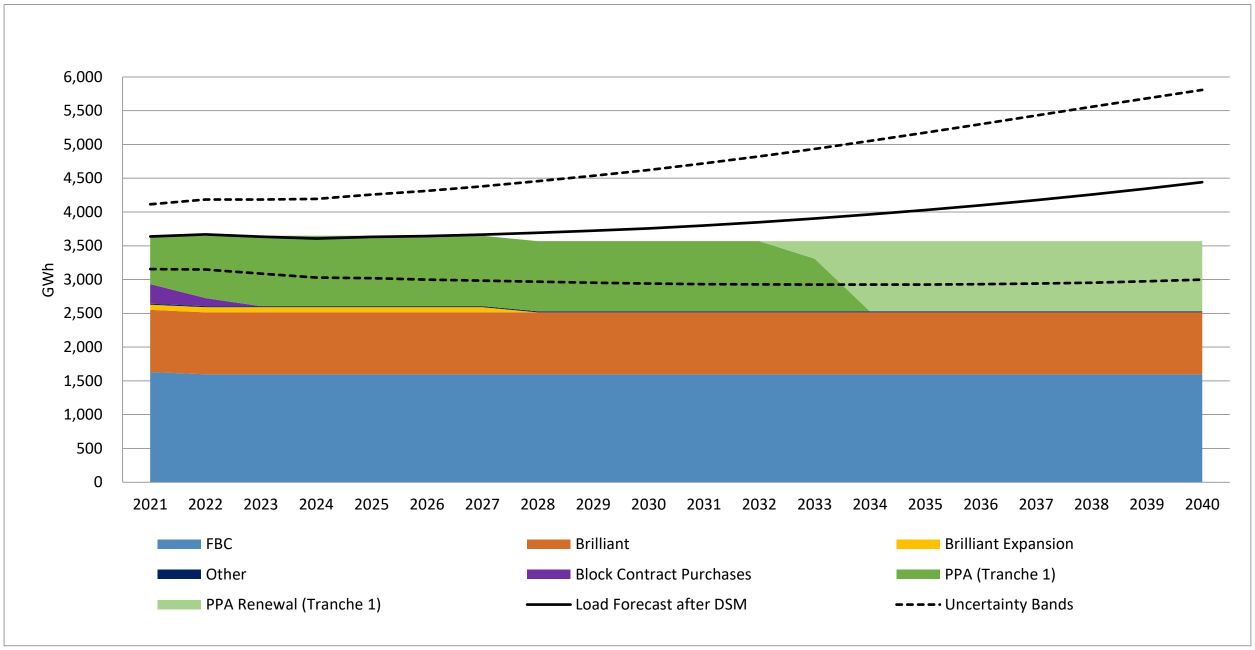


Figure 2: Energy LRB for High DSM scenario



1 **Figure 3: Energy LRB for Max DSM scenario**



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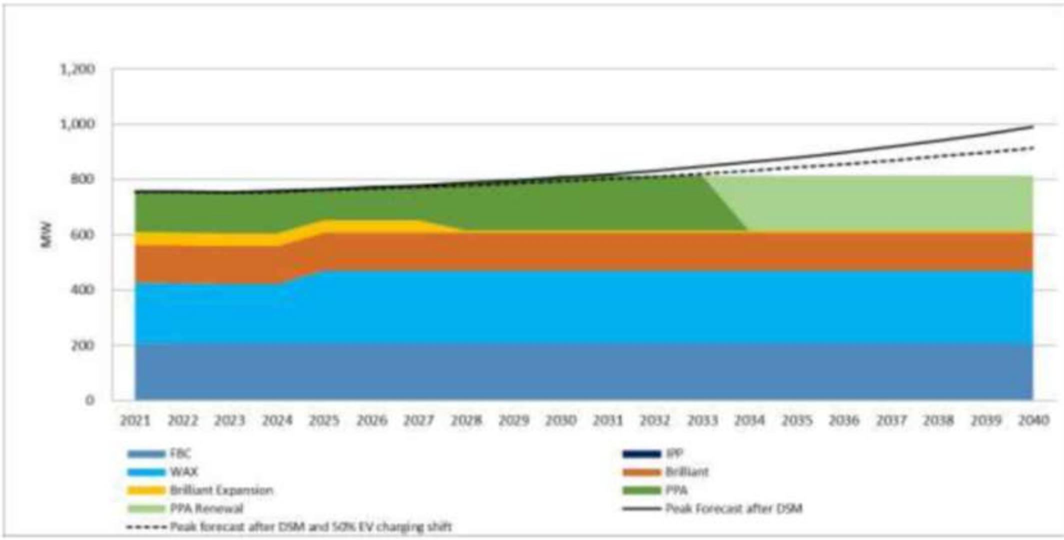
3

42. Reference: Exhibit B-2, Page 156

Figure 9-3: Winter Capacity Load-Resource Balance after DSM and EV Charging Shifting

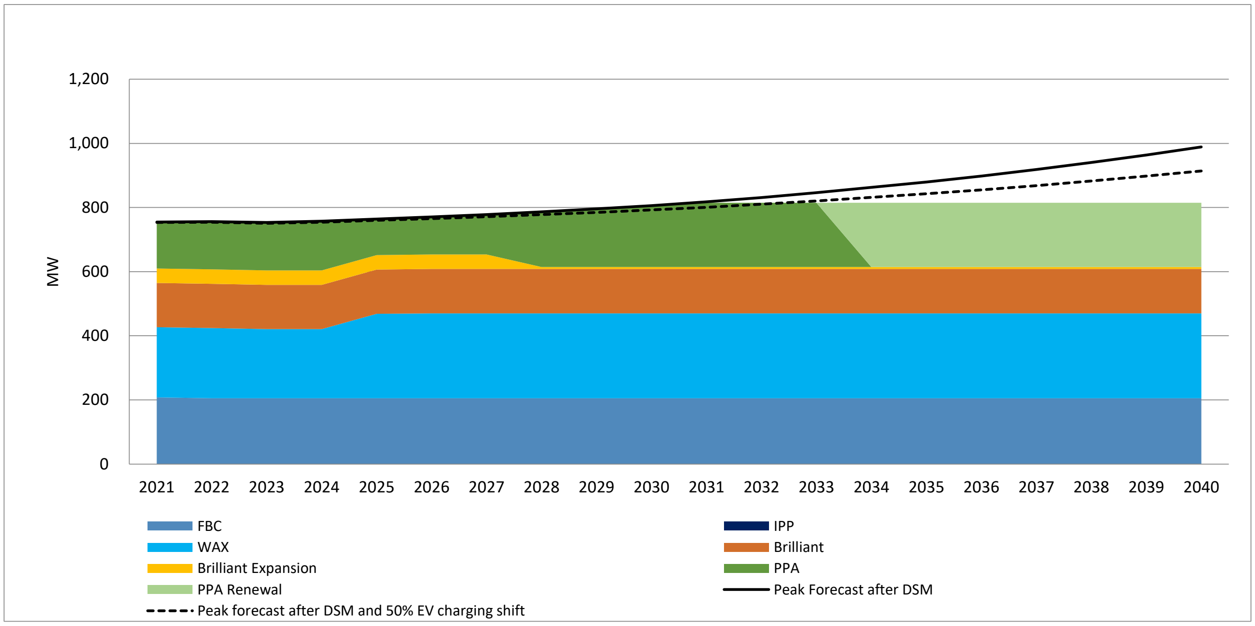


42.1 Please provide the Capacity Load Resource Balance ("C-LRB") graphically as in Figure 9-3 for each of the alternative DSM options with higher incentives and including options placeholders for demand response options not in the other DSM options.

<u>Response:</u>

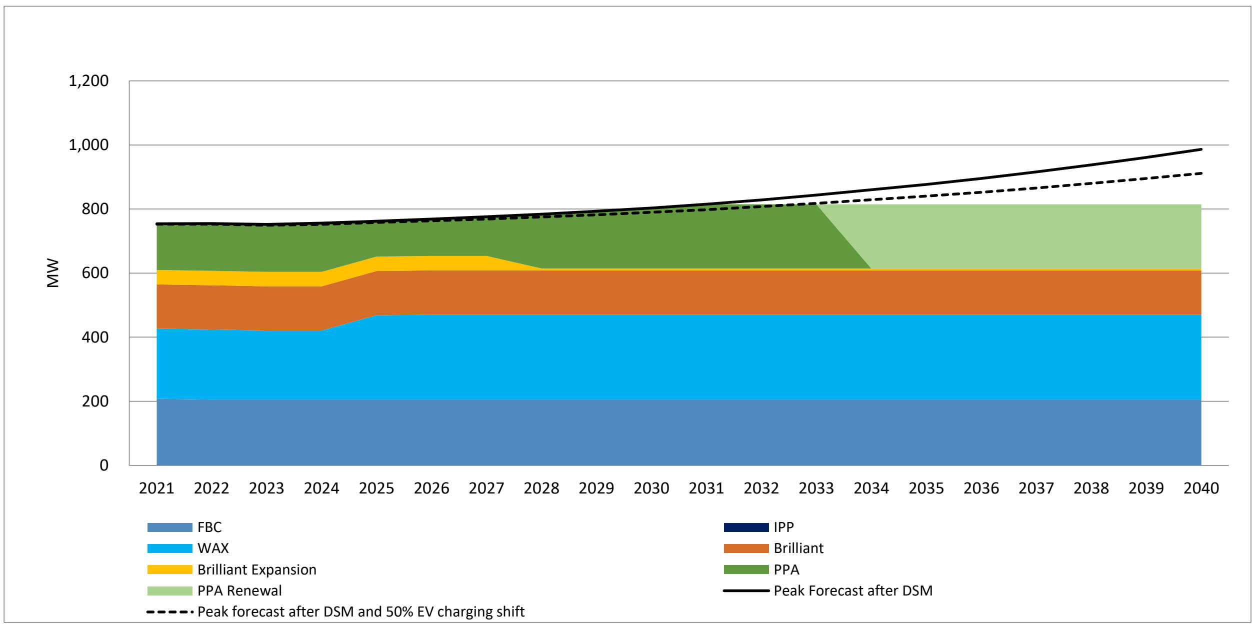
The figures below provide the winter capacity LRB for each of the DSM scenarios with higher levels than the Base scenario. The figures also include the peak forecast after DSM and a shift in EV charging of 50 percent (as assumed in Figure 9-3).

1 **Figure 1: Capacity LRB for Medium DSM scenario**



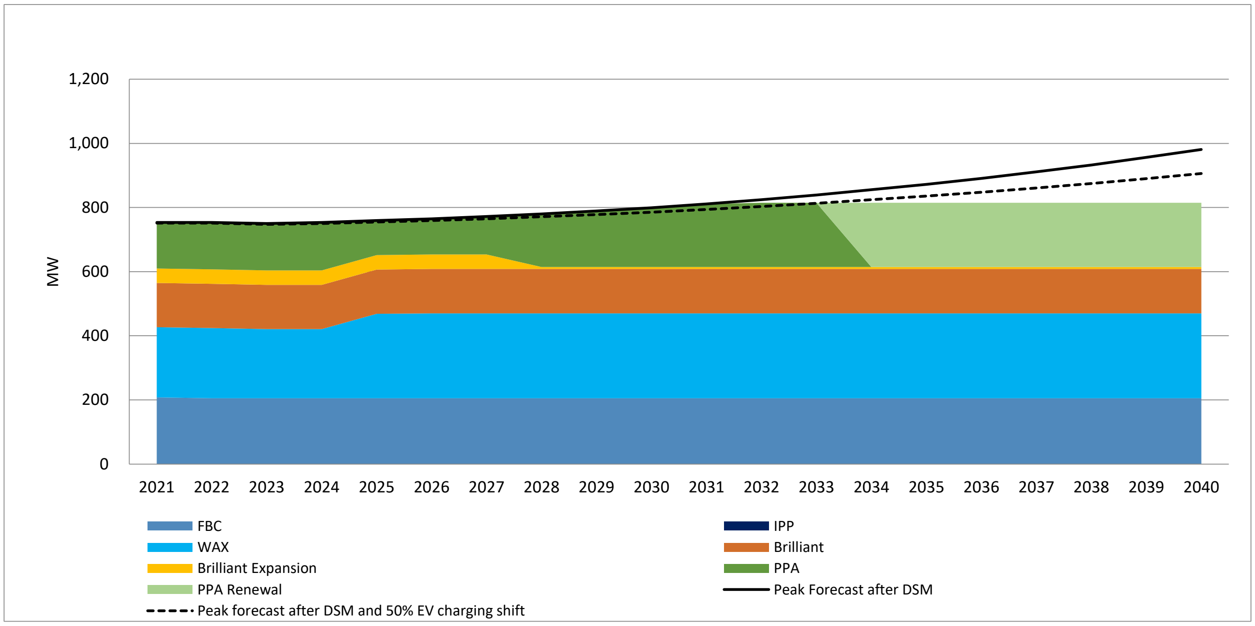
2

3 **Figure 2: Capacity LRB for High DSM scenario**



4

Figure 3: Capacity LRB for Max DSM scenario



43. Reference: Exhibit B-2, Page 160

> The proposed base level of DSM offset discussed above, and in Section 3 of the LT DSM Plan, satisfies the requirement to provide cost-effective DSM. The average cost of the proposed DSM level is $38 per MWh, which is well below the DSM cost-effectiveness threshold LRMC of approximately $90 per MWh. However, higher DSM scenarios were not chosen for the following reasons, as discussed in Section 8.1 and Section 3 of the LT DSM Plan:
>
> - They are less cost-effective than other resource options. FBC would be paying an increased incremental incentive proportion of measure costs, especially in comparison to the relatively low cost of power supply options, such as market electricity purchases. This is discussed in Section 11.3.1, which shows that the LRMC values for the portfolios with the higher DSM levels are higher than for the portfolio with the proposed level of DSM; and
> - They present higher risks of insufficient customer participation. DSM participation is voluntary and FBC cannot have assurance that customer participation will be sufficient to meet the higher scenarios. The fact that FBC had below target energy savings in recent program results indicates that it may not be readily feasible to achieve higher levels of DSM.

43.1 Please discuss whether or not for many DSM measures, once they are adopted, they can become a permanent part of the cost-efficient use of energy and capacity and can also move the markets to provide the more cost-efficient solutions permanently.

<u>Response:</u>

One of overarching goals of FBC DSM program design is to promote market transformation of energy efficient technologies. Once certain DSM measures have been in market for an extended period of time, their adoption may become widespread and the cost differential to the base case reduced enough that customers begin to adopt the technology on their own without the need for DSM programs and/or incentives.

FBC has experienced this market transformation trend with several past DSM measures it used to incent, such as high-efficiency fluorescent lighting and high-efficiency motors. These technologies now are considered base case technologies with respect to program design and DSM resource planning.

43.2 Please discuss the degree to which market purchases can be a permanent part of the FBC resource stack for the foreseeable future and discuss the potential for cost variability in the energy markets, should the over-supply in other jurisdictions diminish significantly.

Response:

FBC believes that market purchases can remain a part of FBC's energy resource stack for the foreseeable future based on current market outlooks and price forecasts. As discussed in Section 11.3.9, if the over-supply in other jurisdictions should diminish significantly, and market conditions change such that accessing market energy was no longer reliable and cost effective, then FBC would move to become energy self-sufficient in response to this.

10. SUPPLY-SIDE RESOURCE OPTIONS

44. Reference: Exhibit B-2, Page 162

> primarily evaluated for their capacity attributes. For this LTERP, FBC has included battery storage as a capacity resource option. While batteries can provide capacity during peak demand hours, the duration of the capacity provided is limited by the discharge capability of the batteries. FBC has included batteries with 4-hour discharge capability, after which time they must be re-charged before they can be discharged again. In this way, battery storage is similar

44.1 The CEC supports the FBC move to incorporate batteries as part of its planning because this option is evolving. Please provide a discussion with respect to FBC's reasons for including batteries.

Response:

FBC has included battery storage in its possible resource options because, as discussed in Section 3.2.3 of Appendix K – Resource Options Report, the cost of battery storage has declined significantly in recent years due to improvements in technology. As noted in Appendix D – PNW Electric Utilities Integrated Resource Plans Comparison Table, battery storage is among the preferred resource strategies for a number of regional utilities.

44.2 When considering battery options has FBC considered the charging and discharging cycling for integration of intermittent renewable supply sources, the likely duration of the battery capability, the expected service life of the battery, efficiency of the battery cycle energy in versus energy out, the future cost potential for additions of battery capability, whether or not having the battery capability storing energy during the day and servicing the evening peak or storing energy over the night time low period for use at daily peak times would make sense.

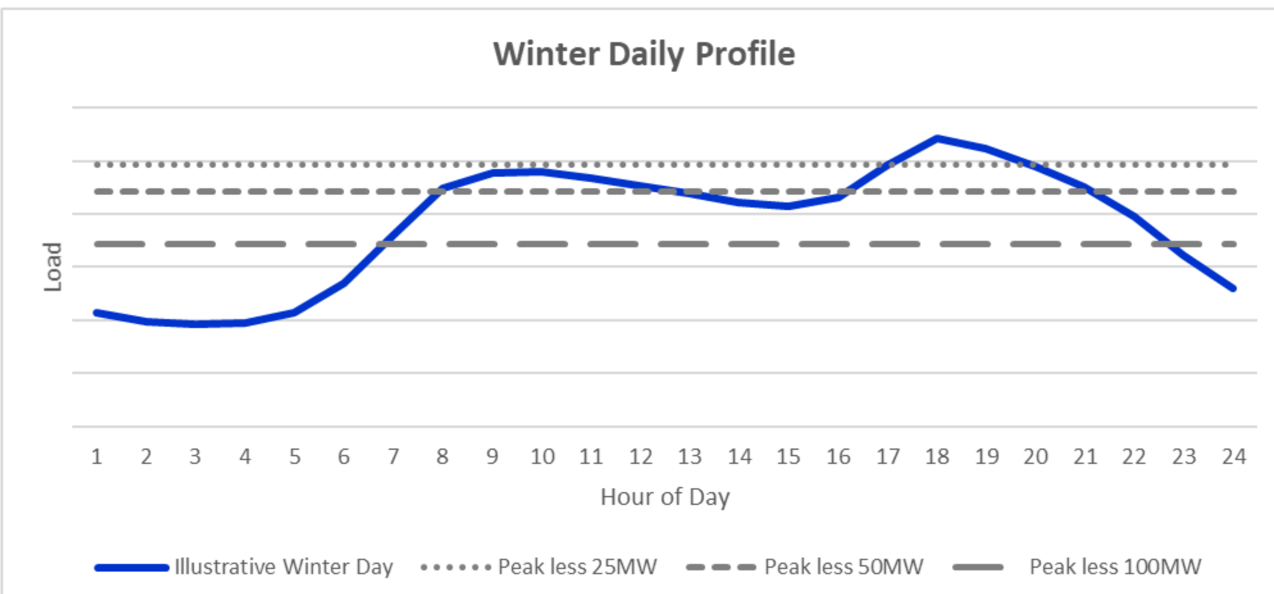
Response:

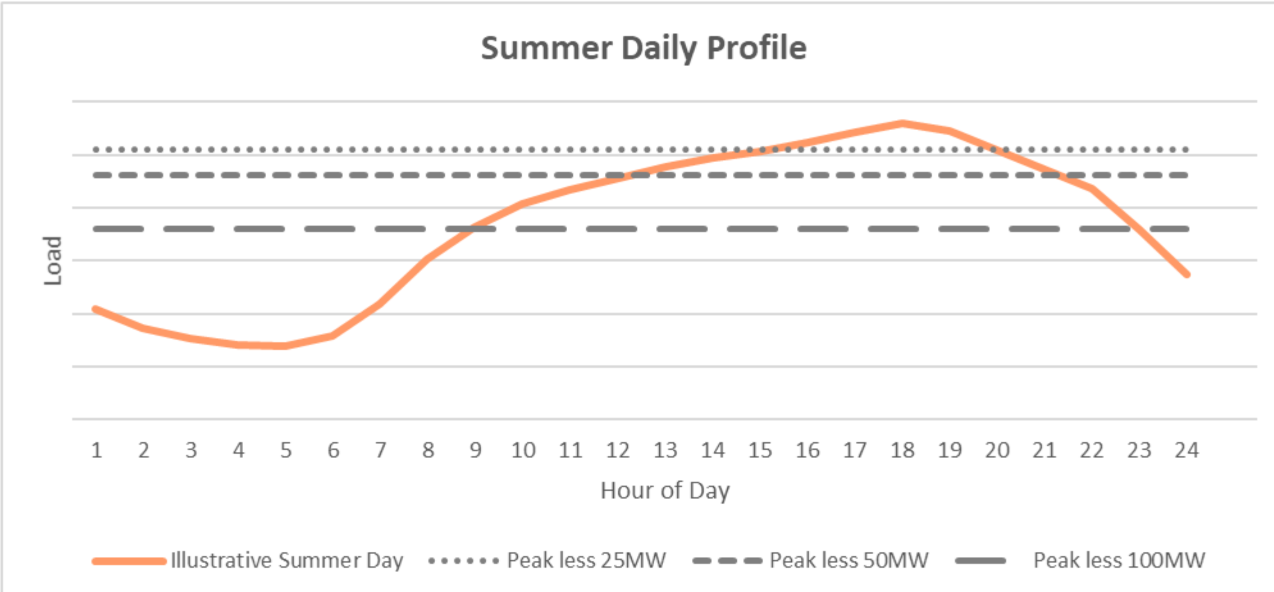
Within the portfolio model, a battery resource can be selected in combination with an intermittent resource. The battery resource options considered were assumed to be lithium ion with a 4-hour duration and an expected lifespan of 20 years. The battery resource options were assumed to be 90-percent roundtrip efficient, and therefore a net consumer of energy on a monthly basis. As shown in the response to CEC IR1 5.3, FBC has forecast a decline in battery costs over the planning horizon.

Modelling battery charging cycles is complex as the load is shifted from one period to another period within the same day (i.e., intraday load shifting), and potentially for multiple periods within the day other than just low load hours to high load hours, thereby changing the daily load shape.

FBC's resource planning models are primarily based on monthly peak capacity requirements, total monthly energy requirements, and the associated load duration curve for hourly requirements. Therefore, the models utilized are not sophisticated enough to represent intraday hourly interactions and any corresponding changes in daily load profiles as a result of selected resources. However, FBC did consider these issues outside of the model and considers the selected battery resource options are a good fit for the FBC system.

The following two diagrams illustrate generic FBC winter and summer daily profiles. The dotted lines represent 25 MW, 50 MW, and 100 MW less than the daily peak hour. The winter daily profile has a morning and an evening peak, while in comparison the summer daily profile has just an evening peak.





A 50 MW battery with 4 hours of storage duration can store approximately 200 MWh of energy. A 50 MW battery with 200 MWh of energy storage is also capable of providing a lower MW value over a longer period of time (i.e., 25 MW of dependable capacity for 8 hours).

As battery resources become an increasingly large portion of the capacity used to meet the daily load curve, then the duration of the battery becomes a concern. In both the winter and summer profiles, a 25 MW battery is able to mostly cover the four highest peak hours in the day as shown in the 100 and 98 percent entries, respectively, in the table below. In contrast, a 50 MW battery is not able to discharge the full 50 MW of installed capacity over the required longer duration. As a result, FBC derated the 50 MW battery in the model to 41 MW in the summer and 47 MW in the winter. This represents the battery being used at a lower output for more than 4 hours as needed to contribute to the peak hours. To support a load level of 100 MW less than the daily peak, in either the winter or summer months, the battery would need significantly more energy storage capabilities; FBC viewed this option as impractical at this time.

The following table shows the assumed portion of the capacity available during peak hours, expressed as a percentage of installed capacity, after accounting for energy storage limitations:

Battery Size & Characteristics	Summer Average Dependable Capacity (% of Installed Capacity)	Winter Average Dependable Capacity (% of Installed Capacity)
25 MW with 4 hour Duration (100 MWh of Energy Storage)	100% (25 MW * ~4.0hrs = 100 MWh)	98% (24.5 MW * ~4.1hrs = 100 MWh)
50 MW with 4 hours Duration (200 MWh of Energy Storage)	82% (41 MW * ~4.9hrs = 200 MWh)	94% (47 MW * ~4.3hr = 200 MWh)

If batteries and intermittent resources were to become a material portion of FBC's daily resources in the future, further detailed modelling is required in order to account for changes to the daily load profile in addition to the monthly energy and capacity requirements. Accounting for intraday interactions and changing daily load profiles materially increases the complexity of the current model beyond what is practical to achieve, and therefore requires a new modeling approach that would take significant time and resources to develop. However, by examining the necessary interactions outside of the model and selecting workable battery options, FBC believes the current model is sufficient at this time.

45. Reference: Exhibit B-2, Page 165

Table 10-1: Resource Options Type and Size Summary

Resource Option[179]	Portfolio Analysis Short Name	Type	Number of Plants in FBC Portfolio Analysis	Average Dependable Capacity (MW)	Annual Energy (GWh)
PPA Tranche 1 Energy	PPA	Baseload	N/A	N/A	Up to 1,041
PPA Tranche 2 Energy	PPA	Baseload	N/A	N/A	Up to 711
PPA Capacity	PPA	Baseload	N/A	Up to 200	N/A
Market Purchases	Market	Baseload	N/A	Up to 75	Up to 3,241
Wood-Based Biomass	Biomass	Baseload	3	9 – 30	73-237
Geothermal	Geothermal	Baseload	4	15 – 75	130 - 657
Gas-Fired Generation (CCGT)	CCGT	Baseload	3	67 – 279	528 – 2,201
Small hydro with storage	Hydro	Baseload	4	8 - 50	77 - 443
Gas-Fired Generation (SCGT) - NG	SCGT	Peaking	3	48 – 100	75 – 158
Gas-Fired Generation (SCGT) - RNG	RNG_SCGT	Peaking	3	48 - 100	75 - 158
Pumped Hydro Storage	PSH	Peaking	2	100 – 1,000	N/A
Onshore Wind[180]	Wind	Intermittent	13	21 – 133	196 – 1,239
Run-of-River Hydro	RoR	Intermittent	3	2 – 6	16 - 52
Utility Scale Solar	Solar	Intermittent	11	4 - 107	28 - 754
Distributed Solar[181]	DistSolar	Intermittent	3	0 - 2	2 - 15
Battery Storage[182]	Battery	Peaking	1	39	N/A
Distributed Battery Storage[183]	DistBattery	Peaking	1	24	N/A

45.1 Please discuss FBC's categorization of battery storage as limited to 1 for 39 MW and the limit to 3 RNG fired SCGTs at a potential 100 MW.

Response:

FBC limited the portfolio to 50 MW of battery storage in this LTERP, which represents between 6 to 7 percent of FBC's current peak load. BC Hydro has also suggested a similar cap ratio by limiting the amount of selectable batteries to 500 MW[11] or an estimated 5 percent of their peak load.[12] FBC considers this a reasonable maximum until it has greater experience with larger

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11 BC Hydro, TAC#7 Meeting Presentation, Slide 28 "Options that provide capacity –recap".

12 Assuming an approximate system peak of 10,000 MW.

penetrations of battery storage within the daily resources in addition to the relative size of the battery compared to FBC's current peak load. In contrast, RNG-fired SCGTs are not energy constrained in the same respects as a battery. If the SCGT unit is needed during an extreme cold or hot weather event, the RNG SCGT would not be energy constrained, assuming RNG fuel was available, and could run as long as necessary.

FBC limited the size of a gas peaking plant to a maximum of 100 MW, which represents between 13 to 14 percent of FBC's current peak load, but included two 100 MW units as resource options in addition to a 50 MW unit to give the optimization routine a combination of possible sizes. Alternatively, FBC could have included a larger 200 MW RNG SCGT unit, but on a practical operational basis, unit outages would represent 25 to 29 percent of the resources available to meet current peak load and would therefore create some reliability risk. There is also a reasonable limit to the amount of peaking resources that can be included in the portfolio as the deeper the peaking resources become in the resource stack the more often they are required to run.

46. Reference: Exhibit B-2, Page 166 & 167

Table 10-2: Supply-Side Resource Options Unit Cost Summary

Resource Option	UEC ($/MWh)	UCC ($kW-year)
Low DSM	$33	N/A
Base DSM	$38	N/A
Med DSM	$40	N/A
High DSM	$45	N/A
Max DSM	$58	N/A
PPA Tranche 1 Energy	$49 - $60	N/A
PPA Tranche 2 Energy	$80 - $95	N/A
PPA Capacity	N/A	$101 - $123
Market Purchases	$28 - $49	N/A
Wood-Based Biomass	$121 - $173	$682 - $719
Geothermal	$114 - $176	$863 - $1,377
Gas-Fired Generation (CCGT) - NG	$90 - $109	$150 - $287
Gas Fired Generation (SCGT) - NG	N/A	$131 - $148
Gas Fired Generation (SCGT) - RNG	N/A	$131 - $148
Small Hydro with Storage	$101 - $163	$687 - $1,271
Pumped Hydro Storage	N/A	$102 - $540
Onshore Wind	$68 - $91	$509 - $734
Run-of-River Hydro	$111 - $173	$817 - $1,330
Utility Scale Solar	$99 - $134	$686 - $863
Distributed Solar	$137 - $141	$829 - $882
Battery Storage	N/A	$267
Distributed Battery Storage	N/A	$226

46.1 Please comment on why FBC has shown market purchases as having no capacity.

Response:

FBC's position is that market supply cannot be relied on as a long-term capacity option,[13] and therefore, the UCC is listed as "N/A". Relying on market purchases for capacity in peak hours over the long term can be risky, which is discussed in Section 2.4.4 of the Application.

[13] Except for the month of June, where FBC has assumed 75MW of market access up to 2030 (as discussed in the response to BCUC IR1 1.3).

46.2 Please explain whether or not it is possible that FBC may be able to find capacity in the electricity markets when needed.

Response:

Since the CEPSA agreement with Powerex became effective on May 1, 2015, FBC has been able to purchase the required amounts of market power for capacity purposes when needed. However, this does not indicate the market is a risk-free source of capacity in the future as the market can be constrained at times, and likely more so in the future. For example, during the recent heat dome event in June 2021, market supply was extremely uncertain. The fact that Powerex found supply for FBC does not mean the market was robust, but rather it should be interpreted as FBC was fortunate. As the proportion of intermittent renewables increases in the market, the probability of FBC being as fortunate in similar future events is likely to decrease.

46.2.1 Does such capacity fill a capacity need in the same way as wind power, which has a potential to be providing capacity at a given time, but is intermittent and would need to have other statistically available supply to build up a degree of reliability for planning? Please explain.

Response:

FBC acknowledges that market energy in the future will be made up of more intermittent renewable resources. Other utilities are likely overbuilding renewable energy sources to increase the certainty that the needed dependable capacity will be available during peak hours. The remaining energy available for sale in the market from other utilities will depend on the circumstances in another utility's service area. It is possible that during extreme weather events both FBC and other utilities will be trying to meet their peak loads at the same time. A utility that builds a resource for purposes of meeting their own load during peak hours will depend on the output from their own resources first to meet their customers load, leaving less for sale in the market at the times of peak capacity need.

Portfolio C4 meets the capacity requirements over the planning horizon with a collection of renewable resources. Portfolio C4 contains solar, wind, and battery projects, similar to that proposed by the CEC in CEC IR1 50.1. The key distinction between the market risk and the risk of the utility's own intermittent resources is the utility's load is likely to be correlated with the weather, which is also likely correlated with the utility's renewable resources in or near their service area. For example, solar in the Okanagan is likely complementary with the air conditioning load in the Okanagan. The closer the alignment between the intermittent resources' output with the utility's load, the greater the confidence in the dependable capacity estimate. The available dependable capacity will vary by month. For example, solar in the Okanagan is not complementary with the after-dusk evening peak demand in the winter.

Lastly, the market is the primary contingency resource in the planning reserve margin model. With the CEPSA in place, FBC has greater confidence in market access to support unexpected conditions as supported by specific agreement clauses. To rely on the market as both a planned resource and a contingency resource is risky as a loss of market access (for example, via 71 Line) would result in two issues – no market to serve the load, plus no market to serve as a primary backup resource.

46.3 Please comment on whether or not for a gas fired generation SCGT – RNG the RNG could be purchased both before and after use of gas for capacity purposes to provide the GHG offsets required for this to be a clean source of capacity.

Response:

FBC has modelled the RNG SCGT units as taking RNG supplied by FEI under approved tariffs. FBC plans to purchase an equivalent amount of RNG for fuel for the SCGT plants. Plant details, such as the potential for on-site storage, have not been determined at this time.

46.4 Please discuss whether or not pumped storage and battery storage should be shown with a UEC ($/MWh) cost for the energy efficiency losses on the turnaround through the storage, and explain why FBC has not shown this important detail in the Table 10-2 comparisons.

Response:

Pumped hydro storage and battery resources do not generate energy, rather they alter the timing of when energy is delivered. FBC has modelled battery and pumped hydro storage as capacity resources able to support the monthly capacity requirements, while being a net consumer of energy on a monthly basis after accounting for the losses resulting from a round-trip efficiency less than 100 percent. As the overall energy contribution is negative in the portfolio, the resulting UEC value is also negative[14] and, as such, FBC has not included these values in the referenced

[14] Simplifying, UECs are the NPV of total costs divided by the total expected energy delivered over the expected life. If the resource consumes energy in the portfolio, the denominator becomes negative.

table. The UCC values reflect the costs of having capacity in a ready state to dispatch, which is the primary function of a battery and pumped hydro storage resources.

46.5 Please provide a technology assessment for the main viable options FBC would be considering: (a) SCGT – RNG; (b) Pumped storage; and (c) batteries, regarding their maturity and potential for cost reductions as the technology matures over time.

Response:

SCGT-RNG is the same technology as SCGT, except that it uses RNG as the fuel source rather than conventional natural gas. SCGT and pumped hydro storage are both mature technologies. Lithium ion battery systems are comparatively newer technology and costs are expected to decrease in real dollars. As shown in the response to CEC IR1 51.1, FBC has incorporated anticipated cost declines in battery storage technology as well as other technologies. There are also other battery technologies being commercialized, such as flow batteries. FBC does not have an opinion on which battery technology will dominate in the future.

47. Reference: Exhibit B-2, Page 167

> When looking at the unit costs in Table 10-2 above, it is important to remember that a resource option with the lowest unit cost may not be the best fit for FBC in terms of meeting customers' load requirements. For example, while pumped storage hydro has one of the lowest UCCs of about $102 per kW/year at the low end of the range due to economies of scale, the size of this resource option, with a capacity of 1,000 MW and no energy contribution, makes it an impractical option for FBC's current requirements. It would provide FBC with too much capacity, given the size of the Company's projected capacity gaps, and no energy. The portfolio analysis in Section 11 helps determine the optimal mix of resources based on cost and FBC's monthly energy and capacity requirements.

47.1 Please comment on whether or not FBC could establish the pumped storage option in cooperation with another utility that may need a firm capacity option so that the size is not a constraint.

Response:

FBC is open to all viable options that provide reliable, cost-effective, and environmentally responsible service to its customers. The value of a potential arrangement with another utility to share a pumped storage hydro resource would be dependent on many factors relating to the LTERP objectives, including, but not limited to:

- The output profile FBC would expect to receive from its share of the resource;
- The cost to FBC;
- The environmental footprint;
- Resiliency benefits to FBC's system; and
- Economic development opportunities.

47.2 Please comment on whether or not this option would and or could have both energy and capacity delivered at competitive prices when used in combination with market energy supply and/or intermittent renewable energy supply.

Response:

The cost effectiveness of this option would be project dependent and FBC has not completed detailed analysis for any of the pumped storage hydro resources at this time. Therefore, FBC is unable to determine if energy and capacity could be delivered at competitive prices using market energy supply and/or intermittent renewable energy supply.

48. Reference: Exhibit B-2, Page 170

> The levelized market prices in Table 10-2 and discussed above reflect the cost of market energy including a clean market adder. While market energy purchases have an associated carbon footprint, clean energy specified source contracts are available in the market. These contracts sell at a premium above regular market prices. As discussed in Section 2.5.7, FBC has applied a clean market adder of approximately $2 per MWh to the cost of its market purchases. Although FBC is currently comfortable with relying on market purchases for some of its energy needs, relying on market purchases for capacity in peak hours over the long term can be risky in terms of availability, as discussed in Section 2.4.4. There is also no guarantee that FBC will be able to access market capacity supply reliably, especially if there is no access to long-term firm transmission. FBC relies on Line 71 to access US market supply, and there can be transmission constraints both on Line 71 and on the US transmission south of the border that can interrupt that supply when FBC needs it for capacity purposes, as discussed in Section 5.5. Therefore, FBC does not believe that market supply can be relied on as a long-term capacity resource option.

48.1 Please comment upon whether or not the combination of batteries and market-supplied energy could be expected to provide capacity at times needed and do so cost-effectively, particularly as the technologies mature and the cost per unit of capacity declines significantly in the next 10 years.

<u>Response:</u>

Battery storage, in combination with market energy and intermittent renewables, is a component of FBC's preferred portfolios. As per the discussion in the responses to CEC IR1 44.2 and 45.1, FBC recognizes the potential for batteries to be part of a cost-effective portfolio. However, battery storage technology alone will likely not be the full solution to overcoming anticipated capacity shortfalls over the planning horizon.

11. PORTFOLIO ANALYSIS

49. Reference: Exhibit B-2, Page 174

> It is important to note that the portfolio analysis presented in this section provides a high-level indication of how load-resource balance gaps may be filled in the future. It is likely that before specific resource options are required, load forecasts, load-resource balances and resource options and costs will change. Based on the portfolio analysis results presented in this section, and assuming the reference case load forecast, proposed DSM level and continued market access, FBC will not require any new generation resources until at least 2030. If conditions arise in the future such that incremental generation resources are required sooner than expected, FBC expects that additional specific analysis regarding options will be performed and requests for approval will be brought forward in a separate application to the BCUC.

49.1 Because the lead times for some of the generation and capacity options may be significant, please discuss whether or not FBC anticipates being able to await the further development and cost competitiveness of some of the options FBC will likely be able to access in the future.

Response:

The timing of the decision to invest in incremental resources will be based on the load-resource balance requirements, reliability requirements, and policies that govern the resource portfolios, as opposed to the projected future cost competitiveness of resource options. Factors related to project development such as stakeholder and Indigenous consultation for new resources are also important considerations.

Material changes to FBC's load-resource balance can delay or accelerate the need for resources. For example, FBC's proposed EV charging mitigation program may help to delay the need for capacity resources further into the future. Conversely, in the event a new large load was to connect to FBC's system, the need for resources would likely be accelerated. FBC will continue to monitor various resource technologies available and, when additional resources are required, will consider the most cost-effective alternatives available that meet the LTERP objectives.

49.2 Please also discuss whether or not small pilot programs in the near future would benefit FBC's learning and ability to integrate various of the options in the future (obviously some of the options do not require nor would be amenable to small pilot programs).

Response:

If necessary and possible, FBC may propose small pilot projects to benefit FBC's learning and ability to integrate various resource options in the future, such as an EV charging demand management program. Any such project would need defined objectives and a method to measure the impact of the resource on the local area of the system.

FBC did propose a Community Solar Pilot Project in Kelowna, which could potentially be augmented with the addition of a complementary battery system. FBC has not undertaken any further analysis since the conclusion of the CPCN application in 2018[15], which was ultimately rejected, but it is reasonable to speculate that the economics of the solar project have changed since 2018 costing as well as the appetite for such a project among stakeholders.

[15] BCUC Order G-1-18.

50. Reference: Exhibit B-2, Page 175

Table 11-1: Portfolio Analysis Base Characteristics and Sensitivity Cases

Portfolio Base Characteristics	Sensitivity Cases
DSM Level • Proposed Base level	• No DSM (for DSM LRMC purposes) • Low DSM • Med DSM • High DSM • Max DSM
Reliance on Market Purchases • Capacity self-sufficiency starting in 2021 (except for June, which has a limit of 75 MW until 2030 and 0 MW thereafter) • No energy self-sufficiency	• Energy self-sufficiency by 2030 • No energy or capacity self-sufficiency • No clean adder for market energy • High market and carbon prices with no clean adder for market energy
Percent Clean or Renewable • Minimum 93 percent clean or renewable • Gas-fired generation permitted	• 100 percent clean or renewable including SCGT using RNG • 100 percent clean or renewable with no SCGT using RNG • High market and carbon prices • High clean resource option costs
Load Requirements • Reference Case load forecast	• Guidehouse load scenarios • Stakeholder average scenario

Portfolio Base Characteristics	Sensitivity Cases
EV charging shifting • No shifting from peak periods	• 25 percent shifting • 50 percent shifting • 75 percent shifting • 100 percent shifting
PPA Renewal • PPA renewed in 2033	• PPA not renewed, replaced with clean resources • PPA not renewed, replaced with clean resources and excluding SCGT using RNG • PPA renewed, high Tranche 1 pricing • PPA renewed, low Tranche 2 pricing

50.1 Please provide or comment on why it is not possible to provide a portfolio option with intermittent solar or wind supply from BC and/or market energy as a back-up, stored in batteries and with sensitivity for declining battery costs into the future (if FBC is willing to do this and needs specific battery attributes to consider, the CEC would appreciate being consulted to specify a potential future battery option).

<u>Response:</u>

Portfolio C4 generally reflects the characteristics being described in the question above. Portfolio C4 is capacity self-sufficient, yet still includes market energy. Portfolio C4 includes battery storage and assumes decreases in battery costs as shown in response to CEC IR1 5.3. This portfolio has a relatively higher LRMC as a set of complementary renewable resources, such as solar and wind, is required to deliver dependable capacity year round. It is not that any one individual resource has an unusually high UEC, rather it is multiple resources are required to serve the load across the seasons with some resource types being winter-oriented and others summer-oriented. Those seasonally oriented resources would serve the same annual energy (which is the denominator of the LRMC calculation), but are collectively adding more costs into the numerator of the LRMC calculation. Furthermore, the utility is required to manage the energy from these resources, even if that energy is not needed or is delivered at a time when favourable market prices are available.

51. Reference: Exhibit B-2, Page 180

Figure 11-1: Portfolios with Varying DSM Levels

51.1 Please discuss the costs for the renewable wind and solar energy being used in these portfolios, along with battery technology for assuring capacity in the daily delivery of the energy when it is needed, relative to the potential progression over time for the decline of the costs for these alternatives.

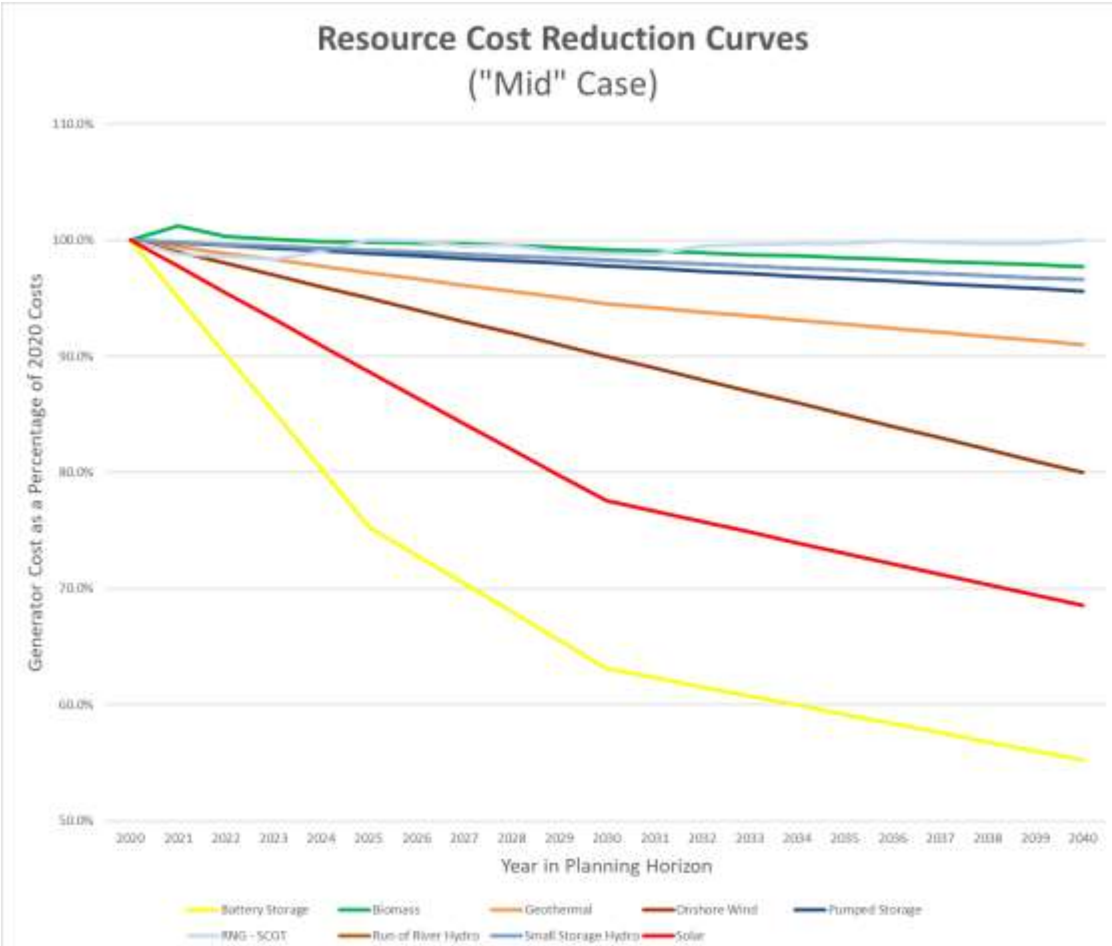
Response:

FBC anticipates changes in resource costs for solar, wind, and battery technologies, as well as other technology types, over the planning horizon based on NERL Annual Technology Baseline data[16] as provided to FBC by BC Hydro as part of its Resource Options Inventory update.

The graph below shows the FBC assumed "Mid Case" progression of changes in generator costs for the various resource types considered in the resource portfolio over the planning horizon. Other components of the UEC, such as interconnecting transmission and wheeling costs, do not decrease over the planning horizon in the portfolio model. The graph also shows that the most

16 National Renewable Energy Laboratory (NREL), 2020 Annual Technology Baseline.

significant generator cost declines over the planning horizon relate to wind, solar, and battery storage.



51.2 Please discuss whether or not FBC has captured at least a sensitivity case if not a full portfolio case with future technology paths and their timing examined.

<u>Response:</u>

All scenarios, with the exception of portfolios C5, assume the ‘Mid Case’ estimate of resource cost decreases in clean and renewable technology as illustrated in the response to CEC IR1 51.1. Portfolio C5 assumes the ‘High Case’ where costs come down in price at a slower rate than the ‘Mid Case’.

52. Reference: Exhibit B-2, Page 181

Figure 11-2: Portfolios with Market Access versus Self-Sufficiency

52.1 Please comment on the logic that when all jurisdictions are planning for self-sufficiency with a margin of surplus to cover for potential error, that the electricity markets will have surplus low-cost energy available and whether or not the reverse would be true.

<u>Response:</u>

FBC confirms that, as discussed in Section 2.4.2 of the Application, the western US energy crisis of the early 2000s resulted in an expansion of resources, and the Mid-C power market has generally been in an energy and capacity surplus since the mid-2000s. During periods of surplus in the Pacific Northwest, namely during freshet with increased hydro run-off, there can be times when there is abundant amounts of low-cost energy available in the market. As mentioned throughout the Application, FBC plans to take advantage of low-cost energy market opportunities when it is economic to do so.

However, the amounts of surplus low-cost energy available, and whether or not the reverse would be true, is dependent on each utility's own resource and self-sufficiency planning, market and weather conditions, as well as various government policies and other factors that would influence electricity markets over various periods throughout the year.

52.2 Please comment on whether or not the self-sufficiency portfolios have FBC forecasts for reductions in the cost of supply from those sources embedded in the portfolio and whether or not FBC expects to assess the cost reductions as they occur and make decisions to add such supply as it becomes cost effective.

Response:

FBC confirms that all of FBCs portfolios, including the self-sufficiency portfolios, have "Mid-Case" (or expected) forecast resource cost reductions embedded into the cost of the resource options, with the exception of portfolio C5 which has the "High case" for cost reductions. When FBC approaches a decision point for meeting its forecast energy and capacity requirements in the future, it will assess the cost-effectiveness of alternative resource options in a future regulatory process, such as an application for a CPCN, if required.

52.3 Please comment on the efficacy and cost efficiency of very tight planning for matching supply and demand along with market purchases as the contingency supply option in the event of variability from the plan, as opposed to the comment about the market being used only to the point of 2030.

Response:

The LTERP is a high-level planning tool that is intended to help guide resource decisions. Modelled portfolios can be utilized to compare resource mixes and themes among the different scenarios. From a high-level planning perspective a few megawatts of capacity has little impact on reliability. However, in the event FBC brings forward an application for a CPCN, there will need to be further analysis on different sizing options relative to the future needs of the utility, the operating environment at the time of the application (for example, higher levels of electrification and EV charging), and requests from any new large customers wanting to connect to the system. Whether planning for less surplus resources available for each month of each year, in other words, a "very tight planning" strategy, or more 'lumpy' resource investments is preferred will depend on the circumstances and resources, including the viability of market supply, available at the time.

The discontinuation of market capacity after 2030 recognizes that June is no longer an exception, and in the future, when other resources are required to support the summer capacity requirements, June gaps should also be considered at that time. While on a long-term planning basis FBC does not intend to use the market to meet expected capacity load, market capacity is recognized as a contingency resource in the PRM model. FBC does not consider relying on the market as both a base and back-up resource to be prudent in the long run. However, if small gaps emerge while resources are being developed, and no other option were available, FBC would attempt to access the market for capacity purposes.

52.4 Please comment upon the potential for self-sufficiency in BC to become competitive to the market energy because it will potentially be the marginal energy ongoing in the future in most jurisdictions.

Response:

It is difficult to predict with certainty which jurisdiction will specifically have the marginal energy in the future or which jurisdiction will be the most cost competitive. Utility resource planning, in addition to state and provincial legislation, is rapidly evolving around clean energy. Additionally, each utility's resource position may change year-over-year as many utilities in the Pacific Northwest are hydroelectric dependent and water availability can vary considerably in each basin. The variability of water along with the intermittency of solar and wind resources makes it difficult to state which jurisdiction will have marginal energy in any given hour, season, or water year. FBC does expect an increase in intermittent renewables within the region in response to a decrease in fossil fuel generation, such as coal, which is likely to lead to times of energy surplus, as well as times of energy scarcity, in the market.

53. Reference: Exhibit B-2, Page 183

Figure 11-3: Portfolios with varying levels of Clean or Renewable Resources

53.1 Please comment on the C3 scenario versus the C4 scenario with respect to what replaces RNG SCGT in the C4 and C5 scenarios that drives up the average cost so extensively. Is it primarily the Biomass capacity and energy option that is costly?

Response:

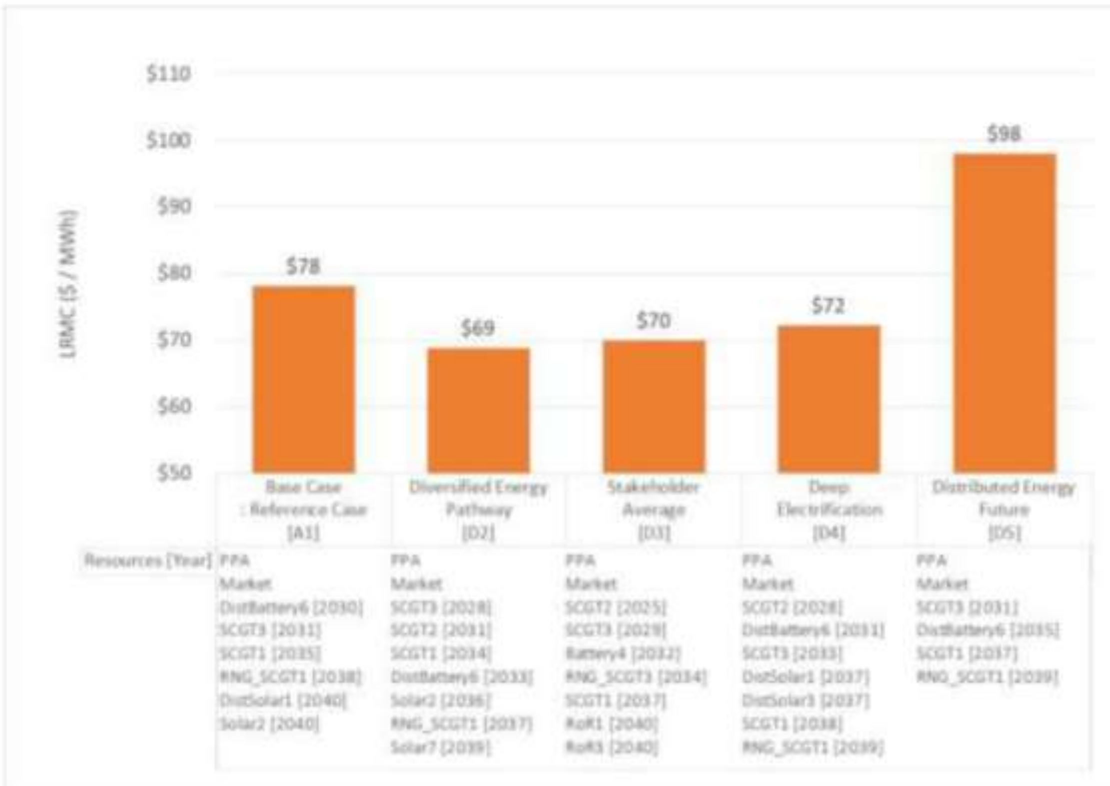
The cost of biomass capacity and energy resources is not what drives up the portfolio C4 costs when compared to portfolio C3, as the Biomass1 resource costs are only considered in the last year of the planning horizon. Instead, the reason that portfolio C3 is more cost effective than portfolios C4 and C5 is that it more appropriately utilizes the strengths of both the capacity and energy resources. In portfolio C4, the largest contributors to the LRMC are the new incremental resources: Wind5, Solar7, and Battery4.

Capacity is best provided by capacity-oriented resources such as an RNG SCGT or battery storage. While the use of a larger battery in portfolio C4 and portfolio C5 helps to provide some additional capacity in peak hours, battery storage has limitations, as discussed in the response to CEC IR1 44.2.

When intermittent energy resources are used to provide capacity (which is the case in portfolios C4 and C5), two things occur: first, the capacity provided by the energy resources is both intermittent and seasonal (therefore requiring more resources to ensure the capacity is available when needed), and second, much of the energy may be produced at times when more cost-effective market resources would otherwise be available. Together, these factors are responsible for the higher costs of portfolios C4 and C5 compared to portfolio C3.

54. Reference: Exhibit B-2, Page 184

Figure 11-4: Portfolios based on Load Scenarios



54.1 Please comment on the SCGT3 options and whether or not they could be capable of accepting synthetic methane in the future as a clean version and how this gas supply option might become a significant reality with the evolution of the hydrogen strategy and the carbon taxing environment.

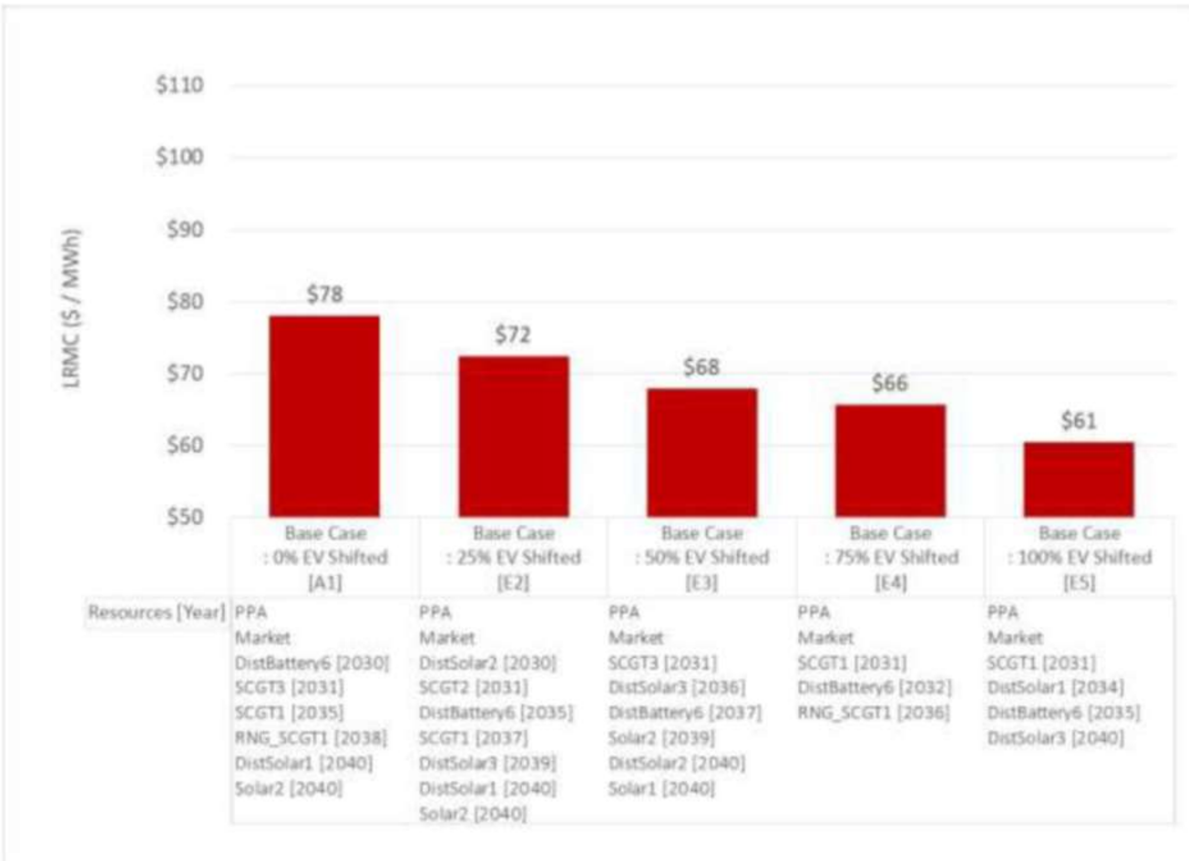
Response:

In the 2021 LTERP, there are only two types of gas peaking plants considered: 1) an SCGT that runs on conventional natural gas, and 2) and RNG SCGT that runs on RNG supplied by FEI. From a gas consumption perspective, the RNG SCGT and SCGT units are equivalent loads connected to the gas system, and therefore have the same UCC, and there would be no impact in using synthetic methane as fuel which has the same chemical composition as methane from RNG or conventional gas.

There is emerging gas turbine technology that may be capable of accepting blends of methane/hydrogen or pure hydrogen, but this was not explicitly included as a resource option in the LTERP.

55. Reference: Exhibit B-2, Page 186

Figure 11-5: Portfolios based on Different Percentages of EV Charging Shifting



55.1 Please comment on the requirements for EV charging shifting as the percentage shifts to 100% favourable timing for charging, particularly the specific timing to avoid capacity peaks both for the generation supply and for the local electrical infrastructure system.

Response:

EV charging will optimally occur in non-peak demand periods to mitigate impacts on the FBC system. FBC's daily peak hours are typically between 4 pm to 9 pm, with the system annual peak typically occurring sometime during December or January, as noted in Section 2.2.1. As daily EV charging loads are shifted, it will likely be necessary to ensure this load is shifted in a manner that avoids producing a second peak during normal non-peak hours (i.e., overnight light-load periods).

As shown in the response to RCIA IR1 33.3, there is an opportunity to shift typical EV charging load from peak demand periods and minimize the contributions of those loads to inadvertently creating a second peak. This may involve randomizing off-peak charging periods for EV charging to ensure sufficient load diversity over these non-peak hours. It may also involve incenting customers to voluntary reduce their EV charging loads to maximize the amount of non-peak hours over which a customer's EV is charged, helping to minimize the overall contribution of these loads to system demand during non-peak hours.

55.2 Please explain how this is accomplished so cost effectively that the portfolio scenarios drop significantly from the base case.

Response:

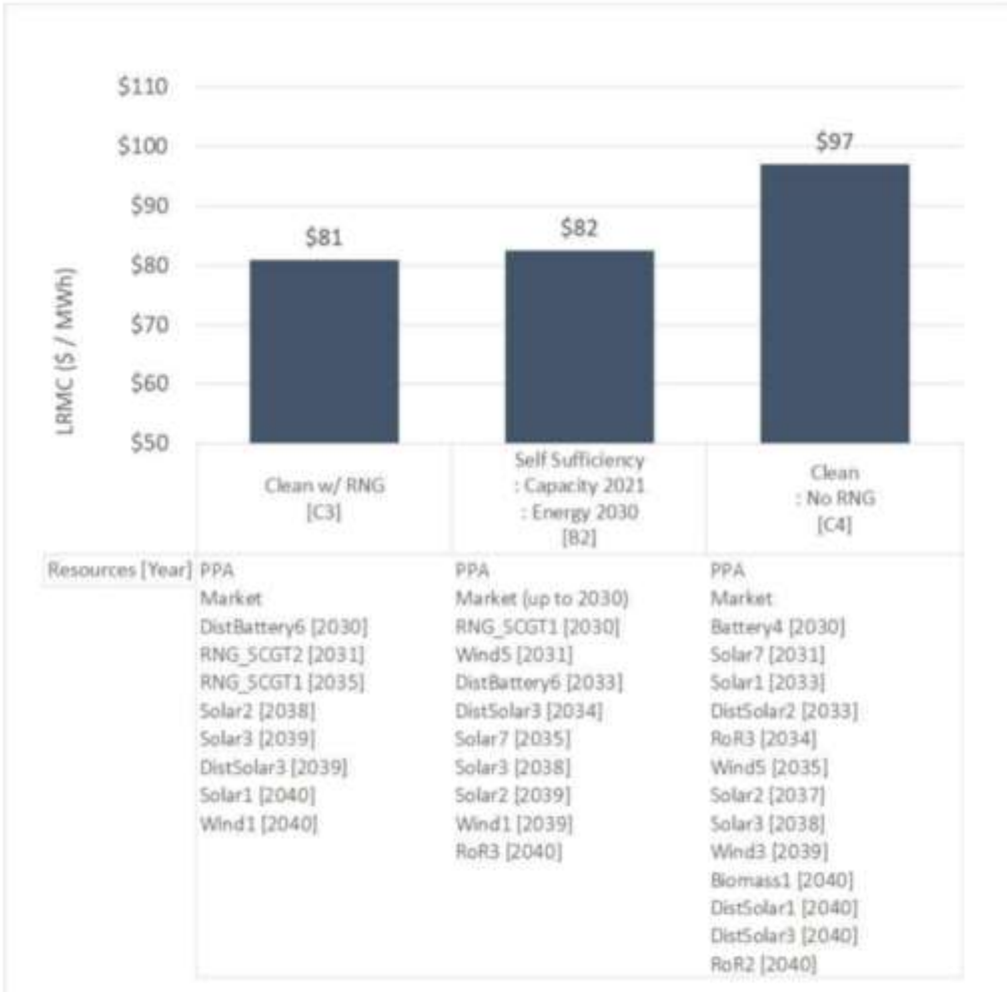
The LRMC value drops significantly from $78 per MWh in the base case to $68 per MWh with 50 percent EV Shifted, and $61 per MWh with 100 percent EV Shifted. This demonstrates the large impact that capacity resource requirements have on the LRMC and the degree to which EV adoption has a potential to be both a risk and an opportunity for the utility. Deferring capacity requirements through an EV charging mitigation program has a significant impact on the optimal portfolio solution, specifically the decreased need for incremental capacity resources and the corresponding costs.

The LRMC is calculated using the Average Incremental Cost (AIC) approach as detailed in Appendix L. In simple terms, the AIC approach considers the incremental costs associated with serving the incremental load, after netting out any changes in cost associated with serving the existing load. The costs in the portfolio, which are the numerator of the LRMC, are strongly driven by the capacity requirements given the need for capacity self-sufficiency. Decreasing the capacity requirements decreases the need for resources, leading to a decrease in costs in the numerator, but the same volume of energy is being supplied. EV vehicles still need to charge their batteries, but, with shifting, charging is assumed to be occurring at a time when existing capacity can be further utilized such as the middle of the night. Energy supplied is the denominator of the LRMC which yields the dollars per MWh unit.

The conclusion to be drawn from Figure 11-5 is that an EV program designed to encourage and shift charging from evening peak hours when customers return from work to non-peak times, such as the middle of the night, will help to improve the efficiency of the system and therefore decrease the unit cost of incremental energy.

56. Reference: Exhibit B-2, Page 190

Figure 11-7: Portfolios Considered for Preferred Portfolios



56.1 Please comment on why FBC would include C4 as a preferred option when it is so clearly expensive beyond repair.

Response:

The preferred portfolios illustrate two important high-level differences. First, a comparison of portfolio C3 versus C4 shows the cost difference between allowing RNG SCGTs or no SCGTs at all. Second, the comparison of portfolio C3 versus B2 shows the cost difference between allowing market energy over the planning period, or just up to 2030 (after which energy self-sufficiency is required). Each of the preferred portfolios represents a potential future portfolio option.

However, portfolio B2 has a marked difference as this portfolio choice impacts not only how FBC will serve future load, but also how a portion of its existing load will be served. Currently, FBC uses the market as an energy resource to serve existing load. The LRMC reflects only the incremental cost to serve incremental load, after netting-out changes in the cost to serve existing load. Therefore, the LRMC of portfolio B2 cannot be directly compared with the other portfolios without also considering other cost metrics. Instead, the average cost must be examined to take into account the impact of how existing load is met in addition to incremental load.

The average costs for all three portfolios are provided in the table below. This is also shown in Table 11-2 on page 193 of the Application. This table demonstrates that portfolio C4 is not "so clearly expensive" when appropriately compared with the other portfolios.

	Portfolio C3	Portfolio B2	Portfolio C4
Average Cost of Energy to serve all Portfolio load ($ per MWh)	$76	$79	$78

56.2 Please comment on why the third preferred portfolio does not contain the further EV charging shifting for its cost effectiveness and efficient use of resources, albeit with some risks that may favour a final selection of another option but one compatible with trying to reach the most cost-effective EV charging cost options.

Response:

None of the preferred portfolios include capacity savings from a potential future EV charging mitigation program. Establishing the costs of the preferred portfolios without an EV charging mitigation program is akin to evaluating portfolio costs before DSM, thereby establishing the avoided costs of such a program.

FBC currently does not have an EV charging mitigation program in place, nor has it proposed a specific program with anticipated savings for the BCUC to accept within this LTERP Application. FBC is seeking support to develop such a program as part of the Action Plan outlined in Section 13.2.

However, FBC recognizes that having an EV charging mitigation program in place does change the capacity-related requirements as shown in Figure 11-5. FBC expects to include an EV charging mitigation program for the base/preferred portfolio as part of the planned assessment work in the next few years related to determining resource options, in case they are required, ahead of submission of the next LTERP.

57. Reference: Exhibit B-2, Page 197

To address load increases greater than the Reference Case in the shorter term, FBC has several options as part of its contingency planning. These include the following, which could be implemented separately or in combination, depending on the specific energy and capacity requirements:

- Increase market energy purchases;
- Increase PPA energy and capacity (if not already at its maximum);
- Implement other EV peak shifting options discussed in Section 2.3.2;
- Ramp up DSM to higher incentive levels, and
- Accelerate new resources from the preferred portfolios which require shorter lead times, such as an SCGT plant using RNG or battery storage units.

57.1 Please provide the quantitative availability and potential prices for these contingency options so that they can be assessed in comparison to the need in the event of unforeseen events compromising the base preferred portfolio case.

Response:

The following table lists the identified contingency resources, total resource size,[17] the potential prices, and anticipated lead-times.

	Energy	Capacity	Cost	Lead Time [18]	Comments
Increase Market Purchases (Up to approximately 3,241 GWh)	Yes	*[19]	$28 to $49/MWh	1 day	FBC has improved reliability in access to market energy through the CEPSA. UEC shown in Table 10-2.
Increase PPA Energy and capacity (Up to 1,752 GWh and 200 MW capacity)	Yes	Yes	$49 to $60/MWh, $101 to $123/kW-year	1 day (To avoid penalty, 1 year)	FBC can increase PPA capacity to meet changing peak loads (at the cost of increasing the capacity ratchet). UEC and UCC shown in Table 10-2.

[17] Total resource size is distinctly different than quantity available for the resources of market purchases and PPA (BC Hydro RS3808). The amount of remaining resources available at a specific time depends on the year in the planning horizon, the load scenario, and the portfolio characteristics.

[18] Lead Times to implement new resource options are high-level estimates only and may be extended depending on the nature of the project.

[19] FBC does not plan to rely on market capacity to meet expected load. However, if it is required to do so due to a contingency event, FBC will purchase market capacity.

	Energy	Capacity	Cost	Lead Time [18]	Comments
Implement other EV Peak shifting options		Yes	$TBD/kW-year	2 years	EV charging shifting pilot program is being developed. Other potential options listed in Table 2-1 have not yet been fully defined.
Ramp up DSM to higher incentive levels **(Up to an additional 6.5 GWh of incremental savings per year)**	Yes		$183 to $234/MWh	1+ years	Incrementally higher levels of DSM. Would require BCUC approval to increase spending and requires time to engage with Trade Ally Network. Table 3-1, FBC LT DSM Plan.
Accelerate new resource options: **RNG SCGT** **(50 to 100 MW+ installed capacity)**		Yes	$131 to $148/kW-year	4 years	Cost-effective resource option for year-round dispatchable capacity. UCC shown in Table 10-2.
Accelerate new resource options: **Battery** **(25 to 50 MW installed capacity)**		Yes	$226 to $267/kW-year	2 years	Capacity resource with likely least path of resistance and sized to be a stop gap. Costs likely lower in future years. UCC shown in Table 10-2.

57.2 Please define quantitatively the types of short-term issues that could create the need for the contingency resources and provide a likely probability for such events as may have known historical evidence to support the frequency and severity of their occurrence.

Response:

In the short-term (2021-25), weather-driven load events and/or the addition of large new customer loads have the most potential to increase FBC load requirements beyond the Reference Case load forecast. While FBC's LTERP does reference a recent study on climate change,[20] FBC is not aware of any studies that can quantitatively determine the probability or severity of anomalous weather events. Furthermore, although the Reference Case load forecast assumes that 75

[20] https://www.nrcan.gc.ca/climate-change/impacts-adaptations/canadas-changing-climate-report/21177

percent of large known future loads will occur, there is no historical data for this forecast component and, therefore, prediction intervals cannot be calculated directly.

In order to account for future variability in the Reference Case load forecast, FBC developed uncertainty bands around the Reference Case load forecast, as detailed in Section 3.6. The assumption is that one out of every ten years, peak demand will exceed the uncertainty bands.

Finally, as outlined in the response to CEC IR1 57.1, over the short-term horizon, FBC would increase either market purchases or PPA energy and capacity purchases to address any issues that should arise.

58. Reference: Exhibit B-2, Page 199

Table 11-3: Portfolio Analysis Conclusions

Time Frame	Conclusion
Short Term (2021 - 2025)	• Optimization of PPA and market purchases • Monitor expiring EPAs and other market opportunities within BC • Assess resource options and be prepared to implement contingency plans if market conditions or loads increase
Medium Term (2026 - 2030)	• Optimization of PPA and market purchases • Assess resource options in next LTERP • Be prepared to implement contingency plans if market conditions or loads increase • Begin development of new generation resources, such as those included in the preferred portfolios
Long Term (2031 - 2040)	• Optimization of PPA and market purchases if market continues to be cost-effective and reliable • Implement new generation resources, such as those included in the preferred portfolios • Plan for new generation resources, beyond the preferred portfolios, for 2033 or sooner if PPA not renewed

58.1 Please explain why FBC would not be building experience and tools for shifting EV charging to more cost-effective timing as early conditioning of the market would only be expected to be useful in the long-run effectiveness of these options.

Response:

As discussed in the response to RCIA IR1 5.1, FBC has already begun work on a demand response pilot program which includes EV chargers in its scope. This pilot will help support early conditioning of the market while also helping inform FBC on options and tools available for shifting EV load in the long run.

58.2 Please explain why FBC would not be looking to experiment with battery technologies to begin to gain experience in the use of these and to develop information with respect to the technology development cost-effectiveness potentials.

Response:

FBC has been closely monitoring developments with battery storage, and is currently planning a pilot of a number of Level 2 chargers with integrated battery storage (40 to 60 kWh) for charging FBC fleet vehicles at its Kelowna-Springfield office location. This pilot is intended to assess the use of battery-assisted demand-shaving and time-shifting of charging events, helping further inform FBC on potential future options for reducing peak loading related to EV charging.

58.3 Please explain why the Medium Term does not contain explicit development of the SCGT – RNG option, because of its cost-effectiveness and clean characteristic advantage over other portfolio options.

Response:

Table 11-3 does not include the development of specific resource options because it is intended to provide a high-level summary of the portfolio analysis conclusions as the mix of specific resources ultimately selected in the future may change.

12. STAKEHOLDER, INDIGENOUS AND CUSTOMER ENGAGEMENT

59. Reference: Exhibit B-2, Page 212

> The information gathered through these activities is incorporated into the LTERP process in a number of ways, such as by informing FBC's planning and analysis, helping to determine the preferred resource option portfolios, identifying long term planning issues of concern to a number of stakeholder and Indigenous groups, and identifying interested stakeholders who may become more engaged in the LTERP process. FBC recommends continuing with the RPAG, community and Indigenous engagement activities as part of the Company's next long-term resource planning process in order to build on the interest and feedback gained through these initiatives.

59.1 The CEC considers that the RPAG and all of FBC's other public and stakeholder engagement processes have been quite valuable. Please provide the cost FBC has incurred in carrying out these engagement processes and show them as a % of the LTERP total expected cost.

Response:

FBC's cost related to its 2021 LTERP stakeholder engagement is approximately $7 thousand (excluding any costs relating to FBC staff time), or 3.3 percent of the total LTERP development costs of approximately $200 thousand.

60. Reference: Exhibit B-2, Page 214 to 217

1. Continue to monitor the planning environment

2. Monitor potential load drivers to determine if a particular load scenario is emerging

3. Contingency resource(s) assessment

4. Implement program to help shift home EV charging

5. Consider initiatives to manage large loads

6. Continue to optimize the PPA and market purchases

7. Review PPA prior to expiry

8. Transition to clean market purchases

9. Monitor potential available power supply opportunities

10. Continue Stakeholder, Indigenous Community and Customer Engagement

11. Assess transmission and distribution capital infrastructure requirements

12. Prepare Submission of next LTERP

60.1 Please explain why FBC would not be in this period assembling the most cost-effective option for and SCGT – RNG or RG for future capacity needs, distinctly separate from #9 monitoring.

Response:

Action Item #3 - Contingency resource(s) assessment in Section 13.2 describes FBC's intent to explore its potential resource options identified in the LTERP in more detail in the next few years. FBC expects these potential resource options to include SCGT plants using RNG or other renewable gas as fuel.

60.2 Please explain why FBC would not have initial steps and piloting of battery technologies so that as they emerge in relevance to FBC's future planning FBC has the experience to be incorporating best options including integration with the renewable energy supply markets to ensure FBC fully understands the technology needs and requirements before this becomes a key part of future LTERPs and FBC's operations.

Response:

As noted in the response to CEC IR1 58.2, FBC is planning to pilot the deployment of a small-scale battery storage installation for supporting Level 2 EV charging infrastructure. Additionally, FBC is monitoring developments regarding deployment of utility-scale battery storage in order to help inform how this technology may address resource planning challenges in the future.