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December 23, 2021

BC Solar & Storage Industries Association
PO Box 33019, West Vancouver, BC
V7V 4W7

Attention: Mr. Steve Davis

Dear Mr. Davis:

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 BC Solar and Storage Industries Association (BCSSIA) 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 BCSSIA 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

1.0 Topic: Transmission of Supply Resources Located Outside FBC Service Territory to the FBC Grid

Reference: Exhibit B-1, Section 10.3, Resource Options Evaluation, Table 10-1 (page 165, PDF 196 of 852), "Resource Options Type and Size Summary".

Footnote 179 of Table 10-1, Resource Options Type and Size Summary, states:

"The FBC Resource Option Report and the portfolio analysis include projects outside the FBC service territory and assume there will be BC Hydro long-term transmission available to deliver the power from these projects to the FBC grid."

Footnote 180 of Table 10-1 states:

"On-shore wind options included in the FBC Resource Option Report include projects greater than 100 MW. FBC's Scheduling Agreement with BC Hydro currently only allows wind projects up to 100 MW. Section 5 of the Scheduling Agreement also requires 100% back-up of wind resources which has not been factored in the analysis."

1.1 What tariff or regulation allows FBC to requireBC Hydro to deliver electricity from supply resource projects outside FBC service territory to the FBC grid?

Response:

The output of generation resources located outside of the FBC service territory can be delivered utilizing the BC Hydro Open Access Transmission Tariff (OATT) and associated rate schedules. Information on this service can be found at the following link:

https://www.bchydro.com/toolbar/about/planning_regulatory/tariff_filings/oatt.html

1.2 Is it the FBC-BC Hydro Scheduling Agreement that allows BC Hydro to deliver electricity from supply resource projects outside FBC service territory to the FBC grid? If so, please provide that Agreement.

Response:

Please refer to the response to BCSSIA IR1 1.1.

1.3 Does FBC's Scheduling Agreement with BC Hydro allow solar projects (in addition to wind projects)?

Response:

FBC confirms it can schedule solar projects' power using BC Hydro transmission to the FBC service territory. The terms and conditions of the BC Hydro OATT, as well as the Scheduling Agreement, apply. Please also refer to the response to BCSSIA IR1 1.1.

1.4 Does FBC's Scheduling Agreement with BC Hydro limit the size of solar projects to 100 MW (in addition to limiting wind projects to 100 MW)?

Response:

The Scheduling Agreement refers to any resource that is subject to change due to varying conditions (wind and sun, for example) after the scheduling timelines for that hour have passed. The 100 MW limit is cumulative for all resource types. However, the 100 MW number is subject to change as FBC's resource mix changes. If FBC adds resources that provide dependable and dispatchable capacity, the 100 MW limit is expected to increase.

1.5 Does FBC currently have BC Hydro delivering electricity from supply resource projects outside FBC service territory to the FBC grid? If so what projects and how much energy?

Response:

FBC has never attempted to take supply from any project outside FBC's service territory.

1.6 Has FBC previously had BC Hydro deliver electricity from supply resource projects outside FBC service territory to the FBC grid? If so what projects?

Response:

Please refer to the response to BCSSIA IR1 1.5.

1.7 Has BC Hydro ever denied a request to deliver electricity from supply resource projects outside FBC service territory to the FBC grid? If so, what projects were requested? And what reasons were given for denying that/those request(s)?

Response:

Please refer to the response to BCSSIA IR1 1.5.

1.8 Has FBC previously requested BC Hydro to deliver electricity from supply resource projects outside FBC service territory to the FBC grid, and found that BC Hydro advised that insufficient long-term transmission was available to deliver the power from those projects to the FBC grid?

Response:

Please refer to the response to BCSSIA IR1 1.5.

2.0 Topic: Retail Access

Reference: Exhibit B-1, Appendix H – Load Scenarios Assessment Report, Section 4.3, "Key Finding 3: Opportunities Offered by New Types of Loads".

The second and third paragraphs of Section 4.3, Opportunities Offered by New Types of Loads, state:

"As British Columbia works to decarbonize its energy over the planning horizon, it is possible that some component of its strategy to do so will involve injecting hydrogen to its natural gas system. At present the production of green hydrogen via electrolysis is (given the makeup of British Columbia's generation fleet) the cleanest way to do so. While the Upper Bound assumptions for the HP load driver may be extreme, there is no question that increasing hydrogen production could substantially increase energy requirements in FortisBC's territory.

Likewise, there may be some question regarding how much growth really may be expected of the cannabis industry. It is undoubtedly true that the exponential worldwide growth of data centres to serve individuals' and companies data storage and processing needs will continue. Should more of these facilities migrate to FortisBC territory, the impact on consumption could be considerable

– even the (relatively) modest growth in floorspace assumed for Scenario 4, the Distributed Energy Pathway (nearly tripling floorspace in 20 years) results in an incremental energy requirement of 215 GWh, an increase of 5% in system energy compared to the business-as-usual forecast."

2.1 Is Retail Access permitted in FBC's service territory? If so, what are the terms and conditions for the use of Retail Access?

<u>Response:</u>

Yes, retail access is currently permitted in FBC's service territory. However, due to a number of circumstances, the practical availability of retail access is severely constrained.

Since 1999, pursuant to BCUC Orders G-27-99 and G-28-99, FBC has had an OATT and related rate schedules that enable eligible large commercial and wholesale customers to use the FBC transmission system to wheel power purchased from third parties to the location of their load within the FBC service area.

Pursuant to BCUC Order G-12-99, the rates for this service and the equivalent service offered by BC Hydro were harmonized such that the customer would only pay the rates of the utility in which service area the load was located (with the exception of loss compensation) in cases where power needed to be wheeled through both service areas.

However, Section 7 of Direction No. 8 to the BCUC, BC Reg 24/2019, contained the following language with respect to retail access.

> **Retail access**
>
> Except on application by the authority, the commission must not set rates for the authority that would result in the direct or indirect provision of unbundled transmission services to retail customers in British Columbia, or to those who supply such customers.

Until recently, the position of BC Hydro with regards to the impact of Special Direction 8 on the customers of FBC was as stated in the evidence of BC Hydro in the *FortisBC Inc. 2017 Cost of Service Analysis and Rate Design Application*:[1]

> The result of the foregoing is that there is no retail access in BC Hydro's service territory and BC Hydro retail load customers cannot use the BC Hydro OATT for retail access. The removal of retail access in BC Hydro's service territory did not impact potential FortisBC retail access customers. [Emphasis added.]

However, in the BCUC Indigenous Utilities Regulation Inquiry Final Report dated April 30, 2020, the Panel stated,

> In the Panel's view, the wording of Direction 8 does not differentiate between BC Hydro's retail customers or retail customers of any other public utility. Direction 8 does not limit customers to be a retail customer of any particular public utility, simply that they be a retail customer. Neither the term "Retail Customer" nor the term "retail" is defined in the Direction 8, the Hydro and Power Authority Act, the UCA or the Interpretation Act. However, the Oxford dictionary defines "Retail" as:
>
> The sale of goods to the public in relatively small quantities for use or consumption rather than for resale". We therefore interpret Direction 8 to preclude the use of BC Hydro's transmission system to wheel electricity to any customer who will directly consume that electricity in British Columbia whether it is a customer of BC Hydro or another public utility.

Given this, BC Hydro has communicated to FBC that while it maintained its previous position during the Indigenous Utilities Regulation Inquiry process, the Panel's view in the Final Report effectively precludes it from allowing the use of its transmission system in the provision of retail access to the customers of FBC.

Since delivery of power originating from outside of the FBC service area cannot practicably be delivered to a load within the FBC service area without the use of the BC Hydro system, the most likely use of retail access is effectively unavailable to FBC customers, despite FBC having the

[1] Exhibit C1-3, page 4, lines 12-15 (These comments were based on Special Direction No. 7 which contained similar language regarding retail Access).

BCUC approved rate schedules intended to support the practice.[2] This leaves only transactions for retail access that take place entirely within the FBC service area as being possible at this time.

2.2 If Retail Access is permitted, have any customers requested to use it? Did they use it successfully? When and for how long?

Response:

Retail access has never been utilized to serve customer load in the FBC service area, though the transmission service rates have been used by eligible customers to deliver self-generated power to points of delivery with the BC Hydro system.

2.3 If any customers have used Retail Access, please describe some specific examples (appreciating confidentiality restrictions).

Response:

Please refer to the response to BCSSIA IR1 2.2.

[2] Use of the FBC Transmission Service rate schedules is still possible to wheel power that is both produced and consumed within the FBC service area.

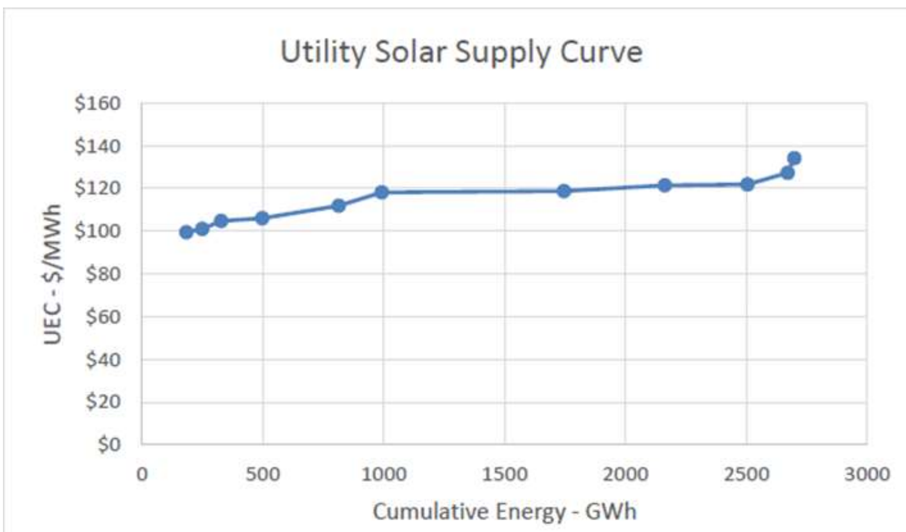
3.0 Topic: Information on Selected Subset of Solar Projects.

Reference: Exhibit B-1, Chapter 11, Section 11.3.8, "Portfolios Considered for Preferred Portfolios," and Appendix K – Resource Options Report, Section 3.3.3, "Utility-Scale Solar Power".

On lines 3 – 5 on page 42 of Section 3.3.3 (PDF 589 of 852) the following can be found:

"FBC analyzed a subset of 11 solar projects ranging in nameplate capacity from 17 MW – 490 MW in its portfolio analysis. The supply curve for these options is provided in the following figure."

Figure K3-26: Solar Supply Curve



In Table 11-2, (in Chapter 11, PDF 223 of 852), Preferred Portfolio C4 - Clean with No RNG SCGT, lists three solar projects [and their In-Service Dates] in its Resource Mix; Solar7 [2031], Solar1 [2033], Solar2 [2037] and Solar3 [2038].

3.1 What is the total amount of capacity (MW) of all 11 projects shown in figure K3-26?

Response:

The table below provides the installed and dependable capacity (in MW), the amount of energy (in GWh per year), and the average annual Capacity Factors (in percent) for each of the 11 solar projects. The total installed capacity and total annual reliable (cumulative) energy for all 11 projects is 1,662 MW and 2,698 GWh, respectively.

Resource	Installed Capacity (MW)	Average Annual Dependable Capacity (MW)	Annual Reliable Energy (GWh)	Average Annual Capacity Factor (%)
Solar1	17	4	27.5	18.8
Solar2	39	9	65.0	19.1
Solar3	47	11	78.7	19.2
Solar4	93	24	170.2	20.9
Solar5	99	23	166.1	19.2
Solar6	106	24	177.4	19.1
Solar7	110	26	183.9	19.0
Solar8	177	45	316.2	20.3
Solar9	216	48	341.2	18.0
Solar10	268	59	417.4	17.8
Solar11	490	107	754.4	17.6
Total	1,662	380	2698.0	18.5

The monthly dependable capacity assumed available to serve peak hours in the winter months, such as December and January, is considerably lower (and approaches zero) while the monthly dependable capacity assumed available to serve peak hours in the summer months, such as July and August, is considerably higher than the annual average dependable capacity.

3.2 What is the total amount of energy (GWh/year) of all 11 projects?

Response:

Please refer to the response to BCSSIA IR1 3.1.

3.2.1 Is that total equal to the approximately 2,700 GWh of Cumulative Energy shown on Figure K3-26? If not, please explain the difference?

Response:

Confirmed.

3.3 What is the average annual Capacity Utilization Factor (%) of all 11 projects?

Response:

Please refer to the response to BCSSIA IR1 3.1.

3.4 Please provide information on each of the 11 solar projects for the following categories:

1. Energy, in GWh/year.
2. Capacity (name plate), in MW.
3. Average Dependable Capacity (MW).
4. Capacity Utilization Factor, annual (%).
5. Approximate latitude, to the nearest degree.
6. Region, e.g., Okanagan, Kootenays, Caribou, etc., and whether inside or outside of FBC service territory.
7. Style of solar panel (i.e., fixed tilt, or otherwise).
8. Irradiance, average project multi-year Global Horizontal Irradiance (GHI) value, in kWh/sq.m/day, from the National Energy Resource Laboratory or "NERL".
9. Orientation, i.e., South facing with latitude tilt, two axes, tracking or otherwise.
10. Installed Cost, in $/Watt direct current (Wdc).
11. Charge for wheeling and losses.
12. Charge for integration.
13. Unit Energy Cost, in $/MWh.
14. Unit Capacity Cost, in $/kW-year.

Response:

Details regarding uniquely identifiable resources is considered confidential. The following table provides the ranges and average value of the 11 solar projects for the requested categories. As noted in the 'Comments' column, more detailed information for some of the categories in the table for the individual projects is provided in other IR responses.

Category	Values	Comments
Energy, **GWh per year**	Range: 27.5 – 754.4 Average: 245.3	Refer to BCSSIA IR1 3.1 for individual project data
Capacity (nameplate), **MW AC**	Range: 17 to 490 Average: 151	Refer to the response to BCSSIA IR1 3.1 for individual project data
FBC Average Dependable Capacity, **MW AC**[3]	Range: 4 to 107 Average: 35	Refer to the response to BCSSIA IR1 3.1 for individual project data
FBC Capacity Factor, annual (%) **per MW AC**	Range: 17.6 to 20.9 Average: 19.0	Refer to the response to BCSSIA IR1 3.1 for individual project data
Approximate latitude, **Rounded to the nearest degree**	Range: 50 to 54 Average: 51	Rounded to nearest degree
Region	4 in FBC service area, 7 in BC Hydro service area	'Region' was interpreted as utility service area
Style of solar panel / orientation	Horizontal Single Axis Tracker	
Insolation,[4] **kWh per m2 per day**	Range: 3.2 to 3.7 Average: 3.5	
Installed Cost, ($/W DC) **2020$ CAD**	Range: 1.47 to 1.64 Average: 1.48	'Installed Cost' was interpreted to be the cost of the generator only[5]
Charge for wheeling and losses, **$ per MWh**	Range: 15 to 16 Average: 16	For solar resources in BC Hydro's service territory, rounded to the nearest dollar. Please refer to Appendix K, Section 2.2.2.1 (page 8) for financial assumptions
Charge for integration, **$ per MWh**	N/A (0)	Please refer to Appendix K, Section 2.2.2.1 (Page 9) for financial assumptions
Unit Energy Cost (UEC), **2020$ per MWh**	Range: 99 to 134 Average: 115	Table 10-2, pages 166-167
Unit Capacity Cost (UCC), **2020$ per kW-Year**	Range: 686 to 863 Average: 753	Table 10-2, pages 166-167

[3] FBC determined the average expected output during peak hours on a monthly basis as FBC's resources and gaps vary on a monthly basis. The dependable capacity from solar resources during the winter peak approaches zero.
[4] Global Horizontal Insolation.
[5] Excludes interconnecting costs and/or wheeling which is dependent on location.

3.5 If some of the above information is confidential, for some or all the projects, please provide a range and average of each the categories listed.

Response:

Please refer to the response to BCSSIA IR1 3.4.

3.6 At a minimum please provide the above categories of information on the solar projects in Preferred Portfolio C4: Solar7 [2031], Solar1 [2033], Solar2 [2037] and Solar3 [2038].

Response:

Details regarding uniquely identifiable resources is considered confidential. The requested data that FBC is able to share publicly is presented in the responses to BCSSIA IR1 3.1 and 3.5.

3.7 None of the Preferred Portfolios listed in Table 11-2 appear to show PPA Tranche 2 in its selected resource mix. Is all the PPA usage confined to Tranche 1 or, if Tranche 2 is used, in which portfolios, under what circumstances, and to what extent is Tranche 2 selected as a resource?

Response:

The optimization routine (as described in the response to BCUC IR1 30.1) did not select PPA Tranche 2 as a resource for any of the preferred portfolios. The optimization routine does not constrain PPA usage to Tranche 1 and would select Tranche 2 as an energy resource if it were the more cost-effective solution to any of the alternatives. As shown in Table 10-2, PPA Tranche 2 Energy has a cost range of $80 to $95 per MWh depending on BC Hydro's LRMC for rate making purposes, and market purchases are forecasted to be $28 to $49 per MWh as supported by the Mid-C Electricity Price Forecast tables in Appendix E. Furthermore, due to the bundled nature of the PPA (i.e., FBC must schedule PPA capacity to receive PPA energy), in order for FBC to use PPA Tranche 2 as a resource, FBC would also incur additional PPA capacity costs while purchasing Tranche 2 energy at the higher energy rate.

3.7.1 Why does Tranche 2 not show as a separate resource in the column headed "Resource Mix"?

Response:

Please refer to the response to BCSSIA IR1 3.7.

3.8 Does FBC have an overall report of its entire Resource Options Inventory, which shows all of the key parameters being assumed about each potential resource. If so, please provide it. [Note - If specific project identifications are confidential, they may be replaced with generic names.]

Response:

FBC worked in collaboration with BC Hydro to update the BC Resource Options Report. Appendix K represents the FBC-relevant content of the Resource Options Report that has been made public. Tables 10-1, 10-2, and 10-3 provide an aggregate summary of the key attributes of the resource options considered by FBC.

4.0 Topic: Comparisons of Solar Procurement in the Pacific Northwest – Past.

Reference: Exhibit B-1, Section 2.4.2, "Pacific Northwest Electricity Generation" (PDF 85-88 of 852).

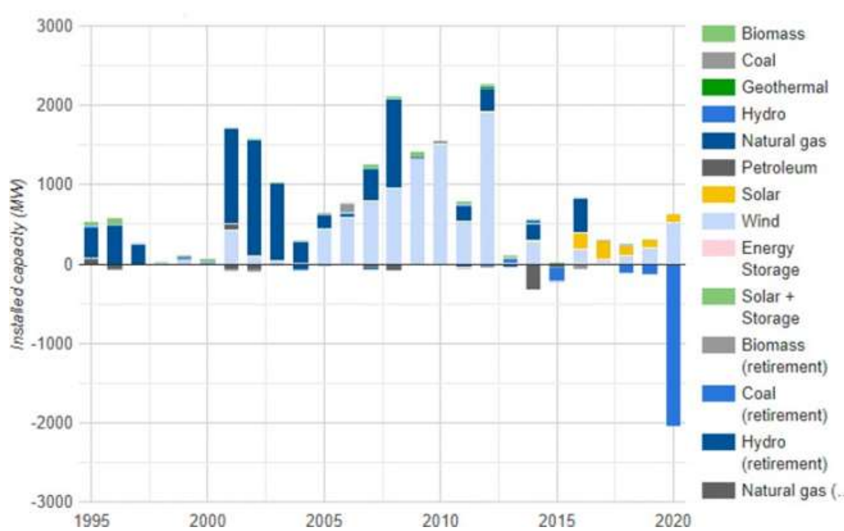
Lines 6 – 8 (page 56 in Section 2.4.2), state:

"Although there has been more solar than wind generation resources built in the Pacific Northwest in some recent years, wind still makes up a larger portion of the region's generating capacity."

Lines 3 – 8 (page 57 in Section 2.4.2), state:

"However, with coal plant retirements since 2018, lower hydro generation on average, and greater summer demand, the Pacific Northwest is facing a potential shortfall in resources. These recent developments are illustrated in Figure 2-13 below. Consequently, utilities are increasingly looking towards new renewable resources and battery storage to meet their energy and capacity needs as illustrated in the comparison table in Appendix D."

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

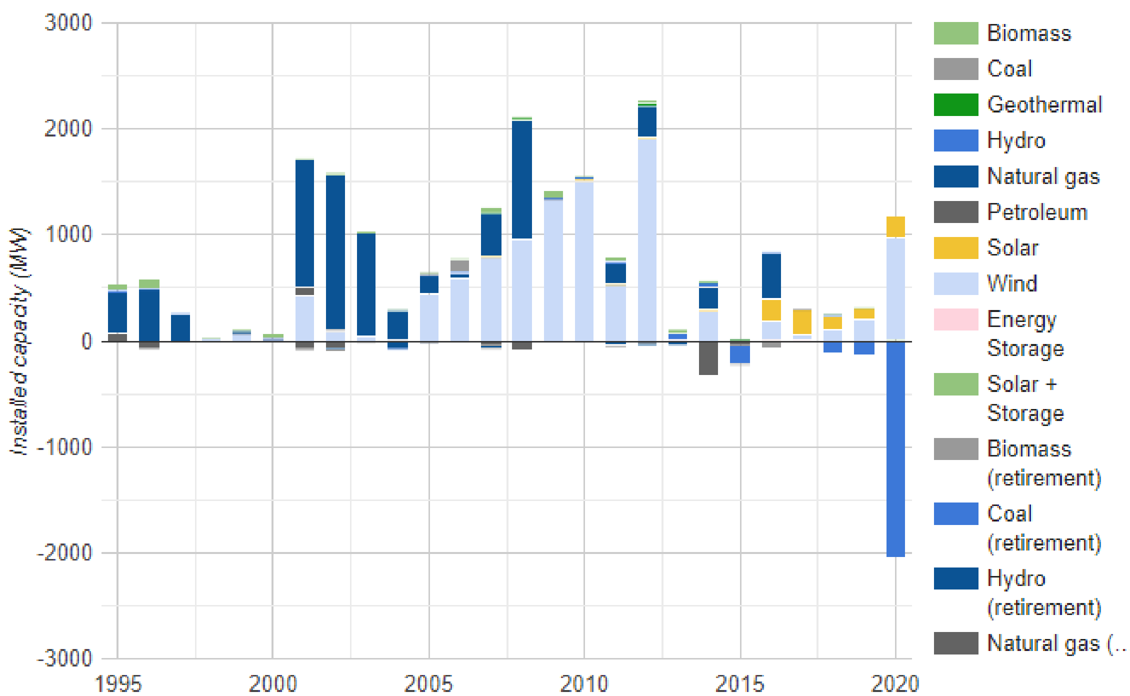


4.1 Please provide the amount of Installed Capacity (MW) for each of the resources shown in Figure 2-13 for each of the last 5 years (from 2016 to 2020) and their total over those last 5 years.

Response:

The table below provides the corresponding installed (shown by the positive values) and retired (shown by the negative values) capacity amounts for each of the resources with installed or retired capacity from 2016 to 2020 from Figure 2-13. Please note that the 2020 values in Figure 2-13 have been updated since the LTERP filing and therefore an updated Figure 2-13 is provided below as well.

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



Installed Capacity (MW)	2016	2017	2018	2019	2020	TOTAL
Wind	177	50	105	202	967	1501
Solar	209	242	130	105	218	904
Natural Gas	446	0	0	0	0	446
Biomass	-69	0	3	0	0	-66
Petroleum	0	6	0	0	0	6
Coal	0	0	-116	-139	-2048	-2303
TOTAL	763	298	122	168	-863	488

4.2 Please comment on why solar power installations exceeded wind power in the Pacific Northwest in the last 5 years.

Response:

The majority of solar built in the region[6] from 2016 to 2018 was due to *Public Utility Regulatory Policies Act* contracts in Idaho and Oregon, as well as a 56 MW solar project developed by Avangrid. The Pacific Northwest also continued to see the development of community solar installations and/or green power initiatives resulting from utilities aiming to preserve their corporate customers. Additionally, as the cost of solar has continued to decline, utilities have been analyzing and pursuing solar as part of their compliance standards.

Most of the wind projects from 2016 to 2018 were built out of region with long-term power purchase agreements to regional investor owned utilities.

[6] Northwest Power and Conservation Council Seventh Power Plan Midterm Assessment: https://www.nwcouncil.org/sites/default/files/7th%20Plan%20Midterm%20Assessment%20Final%20Cncl%20Doc%20%232019-3.pdf

5.0 Topic: Comparison of Solar Procurement in Pacific Northwest IRPs – Future.

Reference: Exhibit B-1, Appendix D: Pacific Northwest Electric Utilities Integrated Resource Plans Comparison Table (pages 1-4, PDF 350-353 of 852), and data from the National Renewable Energy Laboratory.

The Preferred Resource Strategies of the Pacific Northwest utilities shown in the Table show a desire to procure 3,485 MW of solar power by 2023, made up of the following:

"220 MW of Solar PV capacity by 2022-23 and 125 MW from 2034 – 2038" by the Idaho Power Company.

"3,000 MW solar and 3,500 MW wind by 2023", by PacifiCorp.

"Additional 265 MW of solar by 2023, followed by another 377 MW by 2029." by Puget Sound Energy.

The Preferred Resource Strategies of the Pacific Northwest utilities shown in the Table show a desire to procure a total of 727 MW of wind and other supply resource by 2023, made up of the following:

"… 500 MW of new wind, thermal upgrades in 2026 and 2027", by Avista Utilities

"… wind resources of 227 MWa by 2025", by Portland General Electric

PNW Utilities IRP Comparison Table

	Idaho Power Company	Avista Utilities	PacifiCorp	Puget Sound Energy	Portland General Electric	Seattle City Light
IRP Link	https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/our-twenty-year-plan/	https://www.myavista.com/about-us/integrated-resource-planning	https://www.pacificorp.com/energy/integrated-resource-plan.html	https://pse-irp.participate.online/	https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning	http://www.seattle.gov/light/IRP/default.asp
Latest Plan	June 2019 IRP (2019-2038)	February 2020 IRP (2021-2045)	October 2019 IRP (2019-2038)	2019 IRP Progress Report (2018-2037)	March 2019 IRP (2020-2050)	2018 Progress Report (2018-2037)
Service Area(s)	Idaho and Oregon	Eastern Washington and Northern Idaho	Pacific Power: Oregon, Washington and California Rocky Mountain Power: Utah, Wyoming and Idaho	Washington	Oregon	Washington (City of Seattle & outlying communities)
Number of electric customers	557,645[1]	340,000[2]	1,900,000	1,100,000	887,000	780,000
Current Energy/ Capacity[3] Requirement	Capacity: 3,392 MW[4] Energy: 1,810 aMW[5]	Capacity: 1,726 MW[6] Energy: 1,102 aMW	Capacity: 10,880 MW[7] Energy: 60,555 GWh	Capacity: 5098 MW[8] Energy: 2,681 aMW	Capacity: 3,976 MW[9] Energy: 2,099 aMW	Capacity: 2,841 MW Energy: 10,068 GWh

	Idaho Power Company	Avista Utilities	PacifiCorp	Puget Sound Energy	Portland General Electric	Seattle City Light
Annual Load Growth Forecast[10]	Energy: 1.0 % Capacity: 1.2%	Energy: 0.3%	Energy: 0.87% Capacity: 0.83%	Energy: 1.3% Capacity: 1.4%	Energy: 1.0% Capacity: 1.2%	Energy: 0.4%
Current Energy Portfolio Mix	46% Hydro 17% Coal 8% Natural Gas 29% Purchased Power (20% PURPA[11] & PPA[12], 9% Market Purchases)	41% Natural Gas 26% Owned Hydro 9% Contracted Hydro 12% Coal 12% Biomass, Wind, Solar and Refuse[13]	56% Coal 24% Natural Gas 10% Hydro 10% Renewable (Wind, Solar)	36% Coal 20% Natural Gas 32% Hydro Wind 10% Nuclear 1% Biomass, Other 1% ([14]	15% Coal 28% Natural Gas 15% Hydro 9% wind 33% Market Purchases (mix of renewables, hydro and thermal resources)	86% Hydro 7%Wind 5% Nuclear 1% Biogas 1% Unspecified[15]
Planning Reserve Margin	15%	Summer: 7% Winter : 16%	13%	17.8% After 2026 : 18.3%[16]	Summer: 10% Winter : 12%	Only provide WECC Target Margins: Summer: 17.5% Winter 19.2%
DSM	Energy efficiency reduces annual energy demand by 234 aMW and peak demand by 367 MW by 2038	Energy efficiency achievable potential of 235.4 aMW by 2040	Energy Efficiency and direct load control equal to 700 MW for the planning period (2019-2038)	Energy efficiency 374 MW by 2023 and 714 MW by 2037.[17]	Energy efficiency resource supply of 547.6 aMW by 2037	New conservation reaching 128 aMW by 2025 and 205 aMW by 2035
Owned Supply Resources	17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel-powered	8 hydroelectric developments, 1 coal-fired unit, 5 natural gas-fired projects, and a	10 coal facilities, 6 natural gas facilities, 1 geothermal and other, 41 hydro systems, 13 wind facilities, 2 coal mines	Shared ownership in 4 coal-fired generation units, 6 CCCT[18], 4 SCCTs[19], 3 hydro plants, 3 wind farms	7 hydroelectric plants, 5 natural gas plants, 2 coal-fired plants, 2 wind facility, 1 solar	4 major hydroelectric projects, 3 small hydroelectric projects, Landfill gas plant, BPA
	plant, share ownership in 3 coal-fired facilities	biomass plant.				Hydro PPA (40%)
Load- Resource Balance	Energy deficit: 2026 Capacity deficit: 2029	Energy deficit: 2026 Capacity[20] deficit: 2026	Energy Deficit: 2026 Capacity Deficit: Winter 2024 Summer 2028	Energy deficit: 2025 Capacity deficit: 2025	Energy deficit: 2021 Capacity deficit Winter: 2021 Summer: 2026	Energy deficit: 2028 Capacity deficit: 2028
Preferred Resource Strategy	220 MW of Solar PV capacity by 2022-23 and 125 MW from 2034-2038. Exit 3 coal units by 2022 and 2 other coal units by 2026[21]. B2H transmission line project on-line in 2026. Natural Gas generation of 222 MW from 2028-2030 and additional 300 MW in 2035 and 2038.	Adequate resources before 2022, 500 MW of new wind, thermal upgrades in 2026 and 2027. Additional long duration pumped hydro storage and demand response.	DSM (700 MW of energy efficiency and new direct control resources), incremental transmission investment, 3,000 MW solar and 3,500 MW wind by 2023, 600 MW of battery storage capacity	Energy efficiency and demand-response push natural-gas-fueled peaking plant to 2025. Additional 265 MW of solar by 2023, followed by another 377 MW by 2027. Removal of all coal generation by 2025.	Energy Efficiency (157 MWa[22] by 2025), renewable actions including wind resources of 227 MWa by 2025 and energy storage (batteries and pumped storage)	Acquisition of energy efficiency, renewable resources, and improvements in hydro generation efficiency. Major resource required earliest by 2028
Clean Energy and GHG Reduction Targets and Initiatives	Reduce average C02 of energy sources from 2010-2020 to 15-20% lower than 2005. Ending participation in 2 coal plants. Reduce average CO2 emissions from	Shift to clean energy reduces GHG emissions from 2018 levels by 71% in 2030 and 79% in 2045 100% carbon neutral energy by 2027 (Renewable	Energy Vision 2020 Plan: 1,150 MW of new wind and 999 MW of upgraded wind resources to come on-line by 2020. California: Planning target of 100% renewable and carbon-free by 2045. Oregon: 50% Renewable by	Washington State Energy Independence Act calls for utilities to invest in renewable generation to meet 15% of demand by 2020 and the Clean Energy Transformation Act requires at least	Reduction in GHG emissions of more than 80% by 2050. On track to serve 50% of customers with clean energy. Expanding and accelerating their "Electric Avenue"	Washington State Energy Independence Act calls for utilities to invest in renewable generation to meet 15% of demand by 2020 and the Clean Energy Transformation Act requires at least

The National Energy Resource Laboratory produced the following map of solar PV irradiance. (Link to data viewer: https://maps.nrel.gov/nsrdb-viewer)

The areas in yellow have a Global Horizontal Irradiance (GHI) of between 3.5 to 4.0 kWh/sq.m/day based on 19 years of US Department of Energy satellite observation.

The map shows that the irradiance in FBC's service territory is similar to most of Idaho and Montana, Eastern Washington and Western Oregon. Those areas all share a GHI of between 3.5 to 4.0 kWh/sq.m/day.

5.1 Is FBC aware that the National Energy Resource Laboratory is a respected agency of the US Department of Energy, and its solar observation data is now shared with Canada? Is it also aware that the previous Canadian solar mapping produced by Environment Canada was based on airport and Environment Canada weather station observation, which is no longer favoured by utility scale solar developers and has been replaced by long term satellite observation (correlated with ground based solar measurement from specialized sensors), such as that provided by National Energy Resource Laboratory?

Response:

FBC is aware that there are several providers of solar irradiation estimates.

FBC understands that Environment Canada’s Canadian solar maps are intended to be used as one of several early screening tools showing the potential for solar development in the various provinces in Canada. FBC has not surveyed Canadian solar developers regarding their opinion on the Canadian solar mapping produced by Environment Canada.

FBC recognizes the development of any specific solar site in BC would likely use more sophisticated solar irradiation estimates, such as synthetic solar irradiation forecasts based on satellite observation. These synthetic estimates should be confirmed by installing ground based solar measurement instruments on the site, such as a pyranometer.

The LTERP resource options analysis, which identified the 11 representative utility scale solar projects in FBC service territory, utilizes National Energy Resource Laboratory (NERL) data in its analysis of annual available irradiation. None of these sites have had the NERL synthetic estimates confirmed with ground based solar measurement from a pyranometer.

5.1.1 Has FBC utilized National Energy Resource Laboratory data for any of its analysis of potential solar resource projects? If not, why not. Does it plan to do so in the future?

Response:

Please refer to the response to BCSSIA IR1 5.1.

5.2 Please compare the median and/or range of the long-term average Global Horizontal Irradiance (in kWh/sq.m/day) in those Pacific Northwest utilities' service territories (or the states they are predominantly located in) with the long-term average Global Horizontal Irradiance that FBC has used for projects in FBC's service territory, and any of the other projects included in the subset of 11 solar projects in FBC's Resource Options Report.

Response:

The Global Horizontal Irradiance (GHI) for the 11 solar projects in FBC's Resource Options Report ranges from 3.2 to 3.7 kWh per square metre per day and has an average of 3.5 kWh per square metre per day. Therefore, the range of GHI values for these 11 solar projects is lower than the range of GHI values of 3.5 to 4.0 per kWh per square metre per day cited in the preamble for Idaho, Montana, Eastern Washington, Western Oregon and southern Alberta.

5.3 Why would Pacific Northwest utilities Preferred Resource Strategies include 3,485 MW of solar in by 2023 compared to only 727 MW of wind and all other resources?

Response:

FBC assumes that the Preferred Resource Strategies for the utilities in the Pacific Northwest IRP Comparison Table is likely based on each utility's available resources, their projected resource costs, as well as their overall mix of existing and potential new resources. FBC assumes that the Preferred Resource Strategies include significantly more solar than wind and other resources because of the relatively low cost of solar energy generation for these utilities.

5.4 Why would Pacific Northwest utilities Preferred Resource Strategies include 3,485 MW of solar by 2023 compared to FBC having 0 MW of solar in any of its Preferred Portfolios before 2031?

Response:

Pacific Northwest utilities' preferred resource strategies are based on larger and earlier energy and capacity requirements as well as GHG reductions policies that are different from those of FBC. In some cases, state-mandated clean energy policies are resulting in the early retirements of higher emitting resources which are being replaced by renewables such as solar.

As discussed in Section 9.1, FBC has energy requirements earlier in the planning horizon. Based on current price forecasts, market energy and Tranche 1 PPA energy is more cost effective than other resources options, including solar. Furthermore, FBC's existing resources are primarily clean hydro generation and FBC has no intention of replacing these existing resources with solar. The large amount of clean and renewable resources being developed in the region, as noted by the question, can lead to times of surplus in the market resulting in attractive market prices.

As discussed in Section 9.2 of the Application, FBC is currently projecting no capacity resource gaps that need to be filled until 2031. Due to this, as well as market capacity for June being permitted up to 2030, no new capacity resources are required in the preferred portfolios until 2030 and later.

6.0 Topic: Comparison of Solar Procurement in Alberta.

Reference: Exhibit B-1, Sections 2.1 and 2.8.8, "Planning Environment".

Lines 15 – 17, in Section 2.1, "Introduction" state:

"Next, the supply environment is examined as the changes occurring in BC, Alberta, California and the Pacific Northwest region will influence FBC's resource options and market electricity prices."

Lines 25 – 30, in Section 2.2.8, "Summary", state:

"Energy and environmental policy in Canada and the US is constantly evolving as federal, provincial, state, and municipal governments implement initiatives to reduce GHG emissions and transition to clean energy sources. These policy actions will impact the electricity generation mix in western Canada and the US Pacific Northwest region as generators in the US and provinces like Alberta move towards greater adoption of renewable resources like wind and solar."

The National Energy Resource Laboratory map of solar PV irradiance also shows that the surface irradiance in FBC's service territory is similar to the best solar regions in Southern Alberta. Those two areas share a long-term average GHI of between 3.5 to 4.0 kWh/sq.m/day based on 19 years of satellite solar observation.

Solar Alberta's Executive Director stated, in a CBC news article, "Could this be Solar Power's Time to Shine in Alberta?" November 9, 2021:

"At first it was a bit of a slog getting solar going in Alberta, but the growth has been exponential in recent years … solar contributed 170 MW to the grid in 2020 and by the end of 2023 that number will have jumped to 4,600 MW."

Source: https://www.cbc.ca/news/canada/edmonton/solar-nait-solar-alberta- heather-mackenzie-jim-sandercock-robert-hornung-1.6235858

6.1 Please compare the median and/or range of the long-term average Global Horizontal Irradiance (in kWh/sq.m/day) in Southern Alberta with the long-term average Global Horizontal Irradiance for the subset of 11 projects in FBC's Resource Options Report.

Response:

Please refer to the response to BCSSIA IR1 5.2.

6.2 Why would Alberta Solar expect 4,600 MW of solar by 2023 compared to 0 MW for any of FBC's Preferred Portfolios up to 2031?

Response:

As discussed in Section 2.4.3.2, Alberta has outlined its intent to retire over 5,000 MW of coal-fired generating capacity[7,8] and replace this capacity primarily through coal-to-gas conversions as well as solar and wind generation as the economics of renewables become more attractive. In contrast, FBC's existing resources are primarily clean hydro generation and FBC has no intention of replacing these existing resources with solar. FBC plans to meet incremental energy requirements primarily through market energy purchases. FBC is currently not forecasting any capacity gaps until 2030.

[7] Alberta Government. Climate Change Legislation. Phasing out emissions from Coal. https://www.alberta.ca/climate-coal-electricity.aspx

[8] Canada Energy Regulator. Provincial and Territorial Energy Profiles – Alberta. Electricity section. https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-alberta.html

7.0 Topic: UEC Calculation Formula and Input Assumptions.

Reference: Exhibit B-1, Section 10.2.2, "Financial Attributes", and Appendix K – Resource Options Report, Section 3.3.3 "Utility-Scale Solar Power".

The first two paragraphs of Section 10.2.2 Financial Attributes state:

"To enable comparisons of the costs of resources that represent a wide range of technologies and fuel sources, capital and operating costs and project lifespans, the financial characteristics of the different resource options are described by two simplified cost metrics: unit capacity cost (UCC) and unit energy cost (UEC). UCC is the annualized cost of providing dependable capacity for each resource option, expressed in $ per kW-year. UEC is the annualized cost of generating a unit of electrical energy using a specific resource option, expressed in $ per MWh."

"The UCC and UEC values are based on a levelized net present value (NPV) cost basis in order to enable comparison between the different resources with different cost structures and energy and capacity values. The UECs and UCCs are presented in real 2020 dollars. FBC has assumed a WACC of 3.69 percent after tax (in real terms) as the discount rate in determining the UECs and UCCs. FBC specific adders, such as those relating to transmission wheeling costs, are also included in the UEC and UCC values."

Lines 3 – 4 on page 42 of Section 3.3.3 of Appendix K – Resource Options Report, Utility-Scale Solar Power state:

"FBC analyzed a subset of 11 solar projects ranging in nameplate capacity from 17 MW – 490 MW in its portfolio analysis."

7.1 Please show how the 3.69% WACC is calculated and describe how the basic assumptions are derived.

<u>Response:</u>

Please refer to the response to BCOAPO IR1 41.1.

7.2 Please show the detailed calculation of UEC for the following projects in Preferred Portfolio C4: Solar7 [2031], Solar1 [2033], Solar2 [2037] and Solar3 [2038].

<u>Response:</u>

To respond to this question, FBC would need to detail the cost components of individual projects. Individual project costs are considered confidential and resource costs are generally only shown in aggregate. Some of the cost components of the UEC are provided by the requested categories in the response to BCSSIA IR1 3.5.

8.0 Topic: Utility Scale Solar Cost Reductions from 2020 to 2021.

Reference: Exhibit B-1, Preferred Portfolio Reference: Executive Summary, (page ES-16), Appendix K – Supply Side Resource Option Report, Section 3.3.3.

Portfolio C3 is FBC's preferred portfolio for new generation resources for 2030 and beyond. FBC states:

"The preferred portfolio … includes a mix of PPA, market energy, battery storage, gas plants using RNG fuel, solar, wind and run of river generation." [page ES-16, pdf p.28]

Lines 3 – 5 in Section 3.3.3 Utility-scale Solar, in Appendix K – Supply Side Resource Options Report state:

"Improvements in technology as well as cost reductions for materials have contributed to the overall decrease in costs for solar PV generation. The following figure shows the decrease in the US cost for solar PV since 2009."

Figure K3-24: US Solar PV Price Trends[36]

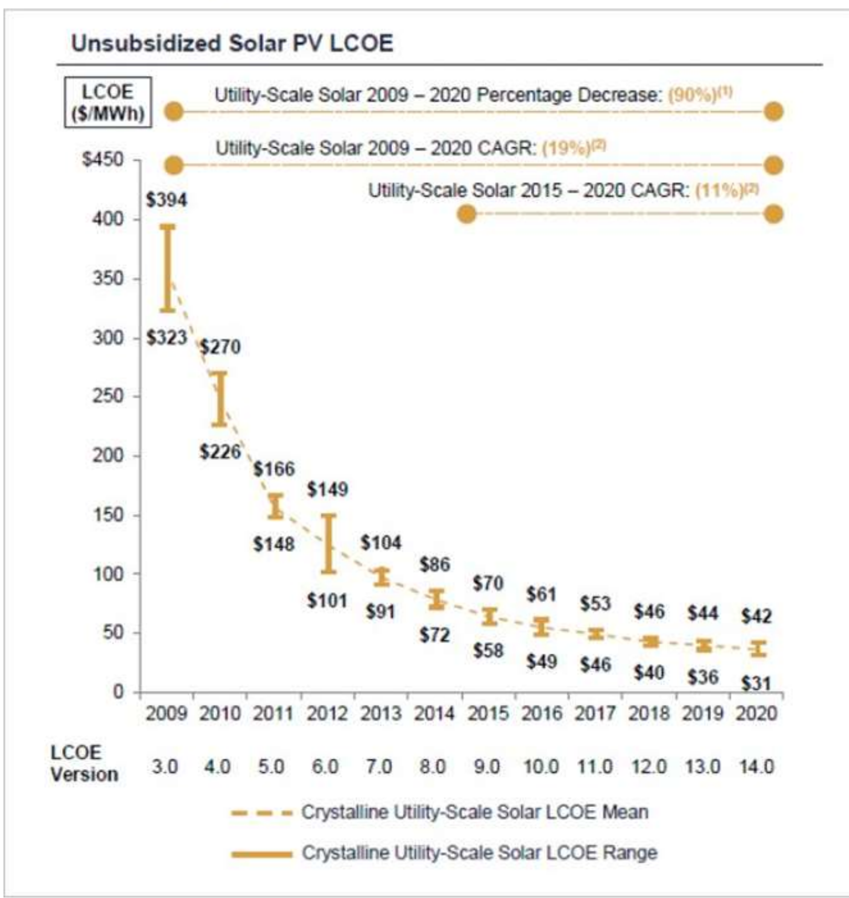


Figure K3-24 ends in year 2020.

A new report on further solar cost reductions, from 2020 to 2021, was published on November 4, 2021, after FBC filed the Application.

The National Renewable Energy Laboratory published the US Solar Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2021. Source; https://www.nrel.gov/docs/fy22osti/80694.pdf

The National Energy Resource Laboratory report shows costs reducing from 2020 to 2021. Executive Summary page v from the report states (underlining added):

"Figure ES-1 compares our Q1 2021 PV-only benchmarking results to the Q1 2020 National Renewable Energy Laboratory benchmarking analyses. Between 2020 and 2021, there were 3.3% ($0.09/W), 10.7% ($0.19/W), and 12.3% ($0.13/W) reductions (in 2020 USD) in the residential, commercial rooftop, and utility-scale (one-axis) PV system cost benchmarks respectively. Balance of system (BOS) costs have either increased or remained flat across sectors, year- on-year, unlike in previous benchmarking reports, which generally have reported declining BOS costs. The increase in BOS cost has been offset by a 19% reduction (in 2020 USD) in module cost. Overall, modeled PV installed costs across the three sectors have declined compared to our Q1 2020 system costs."

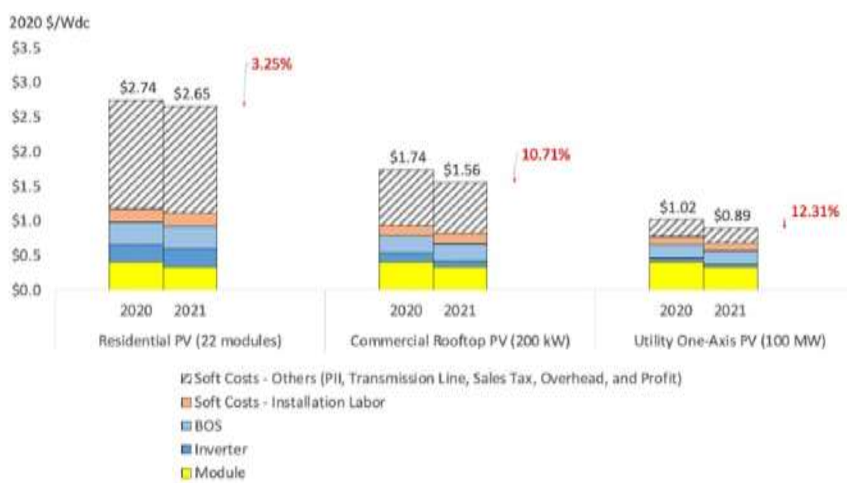


Figure ES-1. Comparison of Q1 2020 and Q1 2021 PV cost benchmarks

BOS is balance of system; PII is permitting, inspection, and interconnection.

8.1 How much would FBC's UEC for utility-scale solar drop if the PV costs dropped 12.31%, all other assumptions being the same?

Response:

If the 2020 UECs values in Table 10-2 for utility-scale solar, which range from $99 to $134 per MWh, were to drop by 12.31 percent, then the UEC range would be $87 to $118 per MWh, in 2020$. This was determined by multiplying the UEC values in Table 10-2 by 0.8769 (87.69

percent).[9] Please also refer to the response to CEC IR1 51.1 for FBC's assumed changes in generator costs for the various resource types over the planning horizon.

9 Calculated from 100 percent minus 12.31 percent.

9.0 Topic: Utility Scale Battery Energy Storage Cost Reductions from 2020 to 2021.

Reference: Exhibit B-1, Preferred Portfolio Reference: Executive Summary, page ES-16, Appendix K – Supply Side Resource Option Report, Sections 3 and 3.2.3.

Portfolio C3 is FBC's preferred portfolio for new generation resources for 2030 and beyond. FBC states:

"The preferred portfolio … includes a mix of PPA, market energy, battery storage, gas plants using RNG fuel, solar, wind and run of river generation." [page ES-16, pdf p.28]

Lines 2 – 5 in Section 3, Supply Side Resource Options, in Appendix K state:

"The following table shows the range of unit costs for the resource options that were considered. The resource options show projects of various sizes and economies of scale, so a minimum and maximum are shown as well as the average. Resources are sorted from lowest to highest unit costs."

Table K3-3: Supply-Side Resource Options Unit Cost Summary

Resource Option	UEC ($/MWh)	UCC ($kW-year)
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

Lines 10 – 12 in Section 3.2.3 Battery Storage and Distributed Batteries, in Appendix K – Supply Side Resource Options Report, states:

"The cost of battery storage has declined significantly in recent years due to improvements in technology. The following figure shows the declining unit costs for lithium-ion batteries since 2010."

Figure K3-15: Lithium-ion battery price trends[30]

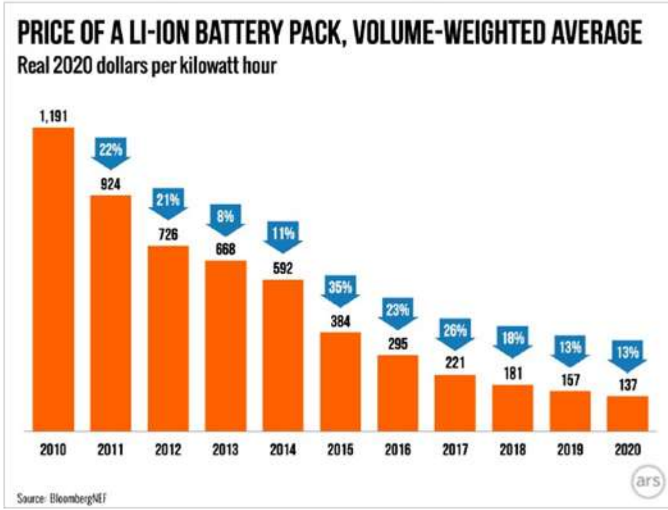


Figure K3-15 ends in year 2020.

A new report on further solar and battery energy storage systems (BESS) cost reductions, from 2020 to 2021, was published on November 4, 2021, after FBC filed the Application.

The National Renewable Energy Laboratory published the US Solar Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2021. Source; https://www.nrel.gov/docs/fy22osti/80694.pdf

The National Energy Resource Laboratory report shows BESS costs reducing from 2020 to 2021. Executive Summary page vii states:

"Figure ES-2 shows the difference between Q1 2021 and Q1 2020 benchmark values adjusted for comparison. In addition to changing the dollar year from 2019 to 2020, we adjusted Q1 2020 values to have the same size storage capacity as the current Q1 2021 sizes to better demonstrate cost changes between years."

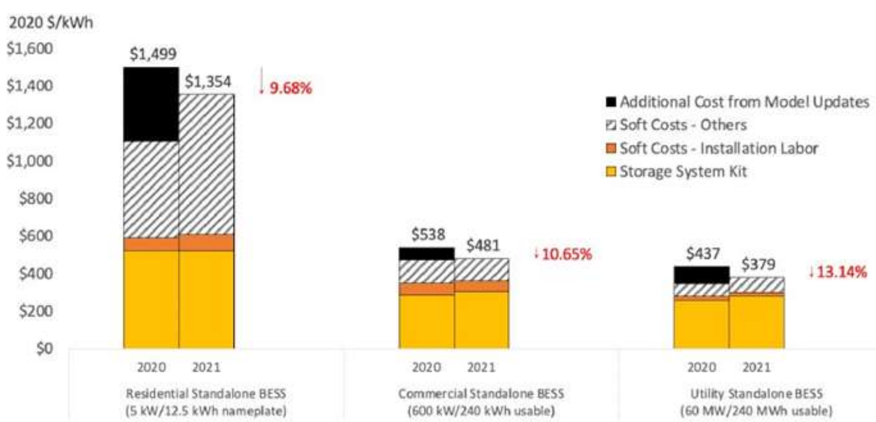


Figure ES-2. Comparison of Q1 2020 and Q1 2021 stand-alone BESS cost benchmarks

9.1 How much would FBC's UCC for battery storage drop if the BESS costs dropped 13.14%, all other assumptions being the same?

Response:

If the 2020 UCC values in Table 10-2 for battery storage, which range from $226 to $267 per kW-year, were to drop by 13.14 percent, then the UCC range would be $196 to $232 per kW-Year, in 2020$. This was determined by multiplying the UCC values in Table 10-2 by 0.8686 (86.86 percent).[10] Please also refer to the response to CEC IR1 51.1 for FBC's assumed changes in generator costs for the various resource types over the planning horizon.

[10] Calculated from 100% minus 13.14%.

10.0 Topic: FBC's Support for B.C.'s Greenhouse Gas Reduction Objectives.

Reference: Exhibit B-1, Section 1, Introduction, Table 1-3: "Applicable CEA Objectives Relevant to the LTERP", and FBC's website re Renewable Natural Gas.

In Table 1-3, in response to Clean Energy Act (CEA) Section 2(g), (page 11, PDF 41 of 852), FBC states:

"Provincial targets are not specific to individual utilities. FBC GHG emissions represent only about 0.082 percent of total provincial emissions.…

... FBC provides mostly clean electricity for EV charging which is estimated to reduce GHG emissions in BC by 0.04 million tonnes CO_2e by 2040 (see Section 2.2.6). FBC intends to provide mostly clean electricity to support the development of RNG and, if required, hydrogen production and carbon capture and storage…"

On the FBC website (at https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas#RenewableNaturalGas) FBC states:

"For more than 10 years we've teamed up with RNG suppliers, including local farms, landfills, green energy companies and municipalities, to capture that methane and purify it to make RNG. Capturing methane that would otherwise escape into the atmosphere, and using it to make renewable energy, makes RNG a carbon neutral energy source. 1

RNG is one way that is helping us meet an ambitious target to reduce our customers' greenhouse gas emissions by 30 per cent by 2030. Within this target is a goal to have 15 per cent of our natural gas supply be renewable by 2030."

10.1 FBC states that RNG is a "carbon neutral energy source." Please explain to what extent GHGs are reduced when, for every tonne of RNG that is burned, 2.75 tonnes of CO_2 will be emitted, and 2.25 tonnes of H_2O, both of which are greenhouse gases.

Response:

The GHG emissions cited in the preamble allude to an emissions factor for RNG of approximately 50 kg CO_2e per GJ, which is the emissions factor associated with conventional natural gas and is therefore incorrect for the characterization of RNG. Emissions associated with RNG combustion are estimated to be 0.2932 kg CO_2e per GJ,[11] or essentially carbon neutral.

[11] 2020 B.C. Best Practices methodology for Quantifying Greenhouse Gas Emissions, published the BC Ministry of Environment and Climate Change Strategy, Page 8.

Existing BC Government policy considers RNG (i.e., biomethane) captured from organic waste (including agriculture, landfill, or wastewater sources) to be a carbon-neutral fuel source.[12,13,14] In this context, carbon-neutral status means that both combustion and life-cycle emissions do not contribute any net carbon dioxide emissions to the atmosphere. The CO_2 generated from combustion of RNG is considered to be biogenic, or non-additive to atmoshperic carbon.

RNG produced via anaerobic digestion processes contributes to GHG savings through reduced methane emissions, displacement of fossil fuels, reduced fertilizer use, and in some cases, direct use of the CO_2 produced. The biomethane is produced as organic material is broken down by bacteria (anaerobic decomposition) and would be generated regardless of any human intervention. As stated in the IR preamble above, RNG provides the additional benefit of capturing and upgrading this methane, which would otherwise be released into the atmosphere, for use as a renewable fuel that displaces conventional natural gas.

Furthermore, in the absence of a project that captures and uses this methane, it would have otherwise been released into the atmosphere adding to global warming impacts. The global warming potential, or “atmospheric heating equivalency”, of methane and carbon dioxide, which is the main greenhouse gas constituent emitted from the combustion of methane, is stated in the 2020 BC Best Practices Methodology for Quantifying Greenhouse Gas Emissions[15] as 25 and 1, respectively. In simple terms, this means that each molecule of methane has 25 times heat trapping potential as one molecule of CO_2. Utilizing RNG for heating and other purposes converts biomethane to carbon dioxide, preventing it from directly entering the atmosphere, thus reducing overall greenhouse gas emissions.

From a lifecycle perspective, the emissions savings from displacing conventional natural gas production with RNG far outweigh biomethane production emissions. The expected greenhouse gas sinks in the biomethane life cycle that reduce greenhouse gas emissions include:

1. Methane capture and destruction from landfill gas, manure management, and wastewater treatment. Under baseline conditions, organic material would typically decompose and release methane directly into the atmosphere;
2. Avoided emissions from the combustion of conventional natural gas; and
3. Avoided life cycle emissions from the extraction and processing of natural gas.

12 https://www2.gov.bc.ca/assets/gov/taxes/sales-taxes/publications/ct-001-natural-gas-biomethane-sellers.pdf

13 http://www.energybc.ca/cache/biofuels/www.energyplan.gov.bc.ca/bioenergy/PDF/BioEnergy_Plan_005_0130_web0000.pdf#:~:text=The%20BC%20Bioenergy%20Strategy%20sets%20us%20on%20a,into%20bioenergy.%20Bioenergy%20provides%20new%20opportunities%20for%20agriculture

14 https://bcbioenergy.ca/wp-content/uploads/2011/07/Bioenergy-Guide-2010-final-updated-May-2011.pdf

15 https://www2.gov.bc.ca/assets/gov/environment/climate-change/cng/methodology/2020-pso-methodology.pdf

10.1.1 What does FBC assume to be the atmospheric heating equivalency of the methane if it were to escape in its raw form, compared to the heating equivalency of the eventual combustion products from the RNG?

Response:

Please refer to the response to BCSSIA IR1 10.1.

10.1.2 What is the definition of carbon neutrality?

Response:

Please refer to the response to BCSSIA IR1 10.1.

10.2 FBC states that it has an "ambitions target to reduce our customers' greenhouse gas emissions by 30 per cent by 2030".

10.2.1 Please provide FBC's analysis of its customers' GHG emissions as of 2007, by customer type.

Response:

FortisBC's 30BY30 target applies to both the electric (FBC) and gas (FEI) utilities. However, this IR response only applies to FBC.

It is not possible to estimate and provide the analysis of FBC's customers' GHG emissions as of 2007 by customer type, since the utility's GHG emissions were not being reported at that time. Nevertheless, FBC's customers GHG emissions are believed to be not significant, considering that the electricity delivered by FBC to its customers was and continues to be primarily generated from renewable sources, particularly from hydroelectric resources.

10.2.2 What different programs or initiatives does FBC have that are going to enable its customers to achieve this 30% reduction by 2030?

Response:

FortisBC's 30BY30 target applies to both the electric (FBC) and gas (FEI) utilities. Most of the expected 30 percent reduction in GHG emissions is expected to be achieved by FEI, rather than FBC. For the purposes of this response, only initiatives applicable to FBC are discussed below.

The most significant GHG emission reductions directly supported by FBC relate to EVs and EV charging infrastructure. As discussed in Section 2.2.6 of the Application, FBC will be helping its customers (mainly residential and commercial customers), reduce their transportation GHG emissions by providing them with the necessary EV charging infrastructure and incentives to allow them to charge their EVs at home, business or through FBC's EV charging station network, all of which are supplied by clean electricity. These initiatives and programs are expected to reduce GHG emissions in BC by 0.04 million tonnes CO2e annually by 2030.

FBC has also significantly increased investments in conservation and energy efficiency incentives and rebates to help its residential, commercial, and industrial customers reduce and manage their energy consumption. As FBC's electricity supply is primarily hydro-based and results in essentially no GHG emissions, there are no forecast GHG emission reductions relating to FBC's conservation and energy efficiency incentives. However, improved energy efficiency for electricity consumers will allow the existing supply of clean electricity to be applied to more uses, including FEI's renewable gas projects. As such, FBC will indirectly support FEI in its effort to decarbonize the gas network by providing the necessary clean electricity to enable renewable natural gas and hydrogen and/or carbon capture projects within FBC's territory. FEI's investment in renewable gases will play a significant role in achieving the 30BY30 target. However, the GHG emission reduction estimates associated with these initiatives are allocated to FEI, rather than FBC, as they help FEI's customers reduce their GHG emissions (and so there is no estimated GHG emission reduction allocated to FBC).

10.2.3 Does FBC have a residential or commercial electricity rate that will incentivize its customers to convert to electric vehicles, and to encourage them to shift the charging of those vehicles to off-peak hours? If not, why not, and is there such a rate being planned?

Response:

FBC does not have a residential or commercial rate specifically for EV charging, in part due to a lack of load data upon which to design the rate. In the absence of meaningful data, it is not clear whether the load characteristics of EV charging warrant a different rate.

However, due to the flexible nature of many EV charging loads, FBC is exploring technologies and programs to incent customers to shift the charging of EVs from peak hours, as discussed in Section 2.3.2 of the Application.

Also, FBC is preparing an application for providing incentive funding for light-duty fleet charging infrastructure as noted in the response to BCSEA IR1 7.2.

10.2.4 Is FBC offering incentives or rates to encourage residents and businesses to convert heating to electric heat pumps, or even to supplement gas-fired heating with heat pumps? If not, why not, and are such incentives or rates being planned?

Response:

FBC provides incentives for residential and commercial customers to replace less-efficient electric resistive heating systems, such as electric baseboards, with retrofitted electric heat pumps.

FBC does not currently provide incentives or special rates to convert other heating equipment to electric heat pumps or to supplement gas-fired heating with heat pumps (fuel-switching incentives). However, FBC administers the provincial government's CleanBC fuel-switching incentives for FBC customers and the municipal electricity customers of Summerland, Penticton, Grand Forks, and Nelson Hydro. FBC has focused on providing energy efficiency incentives and has not offered fuel-switching incentives as they are not cost-effective (per the Total Resource Cost test) under the *Demand-Side Measures Regulation*.

However, FBC is currently undertaking an electrification study, the results of which will inform potential future fuel-switching incentives or special rates that could be offered outside of FBC's DSM program.

10.2.5 Please provide FBC's summary analysis of the expected 30% GHG reductions that it will enable its customers to achieve by 2030, by customer type, and broken down by which of its programs will be enabling those reductions. (I.e., how much GHG reduction is FBC forecasting to result from RNG, or EV charging, or other initiatives which cause fuel switching from fossil fuels to clean electricity, and for which customers?)

Response:

Please refer to the response to BCSSIA IR1 10.2.2.

11.0 Topic: BC Carbon Price Scenarios.

Reference: Exhibit B-1, Section 2.5.4, Figure 2-20: BC Carbon Price Scenarios (page 75, PDF 105 of 852).

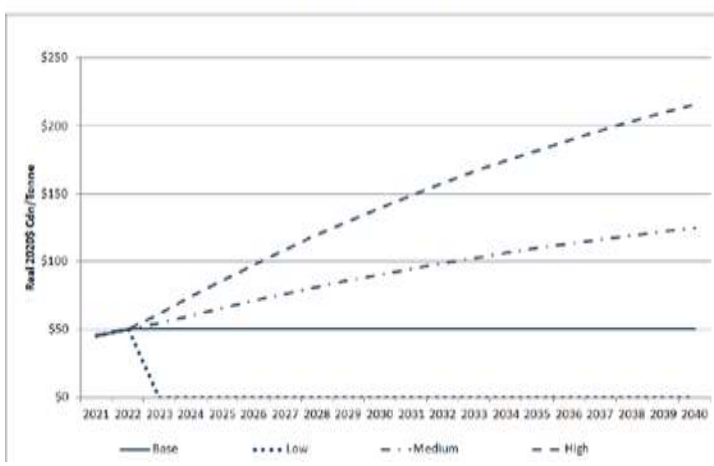
FBC states (page 74, PDF 104 of 852): [emphasis added]

In December 2020, the Canadian federal government announced 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. The price would rise by $15 per tonne per year for eight years beginning in 2023 to reach $170 per tonne in 2030.120 This carbon tax increase has not yet been enacted into legislation and, if it is, it is uncertain how BC will incorporate this into its own carbon tax plans.

FBC has developed its carbon price scenarios based on this information. 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. 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 also included a high case*** *based on the assumption of annual increases of $15 per tonne (in nominal terms) and reaches $140 per tonne (real terms) in 2030, which is equivalent to $170 per tonne*

FBC displays these Carbon Price Scenarios in Figure 2-20

Figure 2-20: BC Carbon Price Scenarios



11.1 Is it true that, in Figure 2-20, the “High” Scenario represents the current agenda of the federal and provincial governments to $170 by 2030?

Response:

FBC confirms that the High Scenario includes the assumption that carbon prices will reach $140 per tonne (in real terms), which is the equivalent to the federal and provincial governments' plan to have carbon prices reach $170 per tonne (in nominal terms) by 2030. The price forecast beyond 2030 continues to increase at the annual rate of $15 per tonne (in nominal terms).

11.2 Which Scenario has FBC used in its reference case load forecast?

Response:

FBC's carbon price scenarios are not used as inputs for the Reference Case load forecast but, as discussed in Section 2.5, are inputs into the cost of gas-fired generation. FBC has used the base case carbon price forecast as its base portfolio characteristic for the purposes of the portfolio analysis presented in Section 11.1.1. FBC has used the high carbon price case as a sensitivity case.

11.3 What elements of FBC's forecasts would be changed by assuming the High Scenario? What would be the impact on the Load Forecast?

Response:

No other elements of FBC's price or load forecasts would be changed by assuming the high case carbon price scenario. As discussed in Section 2.5, the carbon price scenarios are primarily inputs into the cost of gas-fired generation resource options. The cost of carbon could also influence the cost of market purchases if FBC were unable to purchase a clean market adder and market import power were to become subject to carbon taxes in the future.

12.0 Topic: Climate Change

Reference: Exhibit B-1, Section 2, Planning Environment, Section 2.2.1, Climate Change (pages 18-21, PDF 48 of 852).

At page 18 FBC states:

"… 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 pattern will occur over the next century…

While the figures relate to average warming temperatures over time, they do not capture the increase in the weather and temperature volatility that has occurred in recent years and which is expected to continue into the future."

At page 21 Fortis states:

"…Any changes to water availability for hydroelectric generation in the Pacific Northwest could open up the possibility of changes to the entitlements under the Canal Plant Agreement (CPA), thus impacting FBC's existing supply of power…".

12.1 What studies has FBC carried out to determine the impact of the increased weather volatility on its supply of electricity including but not limited to droughts of the type that occurred in British Columbia in the early 1940's that BC Hydro formerly used as its critical water sequence? Have historical droughts of a longer duration than this period been identified by tree ring, lake sediment or other analysis? If yes please provide the corresponding analysis.

Response:

FBC has not carried out specific studies to determine the impact of the increased weather volatility on its supply of electricity including the types of droughts discussed in the question. Therefore, FBC does not know if historical droughts of a longer duration than this period have been identified by tree ring, lake sediment or other analysis. Under the CPA with BC Hydro, FBC is not subject to annual variations in the water supply but receives an average year energy entitlement.

12.2 What studies is FBC aware of that have been carried out on the topics described in IR 12.1 that have been carried out by third parties? Please provide these studies and FBC's comments on them.

Response:

FBC's LTERP references a recent study that indicates rising temperatures and changes in precipitation pattern will occur over the next century, including Canada's Changing Climate Report, Government of Canada (2019).[16] Please also refer to the response to BCSSIA IR1 12.3 for links to, and FBC's commentary on, the climate change studies and reports reviewed in developing the LTERP.

12.3 What studies is FBC aware of that have been carried out on increased weather volatility and/or climate change such as the impacts of longer and more severe drought on the production of electricity including hydroelectricity in the Columbia basin in Canada and the U.S. Please provide these studies and FBC's comments on them.

Response:

FBC considered the following climate change studies and reports in developing Sections 2.3 and 2.4 of the Planning Environment and Section 5.0 for the impact to existing supply-side resources. In general, FBC's comments on climate change impacts to hydroelectricity in the Columbia basin in Canada and the US are stated in Section 5.1.1 as follows at page 114:

> *"…climate change may result in more precipitation as rain instead of snowpack during the winter months, which would change the monthly profile and availability of water flow, potentially leading to an earlier freshet period and decreased flows during the summer as well."*

> *"In addition, it is not known how potential changes to the Columbia River Treaty (CRT) between Canada and the United States might impact FBC CPA entitlements. While the CRT will not directly impact FBC CPA entitlements since Kootenay Lake is outside the CRT, indirect impacts may be possible… Depending on the nature of what modifications may be required, there may or may not be a risk to FBC entitlements."*

Reference Studies and Reports:

Canada's Changing Climate Report, Government of Canada, 2019, URL:

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

Nature Geoscience, Projected deglaciation of western Canada in the twenty-first century, April 2015, URL:

https://www.researchgate.net/publication/275057821_Projected_deglaciation_of_western_Canada_in_the_twenty-first_century

BC Climate Action Secretariat, Preliminary Strategic Climate Risk Assessment for British Columbia – Summary of Results, July 2019, URL:

https://www2.gov.bc.ca/assets/gov/environment/climate-change/adaptation/prelim-strat-climate-risk-assessment.pdf

BC Hydro, How B.C.'s generation system is adapting to extreme weather and unforeseen events, April 2019, URL:

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/news-and-features/report-generational-challenge--bcs-generation-system.pdf

BGC, High Level Assessment of a Proposed Dam, November 2020, URL:

http://www.llbc.leg.bc.ca/public/pubdocs/bcdocs2021/721526/721526_19Nov2020_Koocanusa_Reservoir_Dam_Final_DRAFT.pdf

U.S. Department of the Interior, West-Wide Climate Risk Assessment – Columbia River Basin – Climate Impact Assessment, March 2016, URL:

https://www.usbr.gov/watersmart/baseline/docs/cbia/ColumbiaBasinImpactAssessment.pdf

Columbia River Treaty, Local Government's Committee Recommendations Update, January 2021, URL:

https://akblg.ca/src/documents/Columbia%20River%20Treaty/CRT%20LGC%20Recommendations%20January%202021%20FINAL.pdf

Columbia River Treaty, 2014/2024 Review, July 2010, URL:

https://engage.gov.bc.ca/app/uploads/sites/6/2012/04/Phase1StudyandExecSummary.pdf

12.4 In view of the potential impacts of increased weather volatility and/or climate change, why is FBC not seeking to diversify its supplies of electricity by for example acquiring more electricity from solar generation?

Response:

FBC is seeking diversity in its supply of electricity in this LTERP by including several different types of resource options, including solar generation, in its preferred portfolios.

13.0 Topic: The Value of Pumped Storage and Batteries.

Reference: Exhibit B-1, Section 10.3, Resource Options Evaluation", Table 10-2: Supply-Side Resource Options Unit Cost Summary (page 166, PDF 196 of 852).

FBC summarizes the UECs and UCCs of its various Resource Options as follows:

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

Resource Option	UEC ($/MWh)	UCC ($kW-year)
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

Regarding the UECs and UCCs for Pumped Hydro Storage and Battery Storage, FBC states:

"… 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."

"… there is little incremental energy produced (or negative net energy in the case of pumped storage hydro or battery storage), creating a high UEC."

13.1 Where would the pumped storage be located that has a minimum capacity of 1000 MW? Why are smaller units not considered for that location?

Response:

The pumped storage hydro resources considered in the LTERP are located in BC Hydro's service territory. Specific location details are considered confidential information.

As shown in Figure 10-2, the UCC of pumped storage hydro has the greatest size range of all capacity based resources, with the larger 1000 MW projects being more cost effective than the smaller pumped storage hydro projects. The largest possible pumped storage hydro project for a specific site location was assumed to capture the economies of scale associated with this resource type. Pumped storage hydro facilities require a geologic formation consisting of two large reservoirs with sufficient elevation differential between them. Such formations are rare, or tend to be found in remote off-grid locations in mountainous regions where construction can be difficult. It may be possible to develop a smaller pumped storage hydro project at a location identified for a larger project, but many costs of developing a pumped storage hydro facility do not scale well.

13.2 Although pumped storage and battery storage may not produce net energy – since they use energy to produce energy – they can exchange low value or surplus energy for higher value needed energy. How is the value of this time shifting of energy production included in the evaluation of these resources?

Response:

Please refer to the response to CEC IR1 44.2.

13.3 Please provide the analyses that gave rise to the UCCs for Pumped Hydro Storage and Battery Storage in the above Table 10-2.

Response:

The UCCs of pumped hydro storage and batteries were developed using cost data from the BC Resources Options Report. Detailed calculations for the UCCs for individual projects is considered confidential information.

14.0 Topic: Transmission Constraints.

Reference: Exhibit B-1, 2021 LTERP, Section 10, Supply Side Resource Options, subsection 10.4, Market Purchases, (page 170, PDF 200 of 852)

On page 170 FBC states:

"... 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."

14.1 Please provide the complete details of the constraints on Line 71 including Teck and US transmission south of the border.

<u>Response:</u>

In order to access US market supply, FBC must have transmission in order to:

1. Transmit power from the source in the US to the BC/US border;
2. Cross the border (Path 3); and
3. Move the power from the border to FBC's system.

FBC does not hold any firm rights on US transmission south of the border, but can gain access to this transmission via its CEPSA Agreement with Powerex, contingent on Line 71 availability. FBC does hold transmission rights on Teck Metals Ltd.'s (Teck) Line 71, which provides transmission both across the BC/US border and to the FBC system. However, as described in the Application in Section 5.6, page 118, FBC's rights to 71L will terminate at some point. FBC will be considering replacement transmission options as part of the more detailed work to be completed in examining generation options as described in the response to BCUC IR1 31.18.1

Constraints on any of these transmission paths could interrupt supply, and those constraints could be due to either congestion or transmission line outages. Congestion might be the result of either physical or contractual limitations. Physical congestion is caused by limits on actual energy flows on lines or paths. Contractual congestion is driven by transmission rights and the availability of transmission capacity in the market. Transmission line outages can result from many causes such as, but not limited to, equipment failures, maintenance, wildfire, weather, human-error, and power system conditions.

14.2 Does FBC have any other access to US market supply through BC Hydro or otherwise? If yes, please provide the details.

Response:

FBC has no other firm access to US market supply through BC Hydro or otherwise. However, in the absence of Line 71 access, FBC could endeavor to reserve transmission[17] from the US to the BC/US border via Bonneville Power Administration (BPA), and across the BC/US border to FBC's system via BC Hydro. These transmission reservations would be subject to availability as posted on the Open-Access Same-Time Information System (OASIS) by BPA and BC Hydro and are subject to the same risks as noted in the response to BCSSIA IR1 14.1. In addition, the majority of the firm transmission rights on Path 3 (across the US/BC border) are fully subscribed and cannot be secured over the long term.

14.3 If FBC has any other access to US market supply, is this access similarly constrained by constraints on US transmission south of the border? If yes please provide the details.

Response:

Please refer to the response to BCSSIA IR1 14.2.

[17] It is unlikely that FBC would attempt to secure transmission reservations itself, but would instead rely on the services of a power marketer to do so.