Diane Roy
Vice President, Regulatory Affairs

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

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

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

April 6, 2017

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)

Project No. 3698896

2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan)

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

On November 30, 2016, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-197-16 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact Joyce Martin at 250-368-0319.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-1-1, page 8, Table 1-3

Table 1-3: Applicable *CEA* Objectives Relevant to the LTERP

Section of the *CEA*	*CEA* Objective	How LTERP Supports Objective
2(a)	To achieve electricity self-sufficiency.	FBC interprets this to mean using generation resources located within B.C. Self-sufficiency requirement by 2016 for BC Hydro; other utilities must consider this objective. FBC's supply is currently sourced mainly from within B.C. and market purchases are not recommended in the long term (see Section 9).
2(b)	To take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%	The 66 percent target applies to BC Hydro. FBC has assessed DSM scenarios and voluntarily adopted a target of 66 percent for 2018-2020 then ramping up to 80 percent by 2023 based on the LT DSM Plan.
2(c)	To generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity	Requirement to take actions to meet this target applies to BC Hydro or a prescribed utility. FBC-owned resources and long-term contracts are hydro-based. BC Hydro resources are currently 98 percent clean.[4] FBC alternative and preferred portfolios include clean or renewable resources.
2(d)	To use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources	FBC's LT DSM Plan provides support for energy conservation and efficiency including the use and development of innovative technologies and the LTERP portfolio analysis includes clean or renewable resources.
2(e)	To ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers	Specific to BC Hydro. FBC ratepayers are indirect customers of BC Hydro and receive the benefits of BC Hydro heritage assets via the PPA (see Section 2.2.1.2).
2(f)	To ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America	Specific to BC Hydro. FBC strives to provide cost-effective, secure and reliable service for its customers while also meeting other LTERP objectives.

1.1 Please confirm that FBC has not been explicitly directed to achieve self-sufficiency.

Response:

Confirmed. The self-sufficiency objective is a consideration, rather than a requirement, for FBC.

1.1.1 If not confirmed, please provide the direction.

Response:

Please refer to the response to CEC IR 1.1.1.

1.2 What were the driving factors that led FBC to voluntarily adopt a target of 66% to meet expected increases in the demand for electricity with DSM for the period 2018-2020?

Response:

FBC is seeking to balance the planning requirements, specified under s. 44.1(2) of the *UCA*, by increasing (b) "*by taking cost-effective demand-side measures*" in order to reduce (c) "*the demand for energy the public utility expects to serve after it has taken cost-effective demand-side measures*".

1.3 What were FBC's key objectives in ramping up its DSM target to 80% by 2023?

Response:

Please refer to the response to CEC IR 1.1.2.

1.4 If FBC could achieve cost effective DSM up to 100%, would FBC do so?

Response:

No, FBC opted not to select the Max DSM scenario that escalated to 100 percent load growth offset due to measure costs that exceeded the LRMC and poor fit in regards to the LRB monthly energy requirements.

1.4.1 Please explain why or why not.

Response:

Please refer to the response to CEC IR 1.1.4.

1.5 What proportion of FBC's energy is considered 'clean'?

Response:

Please refer to the responses to BCUC IR 1.31.1.

1.6 Does the fact that FBC ratepayers are 'indirect' customers of the authority mean that there is no CEA objective for FBC ratepayers to receive the benefit of heritage assets? Please explain why or why not.

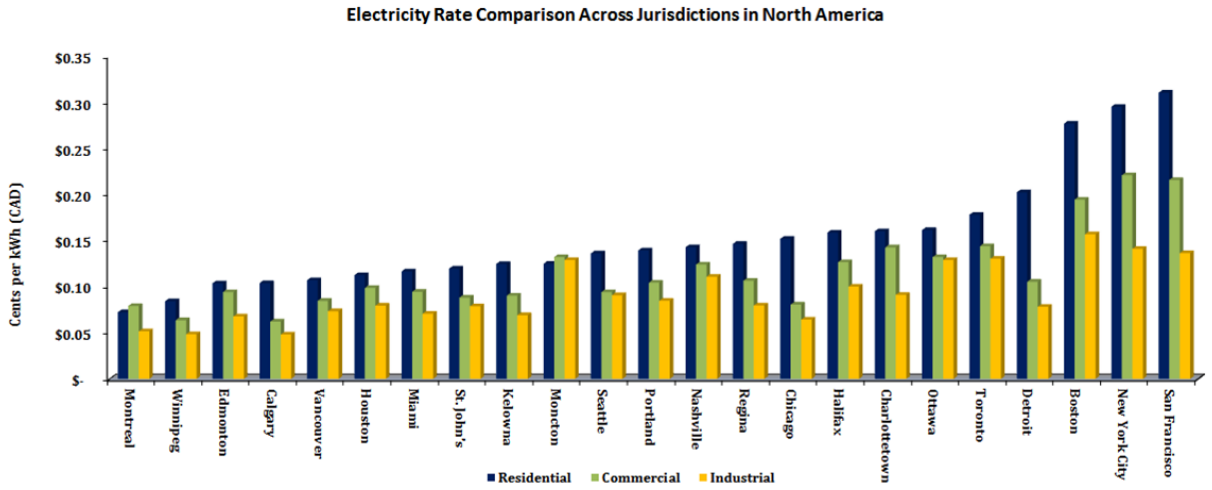
Response:

No. The *CEA* ensures that power from BC Hydro's heritage assets and B.C.'s affordable rates are protected for British Columbians. FBC's customers receive the benefits of the BC Hydro heritage assets through the PPA (as discussed in Section 2.2.1.2 of the LTERP).

1.7 Please confirm that FBC rates are among the most competitive of rates charged by public utilities in North America. Please provide evidence to support the answer.

Response:

Confirmed. The 2016 Edition of Hydro Quebec's Comparison of Electricity Prices in Major North American Cities[1] includes a comparison of the monthly electricity bills for residential customers using 1,000 kWh per month in 22 major cities across North America at April 1, 2016. An FBC residential customer with average usage of 1,000 kWh per month paid approximately $125 on April 1, 2016, which is in line with the major cities with the lowest rates shown in the report. The information from the report, showing FBC as "Kelowna" is included in the figure below.



[1] http://www.hydroquebec.com/publications/en/docs/comparaison-electricity-prices/comp_2016_en.pdf

2. Reference: Exhibit B-1, pages 27 and 28

> ***2.3.3.1 Community Solar***
>
> Solar costs fall as the size of an individual installation increases, all else equal. As a result, there is a growing interest in "community solar", in which the output of a larger solar array is divided between a number of customers.
>
> For many FBC customers, the ownership, as well as placement and operation of solar PV system, are not desirable or feasible. Customer ownership and operation requires upfront capital costs, as well as ongoing expenses associated with system operation and maintenance. Beyond cost considerations, rooftop or ground-mounted solar installations are feasible only for certain property owners. Customers who live in rental properties, multi-unit residential buildings (MURBs), or townhomes are necessarily limited in their options. Other customers that have aging rooftops, or an unsuitable rooftop orientation may also be unable to install a PV system.
>
> The Company is interested in helping customers interested in solar generation (and potentially other forms of distributed generation), but who have limited access to capital or who are not willing or able to install solar panels on their home. FBC is examining options that would allow participating customers to pay for the additional revenue requirement of community solar in exchange for a share of the solar output and is considering filing an application for a pilot program in late 2016 or early 2017.

2.1 What options are FBC examining that would allow participating customers to pay for the additional revenue requirement of community solar in exchange for a share of the solar output?

Response:

FBC anticipates that it will submit an application to the Commission for approval to construct the solar pilot project and for the accompanying rate structures in 2017. It is premature to file details of the cost recovery proposals being considered for that application in this process. FBC can confirm that the project is not yet underway; FBC will not proceed without Commission approval.

The output of the potential community solar project is not included in any portfolio considered in the LTERP and is not expected to be material.

2.2 How will the costs of this program be recovered?

Response:

Please refer to the response to CEC IR 1.2.1.

2.3 Will the fixed costs for this user group be recovered from the ratepayers as a whole? Please explain and provide quantification.

Response:

Please refer to the response to CEC IR 1.2.1.

2.4 Is a pilot project underway as of yet?

Response:

Please refer to the response to CEC IR 1.2.1.

2.4.1 If yes, please provide a brief overview of the project including its time frames, objectives and expected outcomes and costs.

Response:

Please refer to the response to CEC IR 1.2.1.

3. Reference: Exhibit B-1, page 28

2.3.4 Rate Design Considerations

The emerging technologies described in the previous sections have the potential to change the manner in which the Company interacts with its customers. By extension, this may impact whether the rates FBC has in place are able to appropriately reflect changes in how customers use power.

FBC's practice is to allocate costs to customer rate classes on the basis of cost-causation and not simply with regard to the end use of the power. That is, rates are typically designed such that the revenues collected from a rate class will recover the costs that have been allocated to it, within a range of reasonableness. 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. In this way, 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. In the near term, FBC will monitor emerging market trends and consider new or amended rate structures as part of a future rate design process.

The Company does however have a small number of current or pending programs that may require new rates, or amendments to current rates within the next few years.

First, as discussed above, FBC is examining options for a solar pilot project in 2017 in response to customer interest in renewable generation and to gather information and insight into the location of such an installation in the service area.

Second, the growth in interest and participation in small scale customer-owned generation, such as the installations that qualify for the Company's Net Metering Program, may begin to pose rate stability challenges for all customers. While the current participation rates and installed capacity are not a cause for concern, FBC recognizes that a proliferation of grid-connected customers with greatly reduced, zero, or periodic load is problematic for the current regulatory model where the costs of providing all aspects of service are recovered primarily through volumetric rates. FBC, like many other utilities, is concerned that the result of the widespread installation of customer-owned generation will be the transfer of costs to customers who either cannot participate, or choose not to participate. These concerns have led utilities and regulatory bodies in other jurisdictions to explore solutions such as residential demand charges or higher fixed charges that better reflect the fixed costs of providing service. FBC intends to explore this potentiality in its next rate design process.

3.1 When does FBC expect to file its next Rate Design Application?

Response:

FBC expects to file a Cost of Service Analysis (COSA) and Rate Design Application (RDA) in the fourth quarter of 2017.

3.2 At what levels of participation in small scale generation does FBC believe that rate stability or other challenges will arise? Please quantify.

Response:

Please refer to the response to Shadrack IR 1.3i. The Company has not identified a specific level of participation at which the transfer of costs would become unacceptable.

3.2.1 When would FBC expect to reach this level of participation?

Response:

Please refer to the response to CEC IR 1.3.2.

3.3 To the extent that net metering or future programs (such as the solar program) are already in existence or planned, are customers contributing or expected to contribute their full cost of service? Please explain and provide quantification of costs not covered and a cost of service ratio if available.

Response:

FBC can respond with respect to the existing net metering program and to its current intentions for the prospective community solar project. Any other future programs (for which FBC has no plans at the present time), will require consideration during planning.

In administering the net metering program the Company incurs some costs that are not recovered from program participants and are recovered from customers generally. These costs are related to incremental manual billing processes as well as the application and account review conducted prior to interconnection. The cost of purchasing the net excess generation from some net metering customers, which is higher on a per kWh basis than alternate sources of supply, is also a cost that is shared by other customers.

For the community solar project, FBC's planned rate design will collect all direct capital and operating costs only from program participants. It is expected that incremental customer service costs such as those mentioned above will also be incurred which will be collected from all customers consistent with net metering.

4. Reference: Exhibit B-1, page 40 and page 79

> A further key consideration for FBC is the transmission transfer limit at the three interconnections on the B.C./United States border[57] and at the two interconnections on the B.C./Alberta border. These transmission interconnections often operate at their maximum available transfer limits; therefore wheeling additional power between utilities in the region is frequently impossible. It should be noted that FBC has no transmission facilities that connect directly with markets outside of B.C. Accordingly, FBC is dependent on the availability of adequate third-party transmission capacity to serve its customers' needs, putting at risk the long-term reliable availability of wholesale market electricity to serve its growing demand. However, market energy and capacity is expected to remain adequate through the short to medium term. This is particularly true if the CEPSA agreement with Powerex is assumed to continue. On a longer term basis, market capacity and transmission availability are expected to continue to tighten and therefore FBC may not be able to rely upon them, but sufficient supply of market energy will likely be available.
>
> FBC access to the market is mainly through its transmission rights on Teck's 71 Line, which provides transmission both across the B.C./U.S. border and to the FBC system. For long-term planning purposes such as the 2016 LTERP, this access is treated as firm but it must be recognized that the Company does not own the line. Also, additional U.S. transmission is required to access the Mid-C trading hub, which is located along the Columbia River on the border between Washington and Oregon. Additional firm transmission cannot be reliably obtained on the U.S. side of the border and as such, while the market remains an excellent source of energy to meet FBC customer requirements and could meet the relatively small energy gaps that the Company expects through 2035, it cannot be considered a long-term resource to meet capacity requirements (as described in more detail in Section 8.2.4). The Company intends to continue to explore what B.C.-based market options may be available to meet future needs.

4.1 What are the interconnection limits at the five connection points to BC Hydro's system?

Response:

Each interconnection acts as one path. The three physical connections at the B.C./U.S. border is one path (Path 3), and the two physical connections at the B.C./Alberta border is considered another path (Path 1). The limits at each path can be different in each direction. The B.C. to Alberta path has a maximum rating of 1,200 MW. The Alberta to B.C. path has a maximum rating of 1,000 MW. The B.C. to U.S. path has a maximum rating of 3,150 MW, and the U.S. to B.C. path has a maximum rating of 2,000 MW.[2] While these are the maximum path ratings, actual available transmission in any hour can often be less. Specifically, although the B.C. to

[2] https://www.wecc.biz/Reliability/TAS_PathReports_Combined_FINAL.pdf

U.S. path has a rating of 3,150 MW, it is important to note that operating constraints in the Pacific Northwest often limit it to 2,400 MW or less.

4.2 Please provide accessibility data for each interconnection point for the past 5 years, including frequency and duration of the times in which wheeling becomes impossible. Please ensure that time of day, weekly, monthly and seasonal variations can be determined from the data provided.

Response:

The actual scheduled data between the B.C. and Alberta interconnection, and between the B.C. and the U.S. interconnection, can be found on BC Hydro's website, which has been replicated in the excel sheet provided in Attachment 4.2.[3] However, in order to complete the requested analysis, FBC would require data on the available transmission capacity in each hour, prior to the hour, and any amount of transmission that could have been available to purchase prior to the hour on the Open Access Same-time Information System (OASIS) transmission reservation system. FBC does not have this data, nor is it publically available and therefore FBC cannot complete the requested analysis. Without this data, simply looking at the actual scheduled flows cannot provide a reasonable analysis of congestion on either interconnection.

4.3 How much power has FBC imported through each interconnection point – by month, for the last 5 years?

Response:

The following table shows FBC's market purchases by source (B.C., U.S., Alberta) for each month over the past five years.

[3] https://www.bchydro.com/energy-in-bc/our_system/transmission/transmission-system/actual-flow-data/historical-data.html

Purchase from BC (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2012	21,338	23,009	10,102	804	1,956	4,378	16,044	4,342	8,524	9,113	9,736	325	109,671
2013	8,754	5,135	973	2,297	6,807	3,023	10,706	2,562	7,234	1,426	14,123	3,254	66,294
2014	7,449	4,781	1,880	10	6,515	7,710	6,321	4,116	515	7,643	10,698	3,890	61,528
2015	2,070	6,580	11,240	60	165	2,377	4,398	415	16,325	25,481	17,006	13,375	99,492
2016	19,946	4,150	584	267	505	8,011	548	1,112	-	5,333	119	10,138	50,713
Purchase from Alberta (MWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2012	-	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchase from US (MWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2012	23,733	30,847	30,053	27,958	21,413	26,774	25,564	12,806	34,731	38,581	32,062	56,860	361,382
2013	64,023	31,654	54,387	13,423	26,102	11,957	15,478	19,029	49,736	42,321	86,634	50,005	464,749
2014	31,968	41,892	32,034	5,304	14,552	23,205	9,636	3,210	5,220	17,350	26,211	20,028	230,610
2015	21,800	30,562	21,566	1,390	25	14,113	10,805	60	1,960	7,568	37,350	20,160	167,359
2016	15,200	26,100	34,085	8,480	-	25	160	10	15	44,067	50,777	40,392	219,311

4.4 What, if any, has been the economic impact to FBC ratepayers of being unable to wheel power through these interconnection points? Please provide quantification where possible.

Response:

FBC's access to market is mainly through its transmission rights on Teck's 71 Line, which provides transmission over the B.C./U.S. interconnection. U.S. transmission is then required from the B.C./U.S interconnection to the Mid-C market. The harm to FBC's ratepayers has been negligible, as its access to 71 Line and U.S. transmission has been reliable. Unavailability is usually related to maintenance on 71 Line during low load times of the year when market access is not usually needed. FBC expects its access on 71 Line will remain reliable over the planning period and that sufficient U.S. transmission will be available to meet market energy needs, although not for capacity requirements to meet expected load. Therefore, FBC expects there will continue to be negligible negative impacts to its ratepayers, but market access will remain a risk until such time as FBC is self-sufficient.

4.5 Please provide FBC's future projections of access to the wholesale electricity market over the period covered by the LTERP (until 2035).

Response:

Please refer to the response to CEC IR1.4.4.

4.6 What, if any, is the economic impact on ratepayers of future limitations on the purchase of market electricity? Please quantify and provide the calculations.

Response:

Please refer to the response to CEC IR 1.4.4.

4.7 What steps, if any, is FBC taking to assure access to the wholesale electricity market?

Response:

FBC expects access to 71 Line and the CEPSA agreement with Powerex will continue. Please also refer to the response to CEC IR 1.4.4.

4.8 What is preventing FBC from purchasing additional transmission capacity to assure access to the wholesale market? Please explain.

Response:

Transmission from the U.S. to B.C. is constrained and there currently is no available transmission that can be reserved on a long-term firm basis. Furthermore, FBC currently has access to sufficient transmission on Teck's 71 Line. It currently would not make economic sense to secure additional transmission above FBC's current requirements, even if it were available. For example, if transmission were available on the BC Hydro system, a 25 MW reservation

would cost $145,000 per month, before taking into account any of the variable ancillary services charges.[4]

4.9 What ability does FBC have to secure priority access to Canadian Entitlement electricity, currently marketed by Powerex? Please explain.

Response:

BC Hydro currently receives the Canadian Entitlement electricity under the Columbia River Treaty and FBC is not able to access this electricity directly.

[4] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/open-access-transmission-tariff/schedule-01-oatt.pdf

5. Reference: Exhibit B-1, page 53

> ### 3.2.1 Gross Load Forecast
>
> FBC's reference case load forecast anticipates a modest rate of load growth over the twenty-year planning horizon of the LTERP. The Company is forecasting an increase in gross load from 3,544 GWh in 2016 to 4,334 GWh by 2035, a compound annual growth rate of 1.1 percent.

5.1 Please provide FBC's Actual gross load, and the Actual growth rates for the last 30 years by customer class. Please break out data from the City of Kelowna to the extent that FBC has the data since purchase and as wholesale customer before purchase. Please provide the information both Before and After DSM.

Response:

FBC's actual historic load and growth rates by customer class are provided in Table 1 below. The City of Kelowna data has been broken out from the Wholesale class for the years 2001 to 2013. FBC is able to provide data for the former City of Kelowna electric utility for the period 2001 to 2013; after 2013 the former City of Kelowna customers are direct customers of FBC. The information provided in Table 2 below is after DSM since savings are embedded in the actual data.

1 **Table 1: FBC Actual Data**

FBC Actual Sales (GWh)										
Year	Residential	Commercial	Wholesale	Kelowna	Industrial	Lighting	Irrigation	Net Load	Losses	Gross Load
1986	721	294	663		280	14	42	2,014	263	2,277
1987	682	298	649		360	13	52	2,054	277	2,331
1988	740	319	695		417	13	45	2,229	281	2,510
1989	768	337	714		455	13	40	2,327	294	2,621
1990	813	352	740		459	14	34	2,412	324	2,736
1991	846	363	756		433	13	41	2,452	312	2,764
1992	850	378	768		426	13	45	2,480	308	2,788
1993	931	409	804		491	12	33	2,679	340	3,019
1994	889	400	814		368	12	44	2,526	413	2,939
1995	933	425	829		327	12	46	2,573	365	2,938
1996	1,004	465	876		313	12	42	2,711	351	3,062
1997	940	459	844		289	12	36	2,580	335	2,915
1998	938	483	837		263	12	48	2,581	304	2,885
1999	945	485	847		273	12	45	2,607	316	2,923
2000	978	498	873		279	12	43	2,683	310	2,993
2001	993	520	602	278	335	10	43	2,782	245	3,026
2002	1,008	524	587	291	363	10	54	2,838	336	3,174
2003	1,013	520	614	293	337	10	52	2,839	347	3,186
2004	1,016	539	619	300	348	10	42	2,875	355	3,230
2005	1,070	568	615	301	357	12	44	2,967	378	3,345
2006	1,049	616	657	314	348	13	43	3,041	364	3,405
2007	1,162	650	585	291	314	13	48	3,064	346	3,410
2008	1,224	661	610	314	218	13	46	3,087	313	3,400
2009	1,273	675	600	331	216	13	49	3,157	321	3,478
2010	1,216	660	571	309	234	14	40	3,044	280	3,324
2011	1,254	657	580	329	271	13	40	3,144	308	3,452
2012	1,224	681	566	331	291	13	38	3,143	271	3,414
2013	1,346	788	351	321	352	13	40	3,211	277	3,489
2014	1,304	866	572		381	16	40	3,178	271	3,450
2015	1,260	853	562		380	16	46	3,116	268	3,384

2

Table 2: FBC Actual Growth Rates (%)

FBC Actual Growth Rates (%)										
Year	Residential	Commercial	Wholesale	Kelowna	Industrial	Lighting	Irrigation	Net Load	Losses	Gross Load
1987	-5.4%	1.4%	-2.1%		28.6%	-7.1%	23.8%	2.0%	5.3%	2.4%
1988	8.5%	7.0%	7.1%		15.8%	0.0%	-13.5%	8.5%	1.4%	7.7%
1989	3.8%	5.6%	2.7%		9.1%	0.0%	-11.1%	4.4%	4.6%	4.4%
1990	5.9%	4.4%	3.7%		0.8%	7.7%	-15.0%	3.7%	10.2%	4.4%
1991	4.1%	3.1%	2.1%		-5.7%	-7.1%	20.6%	1.6%	-3.7%	1.0%
1992	0.5%	4.2%	1.5%		-1.6%	0.0%	9.8%	1.1%	-1.3%	0.9%
1993	9.5%	8.1%	4.7%		15.2%	-7.7%	-26.7%	8.1%	10.4%	8.3%
1994	-4.5%	-2.3%	1.2%		-25.1%	0.0%	33.3%	-5.7%	21.5%	-2.7%
1995	4.9%	6.5%	1.9%		-11.1%	0.0%	4.5%	1.9%	-11.6%	0.0%
1996	7.6%	9.2%	5.6%		-4.4%	0.0%	-8.7%	5.4%	-3.8%	4.2%
1997	-6.4%	-1.1%	-3.7%		-7.5%	0.9%	-14.3%	-4.8%	-4.6%	-4.8%
1998	-0.2%	5.1%	-0.7%		-9.2%	0.0%	33.3%	0.0%	-9.3%	-1.0%
1999	0.7%	0.4%	1.2%		4.0%	-0.9%	-6.3%	1.0%	3.9%	1.3%
2000	3.5%	2.7%	3.0%		2.0%	0.0%	-4.4%	2.9%	-1.9%	2.4%
2001	1.5%	4.4%	-31.1%		20.2%	-16.1%	0.0%	3.7%	-21.1%	1.1%
2002	1.5%	0.8%	-2.5%	4.7%	8.2%	1.7%	26.1%	2.0%	37.4%	4.9%
2003	0.5%	-0.8%	4.7%	0.5%	-7.3%	-0.4%	-4.5%	0.0%	3.3%	0.4%
2004	0.3%	3.7%	0.8%	2.4%	3.3%	0.3%	-18.0%	1.3%	2.3%	1.4%
2005	5.3%	5.3%	-0.7%	0.5%	2.7%	17.4%	3.6%	3.2%	6.5%	3.6%
2006	-2.0%	8.5%	6.9%	4.3%	-2.4%	4.9%	-2.4%	2.5%	-3.8%	1.8%
2007	10.8%	5.4%	-11.0%	-7.3%	-9.8%	1.9%	12.7%	0.8%	-5.0%	0.1%
2008	5.4%	1.7%	4.2%	7.8%	-30.6%	4.5%	-4.4%	0.8%	-9.4%	-0.3%
2009	3.9%	2.2%	-1.6%	5.2%	-1.0%	-0.8%	5.9%	2.3%	2.5%	2.3%
2010	-4.5%	-2.3%	-4.8%	-6.5%	8.3%	8.9%	-17.5%	-3.6%	-12.8%	-4.4%
2011	3.1%	-0.4%	1.5%	6.5%	15.9%	-8.6%	-0.1%	3.3%	10.0%	3.8%
2012	-2.4%	3.6%	-2.5%	0.4%	7.4%	1.9%	-5.8%	0.0%	-12.1%	-1.1%
2013	10.0%	15.8%	-38.1%	-2.9%	21.2%	-0.1%	4.4%	2.2%	2.5%	2.2%
2014	-3.1%	9.8%	63.2%		8.1%	16.0%	0.8%	-1.0%	-2.2%	-1.1%
2015	-3.4%	-1.5%	-1.8%		-0.3%	1.6%	14.9%	-2.0%	-1.3%	-1.9%

5.2 Please provide FBC's forecasts of load and growth rates for the last 30 years by customer class, by vintage year. Please break out data from the City of Kelowna, and provide the information both Before and After DSM.

Response:

FBC is able to locate multi-year load forecasts beginning with the 1995 Integrated Resource Plan.

The DSM forecast was separately identified beginning with the 2009 Resource Plan and the City of Kelowna (CoK) forecast is available beginning with the 2012 Long Term Resource Plan.

The following color key identifies each of the long term resource plan forecasts:

Key
Not available
1995 Integrated Resource Plan
2005 Resource Plan
2009 Resource Plan
2012 Long Term Resource Plan

Table 1: Forecasts Before-DSM (GWh)

Year	Res	Comm	Ind	Whsle	Lighting	Irrigation	Net	Losses	Gross	
1995	931	412	382	835		52	2,611	326	2,938	
1996	946	425	396	857		52	2,675	334	3,009	
1997	961	439	410	879	Included	52	2,741	343	3,083	
1998	976	453	426	902	with	52	2,808	351	3,159	
1999	992	467	441	925	irrigation	52	2,877	360	3,237	
2000	1,008	482	458	950		52	2,949	369	3,317	
2001	1,024	497	475	974		52	3,022	378	3,400	
2002	1,040	513	492	1,000		52	3,097	387	3,484	
2003	1,057	530	510	1,026		52	3,174	397	3,571	
2004	1,074	547	529	1,052		52	3,254	407	3,660	
2005	1,055	549	323	960	10	47	2,945	366	3,311	
2006	1,070	562	360	978	10	47	3,028	336	3,364	
2007	1,082	573	363	992	10	47	3,068	340	3,409	
2008	1,093	582	367	1,005	10	47	3,104	344	3,449	
2009	1,228	685	227	929	14	48	3,130	298	3,426	
2010	1,250	701	230	936	14	48	3,179	303	3,480	
2011	1,273	722	234	943	14	48	3,232	308	3,538	CoK
2012	1,282	708	253	601	15	45	3,241	314	3,555	337
2013	1,306	728	261	615	15	45	3,312	321	3,632	341
2014	1,332	746	266	627	16	45	3,377	327	3,703	345
2015	1,359	763	269	637	16	45	3,436	333	3,769	348
2016	1,385	776	259	646	17	45	3,479	337	3,816	352
2017	1,411	790	251	653	17	45	3,522	341	3,863	356

Table 2: Forecast Growth Rates Before-DSM

Year	Res	Comm	Ind	Whsle	Lighting	Irrigation	Net	Losses	Gross	
1995	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1996	1.6%	3.2%	3.7%	2.6%	Included with irrigation	0.0%	2.4%	2.4%	2.4%	
1997	1.6%	3.2%	3.7%	2.6%		0.0%	2.5%	2.5%	2.5%	
1998	1.6%	3.2%	3.7%	2.6%		0.0%	2.5%	2.5%	2.5%	
1999	1.6%	3.2%	3.7%	2.6%		0.0%	2.5%	2.5%	2.5%	
2000	1.6%	3.2%	3.7%	2.6%		0.0%	2.5%	2.5%	2.5%	
2001	1.6%	3.2%	3.7%	2.6%		0.0%	2.5%	2.5%	2.5%	
2002	1.6%	3.2%	3.7%	2.6%		0.0%	2.5%	2.5%	2.5%	
2003	1.6%	3.2%	3.7%	2.6%		0.0%	2.5%	2.5%	2.5%	
2004	1.6%	3.2%	3.7%	2.6%		0.0%	2.5%	2.5%	2.5%	
2005	-1.8%	0.4%	-38.9%	-8.7%	NA	NA	-9.5%	-10.1%	-9.5%	
2006	1.4%	2.4%	11.5%	1.9%	0.0%	0.0%	2.8%	-8.2%	1.6%	
2007	1.1%	2.0%	0.8%	1.4%	0.0%	0.0%	1.3%	1.2%	1.3%	
2008	1.0%	1.6%	1.1%	1.3%	0.0%	0.0%	1.2%	1.2%	1.2%	
2009	12.4%	17.7%	-38.1%	-7.6%	40.0%	2.1%	0.8%	-13.4%	-0.7%	
2010	1.8%	2.3%	1.3%	0.8%	0.0%	0.0%	1.6%	1.7%	1.6%	
2011	1.8%	3.0%	1.7%	0.7%	0.0%	0.0%	1.7%	1.7%	1.7%	
2012	0.7%	-1.9%	8.1%	-36.3%	7.1%	-6.3%	0.3%	1.9%	0.5%	**CoK**
2013	1.9%	2.8%	3.2%	2.3%	0.0%	0.0%	2.2%	2.2%	2.2%	1.1%
2014	2.0%	2.5%	1.9%	2.0%	6.7%	0.0%	2.0%	1.9%	2.0%	1.1%
2015	2.0%	2.3%	1.1%	1.6%	0.0%	0.0%	1.7%	1.8%	1.8%	1.1%
2016	1.9%	1.7%	-3.7%	1.4%	6.3%	0.0%	1.3%	1.2%	1.2%	1.1%
2017	1.9%	1.8%	-3.1%	1.1%	0.0%	0.0%	1.2%	1.2%	1.2%	1.1%

Table 3: Forecasts After-DSM (GWh)

Year	Res	Comm	Ind	Whsle	Lighting	Irrigation	Net	Losses	Gross	
1995	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1996	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1999	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2009	1,222	678	224	921	14	48	3,107	296	3,401	
2010	1,243	695	228	927	14	48	3,154	301	3,453	
2011	1,266	715	231	934	14	48	3,207	306	3,511	CoK
2012	1,264	696	250	593	14	44	3,193	309	3,502	333
2013	1,276	709	255	602	14	43	3,233	310	3,543	334
2014	1,290	719	258	608	13	43	3,266	311	3,577	334
2015	1,301	727	258	613	13	42	3,289	310	3,599	335
2016	1,312	732	245	615	13	41	3,293	308	3,601	335
2017	1,328	737	235	618	13	41	3,307	307	3,614	336

Note: Because DSM is calculated for Wholesale loads and not on an individual Wholesale customer basis, the after-DSM CoK load has been based on an estimated allocation of the CoK percentage of Wholesale load for the 2012 LTRP after-DSM forecast.

Table 4: Forecast Growth Rates After-DSM

Year	Res	Comm	Ind	Whsle	Lighting	Irrigation	Net	Losses	Gross	
1995	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1996	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1999	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2010	1.7%	2.5%	1.8%	0.7%	0.0%	0.0%	1.5%	1.7%	1.5%	
2011	1.9%	2.9%	1.3%	0.8%	0.0%	0.0%	1.7%	1.7%	1.7%	
2012	-0.2%	-2.7%	8.2%	-36.5%	0.0%	-8.3%	-0.4%	1.0%	-0.3%	CoK
2013	0.9%	1.9%	2.0%	1.5%	0.0%	-2.3%	1.3%	0.3%	1.2%	1.1%
2014	1.1%	1.4%	1.2%	1.0%	-7.1%	0.0%	1.0%	0.3%	1.0%	1.1%
2015	0.9%	1.1%	0.0%	0.8%	0.0%	-2.3%	0.7%	-0.3%	0.6%	1.1%
2016	0.8%	0.7%	-5.0%	0.3%	0.0%	-2.4%	0.1%	-0.6%	0.1%	1.1%
2017	1.2%	0.7%	-4.1%	0.5%	0.0%	0.0%	0.4%	-0.3%	0.4%	1.1%

5.3 Please provide FBC's revenue by customer class over the last 30 years.

Response:

Please refer to the table below.

Table 1: Historical Revenue by Customer Class ($000s)

	Residential	Commercial	Industrial	Wholesale	Other (Lighting & Irrigation)
1987	22,250	13,370	8,635	14,511	2,154
1988	23,679	14,121	9,821	15,413	2,058
1989	26,136	15,873	11,386	17,366	2,133
1990	29,458	17,457	12,192	18,422	2,143
1991	31,702	18,303	12,128	20,067	2,208

	Residential	Commercial	Industrial	Wholesale	Other (Lighting & Irrigation)
1992	36,400	20,899	13,147	22,689	2,507
1993	41,511	24,023	16,495	25,479	2,419
1994	41,308	23,643	13,040	26,487	2,720
1995	48,080	23,490	12,783	28,146	2,770
1996	52,170	26,786	12,792	30,997	2,852
1997	50,742	25,869	11,866	29,729	2,715
1998	50,692	26,510	11,912	29,663	3,104
1999	52,706	26,356	11,700	29,742	2,909
2000	57,313	29,473	12,695	30,490	3,333
2001	59,892	30,965	14,778	32,581	3,603
2002	61,837	32,171	16,138	34,821	3,471
2003	70,345	36,346	15,768	36,763	3,733
2004	71,855	37,532	16,766	39,673	3,297
2005	79,177	40,918	17,945	41,424	3,656
2006	87,446	46,844	18,871	46,299	3,902
2007	93,100	50,100	19,170	43,381	3,900
2008	102,600	53,820	14,470	45,614	4,405
2009	112,059	57,798	14,051	49,946	4,717
2010	114,375	59,957	16,093	51,765	4,602
2011	129,436	62,290	21,842	59,373	5,149
2012	134,421	59,514	21,798	61,990	5,219
2013*	158,895	67,661	27,022	49,211	5,743
2014	161,453	76,267	30,059	43,375	6,176
2015	163,258	79,354	29,837	43,959	6,968
2016	167,967	84,912	31,077	44,541	6,688

* Decreases in the Wholesale and increases in all customer classes are due to FBC's purchase of the utility assets of CoK. CoK is no longer a Wholesale customer of FBC and the formerly indirect customers of CoK became direct customers of FBC.

6. Reference: Exhibit B-1, page 55 and page 55

> The peak demand forecast is the largest amount of capacity expected at one point in time on the FBC system due to high customer demand, which is affected by weather and system growth. FBC's system is dual peaking, with annual winter and summer peaks. Winter peaks have historically been larger than the summer peak and are forecast to continue to be larger in the future.
>
> The winter peak is when the most capacity is needed at a single point in time during the months of November to February and is usually on one of the coldest days of the year. The reference case winter peak demand forecast increases from 731 MW in 2016 to 885 MW in 2035, growing at a compound annual growth rate of 1.0 percent.
>
> The reference case summer peak demand forecast increases from 590 MW in 2016 to 716 MW in 2035, growing at a compound annual growth rate of 1.0 percent.

6.1 On what basis did FBC select an annual compound growth rate of 1.0% for the peak demand forecast?

Response:

The one percent compound annual growth rate is the average of the forecast annual growth rates from 2016 to 2035 that were used to create the peak demand forecast.

6.2 Please provide actual summer and winter peak demand, including growth rates for the last 30 years. Please break out data from Kelowna if available and qualify the data as either Before or After DSM.

Response:

FBC is able to provide the actual summer and winter peaks below from 1989 to 2016 (28 years), and CoK from 2005 to 2016.

Table 1: Historical Actual Winter and Summer Peaks (MW)

	FBC Service Territory				City of Kelowna			
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
Year	MW		% Change		MW		% Change	
1989	572	381	-	-				
1990	623	396	8.9%	3.9%				
1991	579	400	-7.1%	1.0%				
1992	620	420	7.1%	5.0%				
1993	640	415	3.2%	-1.2%				
1994	642	469	0.3%	13.0%				
1995	643	449	0.2%	-4.3%				
1996	667	447	3.7%	-0.4%				
1997	640	448	-4.0%	0.2%				
1998	630	489	-1.6%	9.2%				
1999	548	461	-13.0%	-5.7%				
2000	614	464	12.0%	0.7%				
2001	560	497	-8.8%	7.1%				
2002	572	515	2.1%	3.6%				
2003	609	526	6.5%	2.1%				
2004	718	511	17.9%	-2.9%				
2005	708	512	-1.4%	0.2%	61	55	-	-
2006	718	554	1.4%	8.2%	72	64	18.0%	16.4%
2007	683	569	-4.9%	2.7%	68	66	-5.6%	3.1%
2008	746	537	9.2%	-5.6%	70	59	2.9%	-10.6%
2009	714	561	-4.3%	4.5%	73	64	4.3%	8.5%
2010	707	554	-1.0%	-1.2%	70	64	-4.1%	0.0%
2011	669	519	-5.4%	-6.3%	75	62	7.1%	-3.1%
2012	737	551	10.2%	6.2%	66	67	-12.0%	8.1%
2013	699	579	-5.2%	5.1%	73	69	10.6%	3.0%
2014	684	601	-2.1%	3.8%	66	68	-9.6%	-1.4%
2015	624	597	-8.8%	-0.7%	69	72	4.5%	5.9%
2016	712	594	14.1%	-0.5%	76	70	10.1%	-2.8%

6.3 Please break out data from Kelowna.

Response:

Please refer to the response to CEC IR 1.6.2.

6.4 Please provide FBC's capacity forecasts by vintage year, breaking out City of Kelowna since purchase, and as wholesale prior to purchase to the extent available.

Response:

FBC is able to provide the forecast winter and summer capacity forecasts from 2005 to 2016. FBC did not forecast capacity for the area formerly served by the CoK's distribution utility.

	Before DSM		After DSM	
Year	Winter	Summer	Winter	Summer
2005	712	678	N/A	N/A
2006	723	688	N/A	N/A
2007	732	697	N/A	N/A
2008	740	705	N/A	N/A
2009	701	560	697	557
2010	712	568	707	565
2011	724	578	719	575
2012	730	730	721	721
2013	745	745	731	731
2014	758	758	741	741
2015	770	770	747	747
2016	780	780	751	751
2017	789	789	758	758

Key
2005 Resource Plan
2009 Resource Plan
2012 Long Term Resource Plan

7. Reference: Exhibit B-1, page 57

> ***3.3.1.1 Commercial Load***
>
> There is a high statistical correlation between the provincial GDP and FBC's commercial load, which is explained in further detail in Appendix E. The commercial class is a mix of different types of businesses, from small store-front operations and restaurants to larger operations such as hotels and ski resorts. In 2015, there were 14,976 customers in the commercial class, representing 25 percent of the gross load.
>
> Commercial load growth is expected to increase at a compound annual growth rate of 1.6 percent over the planning horizon. The commercial load is forecast to increase significantly during the near to medium term and then slow somewhat due to reduced economic growth.

7.1 Please provide a comparison of provincial GDP forecasts and the actual GDP growth rates over the last 30 years.

Response:

The 2012 LTRP was FBC's first long term forecast to use GDP as a driver. As a result FBC is only able to include the CBOC Provincial GDP forecasts from 2011 to 2015.

1 **Table 1: Actual and Forecast Provincial GDP Growth Rates from the CBOC**

Year	GDP Growth (%)	2012 LTRP GDP Forecast (%)
1986	1.4%	
1987	5.4%	
1988	4.7%	
1989	4.0%	
1990	2.1%	
1991	1.4%	
1992	3.2%	
1993	4.7%	
1994	4.8%	
1995	2.7%	
1996	2.2%	
1997	3.3%	
1998	1.2%	
1999	3.0%	
2000	4.5%	
2001	1.1%	
2002	3.2%	
2003	2.6%	
2004	3.8%	
2005	4.7%	
2006	4.1%	
2007	2.7%	
2008	-2.3%	
2009	-2.3%	
2010	3.7%	
2011	1.9%	2.0%
2012	2.5%	3.0%
2013	2.1%	3.2%
2014	2.5%	2.7%
2015	2.2%	2.4%

2

3

8. Reference: Exhibit B-1, page 57

> ***3.3.1.2 Industrial Load***
>
> In 2015, there were 50 customers in the industrial class, representing 11 percent of FBC's gross load.
>
> Industrial load growth is expected to increase at a compound annual growth rate of 1.5 percent over the planning horizon. The industrial load is forecast to have consistent strong growth during the planning horizon except for during the short term which is partly due to the forecast decline of the forestry sector from the mountain pine beetle epidemic.

8.1 Please provide FBC's basis for selecting 1.5% as a compound annual growth rate.

Response:

The industrial demand is calculated using:

1. The industrial survey results provided by each individual customer for the first five years of the forecast (or their individual sector GDP forecast from the CBOC if their surveys were not returned)

2. The composite sector GDP growth rate for the remaining 15 years of the forecast period.

The 1.5% growth rate was then calculated by averaging the growth rates for the industrial load as shown in the table below:

Table 1: Industrial Growth Rates

Year	Growth Rate (%)
2017	4.1%
2018	0.4%
2019	0.9%
2020	0.8%
2021	1.5%
2022	1.4%
2023	1.6%
2024	1.5%
2025	1.5%
2026	1.6%
2027	1.5%
2028	1.5%
2029	1.5%
2030	1.2%
2031	1.4%
2032	1.6%
2033	1.6%
2034	1.5%
2035	1.5%
Average=	**1.5%**

8.2 Please provide evidence that BC Hydro is experiencing similar load growth rates for industrial accounts.

Response:

According to BC Hydro's 2013 Integrated Resource Plan, Appendix 2A, Page 15, BC Hydro was expecting compound annual growth from 2012 to 2033 of 1.3% for the industrial class, which is similar to the 1.5% forecast for FBC.

9. Reference: Exhibit B-1, page 58

> **3.3.2 Population Growth**
>
> BC Stats forecasts annual population growth of 1.0 percent on average over the planning horizon for FBC's service territory. This is consistent with the 1.0 percent annual average growth rate experienced in the last 10 years. Population growth is forecast to be strongest at the start of the planning horizon at 1.2 percent and then is predicted to fall gradually to 0.7 percent by 2035.

9.1 Please provide the population growth forecast by year, breaking out the City of Kelowna.

Response:

The annual population growth for FBC's service territory is provided in the table below. BC Stats does not forecast population for the area formerly serviced by the CoK distribution utility.

Table 1: BC Stats Annual Population Growth Forecast for the FBC Service Area

Year	Annual Growth
2016	2,819
2017	2,899
2018	2,878
2019	2,884
2020	2,910
2021	2,920
2022	2,938
2023	2,883
2024	2,817
2025	2,804
2026	2,754
2027	2,691
2028	2,633
2029	2,561
2030	2,480
2031	2,422
2032	2,360
2033	2,289
2034	2,221
2035	2,131

9.2 Please provide the population growth over the last 30 years, and break out the City of Kelowna.

Response:

The population growth projections provided by BC Stats data received by FBC commence in 1987. BC Stats does not provide population for the area formerly serviced by the CoK distribution utility.

Table 1: BC Stats Annual Population Growth for the FBC Service Area

Year	Annual Growth	Growth Rate
1987	1,331	0.8%
1988	3,137	2.0%
1989	5,389	3.3%
1990	6,415	3.8%
1991	6,972	4.0%
1992	7,674	4.2%
1993	6,896	3.6%
1994	5,607	2.8%
1995	4,577	2.3%
1996	3,445	1.7%
1997	2,170	1.0%
1998	1,044	0.5%
1999	304	0.1%
2000	348	0.2%
2001	613	0.3%
2002	1,042	0.5%
2003	649	0.3%
2004	1,682	0.8%
2005	3,215	1.5%
2006	3,952	1.8%
2007	5,226	2.3%
2008	4,464	1.9%
2009	1,319	0.6%
2010	301	0.1%
2011	1,084	0.5%
2012	355	0.1%
2013	1,335	0.6%
2014	2,710	1.1%
2015	2,679	1.1%

9.3 Please provide BC Stats forecasts for population growth and compare to actual population growth for the last 30 year period.

Response:

FBC began to use the BC Stats population data as a driver for the residential customer count forecast in the 2005 Resource Plan (RP). The 2005 RP BC Stats data is unavailable because the 2005 forecast was contracted out and the information was not included with the forecast. The BC Stats Population forecast data is only available from the 2009 RP since the 2012 LTRP used the CBOC provincial housing starts instead of population to forecast the residential customer count. Growth rates are available beginning in 1987.

Table 1: Actual and Forecast Population Growth for the FBC Service Area from BC Stats (%)

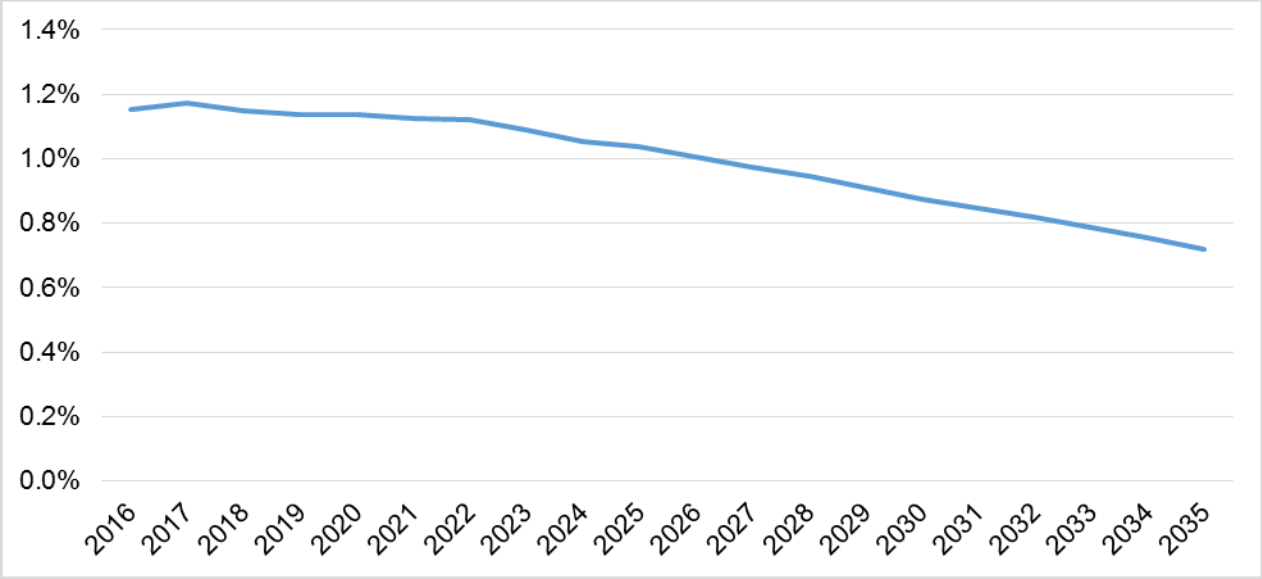
Year	Population Growth (%)	2009 RP Population Growth Forecast (%)
1987	0.8%	
1988	2.0%	
1989	3.3%	
1990	3.8%	
1991	4.0%	
1992	4.2%	
1993	3.6%	
1994	2.8%	
1995	2.3%	
1996	1.7%	
1997	1.0%	
1998	0.5%	
1999	0.1%	
2000	0.2%	
2001	0.3%	
2002	0.5%	
2003	0.3%	
2004	0.8%	
2005	1.5%	
2006	1.8%	
2007	2.3%	
2008	1.9%	1.0%
2009	0.6%	1.0%
2010	0.1%	1.0%
2011	0.5%	1.0%
2012	0.1%	1.0%
2013	0.6%	1.0%
2014	1.1%	1.0%
2015	1.1%	0.9%

9.4 Please explain why FBC is using consistent, average population growth over the planning period when the trend is not consistent and declining.

Response:

FBC is not using consistent average population growth over the planning period. The population growth forecast starts as 1.2 percent at the beginning of the planning horizon and then declines to 0.7 percent by 2035. The graph below shows the annual population growth rate forecast used for FBC's service area from BC Stats' forecast.

Figure 1: FBC Annual Population Growth Forecast (%)



9.5 Please provide the forecast load using current BC Stats forecasts for population growth of the average.

Response:

Table 1: Residential Load Forecast Using BC Stats Average Population Forecast (GWh)

Year	After Savings (GWh)
2016	1,352
2017	1,366
2018	1,382
2019	1,399
2020	1,416
2021	1,432
2022	1,447
2023	1,462
2024	1,477
2025	1,493
2026	1,509
2027	1,525
2028	1,541
2029	1,558
2030	1,574
2031	1,591
2032	1,607
2033	1,624
2034	1,642
2035	1,659

10. Reference: Exhibit B-1, page 70

> **4.3 *RPAG FEEDBACK***
>
> The load scenarios described above were discussed with the RPAG stakeholders in the April 27, 2016 workshop. At that session, FBC received feedback regarding the load drivers and scenarios. For example, one stakeholder commented that the electric vehicle penetration included in the high consumption boundary scenario (Scenario 1) might be overstated if electric vehicle manufacturers are not able to keep up with the demand from customers. Another stakeholder commented that the generally older population in the FBC service area relative to other cities, such as Vancouver, might lead to lower adoption of EVs in the FBC territory. Another stakeholder commented that the level of solar PV with storage seemed high without time-of-use rates providing an incentive for the use of energy storage. FBC notes that while the high and low boundary scenarios represent plausible extremes, the three intermediate scenarios cover less-extreme scenarios and may be more aligned with those situations described by stakeholders in the workshop.

10.1 Please provide any evidence FBC may have on the automobile industry's capacity to produce EVs, with quantification, and explain how that may affect the timing of system planning and infrastructure.

Response:

Although FBC does not currently have any evidence regarding the automobile industry's capacity to produce EVs, industry observers believe current EV battery production levels to be insufficient to support mass production of battery-only EVs.

10.2 Please provide a comparison of FBC's expected EV adoption rates to that anticipated in larger urban environments elsewhere in Canada and the US.

Response:

FBC is unable to provide the requested comparison as FBC does not currently have information regarding EV adoption rates specific to urban areas.

10.3 Does FBC expect to introduce Time of Use rates at any time in the future? Please explain why or why not.

Response:

The Company offers Time of Use (TOU) rates for all individually metered customer categories with the exception of Residential. Residential TOU rates were closed by Commission order in conjunction with the introduction of the residential conservation rate as the default rate for those customers. FBC does intend to examine TOU rates generally in its upcoming Rate Design Application in order to determine whether such rate structures would be appropriate based on principles of cost causation.

10.3.1 If yes, please provide an estimate of when FBC might introduce TOU rates in the future.

Response:

Please refer to the response to CEC IR 1.10.3.

10.3.2 If yes, please provide an overview of any work FBC has done on TOU rates.

Response:

Please refer to the response to CEC IR 1.10.3.

10.3.3 If yes, please provide FBC's expectations as to how TOU rates would affect peak load. Please provide quantification.

Response:

Please refer to the response to CEC IR 1.10.3.

10.4 Does FBC expect that TOU rates will result in additional conservation and efficiency savings? Please explain why or why not.

Response:

FBC has not undertaken conservation and efficiency savings analysis for TOU rates at this time. Please refer to the response to CEC IR 1.10.3.

10.4.1 If yes, please provide quantification of any savings FBC believes may be possible if available.

Response:

Please refer to the response to CEC IR 1.10.4.

10.5 Please provide BC Hydro's TOU pilot rate experience data showing conservation and efficiency savings.

Response:

On March 3, 2017, BC Hydro reviewed its experience with its 2006 TOU pilot at a workshop related to its 2015 Rate Design Application.

The materials for that workshop can be found at the following link:

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/20170303-RDA-Module2-Workshop.pdf

The TOU Pilot Summary begins at slide 21.

11. Reference: Exhibit B-1, page 87

> An assessment of reactive power[90] capabilities is also necessary. As previously noted, the FBC system consists of two areas, the Kootenay region, with surplus generation, and the Okanagan, with a total absence of generation. The lack of dynamic reactive support in the Okanagan (due to absence of generation resources which can respond to load changes in real-time) can lead to low voltages or voltage collapse during contingency conditions.
>
> Each thermal or voltage violation found in the studies is then analyzed in order to define the most cost-effective mitigation plan. These studies identify a collection of transmission reinforcement projects that are required within the 20 year planning horizon.

11.1 Please provide data from the last 10 years to illustrate how the lack of dynamic reactive support in the Okanagan has led to low voltages or voltage collapse.

Response:

Presently the Kelowna peak load is below the threshold where a single contingency will result in voltage violations necessitating the need for additional reactive support. Section 6.2.3 addresses, in general, how transmission studies are undertaken, but it does not speak to the results of these studies. The projects that are required within a 20 year timeframe are listed in Section 6.3. At this time, reactive dynamic support is not, and has not been, an issue in the Okanagan.

11.2 Please provide a brief overview of the cost-effective mitigation plans that have been defined to address the lack of dynamic reactive support in the Okanagan including any known costs.

Response:

The possible mitigation plans would be:

- Installation of a new generation resource;
- Expansion of the transmission system (i.e. adding a new line or new point of interconnection with BC Hydro); and.
- Installation of a Static Var Compensator (SVC). An SVC is a solid state device that provides a similar level of dynamic reactive support as a rotating generator.

Since the requirement is beyond the 20 year planning horizon of the LTERP, no detailed cost study has been done. All things being equal, an SVC is generally much less costly than either new generation or transmission lines.

11.3 Please advise whether upgrades to the connections to BC Hydro's system at Vernon Terminal Station and / or Vaseau Lake Terminal Station (reference section 6.1.2) would address this problem, and what those upgrades would entail.

Response:

No, the strength of the existing BC Hydro points of interconnection is not an issue.

11.4 Would such upgrades be cost effective mitigation to the lack of dynamic support in the Okanagan? Please explain why or why not and provide quantification of any known costs.

Response:

Please refer to the response to CEC IR 1.11.3.

11.5 Are there interconnection guarantees or limitations under the PPA 3808 agreement?

Response:

The BC Hydro PPA is a commercial arrangement detailing the scheduling of energy and capacity from the BC Hydro system to the FBC system and does not provide for any interconnection guarantees or limitations. The interconnection guarantees or limitations between BC Hydro and FBC are covered under the Amended and Restated Interconnection Agreement between BC Hydro and FBC, dated May 16, 2013, and, to a lesser extent, the Amended and Restated Wheeling Agreement between BC Hydro and FBC, dated July 16, 2013.

12. Reference: Exhibit B-1, page 89

> **6.3.1 Impacts of Supply-Side Resource Options**
>
> FBC considers supply-side resource option location assumptions to determine transmission and distribution requirements as part of the LTERP development process. Regardless of the location, supply-side resources included in the LTERP typically require some amount of local transmission and distribution improvements to allow them to interconnect with FBC's electrical system.
>
> The most impactful resource addition currently identified would be the integration of a new large-scale generation resource, such as a gas-fired generation plant, within the Kelowna 138-kV sub-transmission network. This is because this resource could defer the requirement for the proposed third 230/138-kV bulk transformer at the Lee Terminal in Kelowna (as discussed in section 6.3).

12.1 Please provide quantification of the costs associated with the new gas fired generation plant.

Response:

No detailed quantification is available at this time; however, based on the approximate size of the generation resource that would be required, FBC estimates the cost to be in excess of $250 million.

12.2 Please provide details of any planning or feasibility studies FBC has done for the gas fired generation plant identified, and provide the NPV analysis if one has been completed.

Response:

Due the high cost of a gas fired generation plant compared to other options (such as a bulk transformer addition) this option was rejected with respect to addressing the Kelowna-area transmission limitations. As such, no further planning or feasibility studies were conducted.

12.3 What financial effect would the deferral of the proposed third transformer at the Lee Terminal have? Please discuss and provide quantification.

Response:

The financial effect of deferring the project would be the reduction in revenue requirements associated with the financing cost (cost of equity, cost of debt) and depreciation and taxes. For a hypothetical system reinforcement project costing $20 million, this would equate to approximately $1.7 million of revenue reduction per year following the first year of the project being placed into service. Incremental rate impacts are expected only in the first two years, with a cumulative impact of approximately 0.5 percent.

12.4 How would the gas-fired generation plant affect FBC's proportion of clean energy? Please discuss and provide quantification.

Response:

A gas-fired generation plant, if required, would reduce the proportion of clean energy in FBC's portfolio. The specific proportional reduction would depend on how much energy and capacity is required from the plant. If the plant was required for peak demand purposes, as is contemplated with the SCGT plant in FBC's preferred portfolio (discussed in Section 9.3.6 of the LTERP), the impact on FBC's proportion of clean resources would be minimal. For the preferred portfolio, by 2035 the SCGT represents less than 1 percent of the total energy requirement with the balance of the requirement met from clean resources (with the exception of supply from BC Hydro, which is assumed to be 98 percent clean).

13. Reference: Exhibit B-1, page 89

> **6.4.1 Distributed Generation**
>
> Currently, FBC has approximately 110 Net Metering Program customers with Distributed Generation (DG) facilities (mostly rooftop solar PV installations) interconnected on the distribution system.[93] Combined, these facilities represent less than 1 MW of non-firm generating capacity, which is less than 0.5 percent of the approximate 225 MW firm generating capacity of FBC's four hydroelectric generating plants. As a result, the near-term impacts of existing DG facilities on transmission and distribution grid operations and reliability are currently relatively low.
>
> However, the pace of FBC DG interconnections has increased over the past few years. 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 will be required to ensure that potential system impacts and necessary mitigation are understood and addressed in the FBC system.

13.1 When does FBC intend to undertake the studies necessary to understanding system impacts and identifying mitigation options?

Response:

Further studies will be undertaken when adoption rates of new DG suggest that more detailed investigation is required. Given the current low uptake by customers, it is not expected that this will occur for several years.

13.2 Please provide data on the increase in DG interconnections over the past five years.

Response:

The total number of net metering customers by year is as follows:

2012 - 16

2013 – 20

2014 – 43

2015 – 83

2016 - 159

13.3 Please provide FBC's projections on the number of DG connections over the next five years.

Response:

FBC has not forecast DG interconnections over the next five years.

13.4 At what threshold level of generation would FBC expect DG to have a meaningful impact on transmission and grid operations and reliability? Please discuss and provide quantification.

Response:

Threshold levels are dependent on the amount and location of generation added to the system. One generally-applied threshold is that further study is required when the connected distributed generation exceeds approximately 15 percent of the feeder peak load.

Please also refer to the response to CEC IR 1.13.1.

13.5 Could small scale wind power also be integrated into the FBC systems in DG?

Response:

Yes. Small scale wind power is an eligible technology under the FBC Net Metering Program, and more generally, such installations can be interconnected with the FBC system provided that they comply with all relevant standards and FBC interconnection requirements.

13.5.1 If yes, please explain whether or not this is likely to become another DG option for customers and why.

Response:

FBC believes that wind generation is not likely to proliferate relative to solar PV options due to the dominance of solar offerings in the marketplace as well as cost and siting considerations. Of note, by a number of statistical measures (lowest average wind speed, most days of light wind speed, and fewest days of high wind), Kelowna is considered to be the least windy city in Canada. Given that a large proportion of FBC customers live within Kelowna municipal limits (i.e. the Okanagan valley bottom), FBC does not expect a significant penetration of wind DG by customers within this area of the FBC system

13.5.1.1. If it is likely to become another DG option, please advise what steps must be taken by FBC to integrate small scale wind power into the FBC electricity system and quantify any known costs.

Response:

As explained in the response to CEC IR 1.13.5.1, FBC does not expect that the penetration of wind generation will become commonplace in the FBC service area. The Company does not currently have any wind generation connected. However, should such a customer emerge, the basic steps for interconnection are no different than for solar PV, and the Company does not believe that costs, from its perspective, would be any different. The physical cost of interconnection is borne by the customer.

14. Reference: Exhibit B-1, page 90

> Notwithstanding the limited impacts given current adoption rates, the potential future impacts on transmission and distribution system planning and operations are more complex. Intermittent renewable generation creates many new challenges not experienced with conventional distributed generation. Distributed solar PV increases the complexity of managing voltage regulation on circuit feeders due to its intermittent nature. These facilities will have increasing impacts on the distribution system first and then the transmission system later as DG growth continues.
>
> The extent to which DG affects power losses and voltage profiles depends on the type of DG technology, penetration levels, and the location of its connection to the grid. Depending on its location, the integration of DG can reduce power losses on the transmission and distribution network, but as the penetration level increases, the power losses may begin to increase.
>
> If DG uptake increases significantly in the near future, FBC transmission and distribution planners will need to have the tools and knowledge for planning and modeling a high-penetration of solar PV or other DG technology into the system. Alternative engineering designs, technology solutions, and new and updated planning and operations practices may be needed for the FBC transmission and distribution system of the future.

14.1 Does FBC currently have the tools and knowledge for planning and modelling a high penetration of DG technology into the system at present?

Response:

FBC employs professional engineers who have the necessary skills for modelling the present power system and for reasonably foreseen levels of DG in the near-term. Tools available within the Company include load flow, short circuit, transient stability and harmonic analysis software packages.

If the future high penetration of DG results in complexity that could exceed the modeling capabilities of current staff or tools, FBC would supplement these resources with additional training, software tools or specialist consultants, if and when required.

14.1.1 If no, please provide a brief overview of the costs and timing of when these requirements will be acquired.

Response:

Please refer to the response to CEC IR 1.14.1.

14.1.1.1 If FBC does not have plans to acquire the tools and knowledge, please identify the criteria FBC will use to determine when alternative engineering designs, technology solutions and new and updated planning and operations practices will be required.

Response:

Please refer to the response to CEC IR 1.14.1.

15. Reference: Exhibit B-1, page 91

> The Electric Power Research Institute (EPRI) has analyzed distribution system impacts of Plug-in Electric Vehicle (PEV) charging and, in its report[94], concluded that:
>
> - Diversity of vehicle location, charging time, and energy demand will minimize the impact on utility distribution systems;
> - Level 1 (standard residential voltage; no extra cost) charging generates the fewest distribution system impacts;
> - Higher power (Level 2) charging generates stronger system impacts and is typically not required for most customer charging scenarios with light duty vehicles;
> - Short-term PEV impacts for most utility distribution systems are likely minimal and localized to areas where the available capacity per customer is already low; and
> - Controlled or managed charging could defer system impacts for a significant period of time.
>
> FBC intends to use the recommendations from the EPRI study as a guide. The potential stresses on the electric grid can be mitigated through asset management, system design practices, and, to some degree, managing the timing of charging PEVs to shift the load away from system peak. A proactive FBC approach that includes understanding where PEVs are appearing in the system, addressing near-term localized impacts, and developing both customer programs and technologies for managing long-term charging loads will effectively and efficiently support PEV adoption.

15.1 In what ways can FBC use 'asset management' to mitigate potential stresses on the electrical grid? Please explain.

Response:

Asset management in this context is a general reference to maximizing the potential capabilities of grid assets. For example, by proactively identifying potential overloads on distribution transformers that could result from high levels of connected EVs or DG, FBC could potentially re-balance customer loads to adjacent transformers with sufficient capacity thereby avoiding potential equipment failures. One method to accomplish this would be by using the recently installed FBC AMI metering system to calculate the loading on individual transformers to identify any that may be approaching or exceeding equipment ratings. The same technique could be applied on a larger scale to calculate the load at any given point on the distribution system to identify potentially overloaded devices or conductors.

Asset management also involves the identification of non-technical losses related to theft as these unknown loads can result in premature equipment failure, particularly since electricity theft is typically conducted without the benefit of the certification required under the *Safety Standards Act.*

15.2 What types of 'systems design practices' can FBC use to mitigate potential stresses on the electrical grid? Please explain.

Response:

In general terms, 'system design practices' refers to the ability of FBC to develop internal standards for equipment sizing and installation practices to accommodate varying uptake levels of DG or EV technology. The standards would build off the asset utilization information described in the response to CEC IR 1.15.1.

15.3 What are the expected costs of any system design and upgrades that may be needed to accommodate the adoption of EVs?

Response:

Given the current low uptake rates of EVs by customers, FBC is unable to speculate on the expected costs or timeframes for any system design or upgrades at this time.

15.4 How much lead time is required for FBC to do any required system design and upgrades to accommodate the adoption of EVs? Please explain.

Response:

Please refer to the response to CEC IR 1.15.3.

15.5 Is FBC aware of the work BC Hydro has done to plan for load growth from EVs?

Response:

Although FBC is aware of the work that has been performed by BC Hydro and Powertech Labs on EV charging stations and smart grid demonstration projects, the majority of FBC's work with BC Hydro regarding EVs has been focused around identifying opportunities to expand the provincial DC fast-charging network.

15.5.1 If yes, please explain how this work has informed the FBC LTERP submission.

Response:

The EV scenarios modeled by FBC in Section 4 of the LTERP, although not directly informed by the work BC Hydro has performed regarding EVs, do reflect general assumptions derived from provincial data. For example, the residential home charging profiles are estimated based on vehicle data-diary reported home arrival times for 528 vehicles in B.C. As well, the estimated turn-over rate for vehicle stock is derived from provincial vehicle registration data as well as new motor vehicle sales data.

15.5.2 Would FBC consider mandatory TOU for EV charging? Please explain why or why not.

Response:

The Company will examine TOU rates generally as part of its 2017 Rate Design Application. At the current time, FBC does not believe that it would be necessary to impose a mandatory TOU rate for EV charging. In the FBC context, the primary concern surrounding the proliferation of EVs is the potential impact on local infrastructure due to the increase in load that is likely to occur near daily system peaks.

A properly designed optional rate, reflective of costs that such a load may impose, could provide the economic signal necessary to influence customer behaviour.

FBC is also considering non-rate-based solutions, such as providing incentives for customers to purchase EV chargers that delay charging to off-peak periods.

16. Reference: Exhibit B-1, page 93 and page 49

> With regard to the BC Hydro PPA, it is also important to note that the figure reflects PPA Tranche 1 Energy available to FBC up to the maximum of 1,041 GWh. In the portfolio analysis, discussed in Section 9, the portfolio model will optimize the amount of PPA Tranche 1 Energy with the other resource options available to FBC and, as a result, the maximum Tranche 1 Energy available may not always be selected within the various alternative portfolios. PPA Tranche 2 Energy is also available to FBC but at a much higher cost, as discussed in Section 5. Based on the supply-side resource options presented in Section 8.2, FBC expects that it would be able to build or contract for new energy resources at a lower cost than the PPA Tranche 2 Energy cost. For this reason, the energy LRB is presented here with only the PPA Tranche 1 Energy amount.

The PPA tranche 2 energy rate is set based on a proxy for BC Hydro's LRMC of new supply. Currently, the PPA Tranche 2 energy rate is $129.70 per MWh[68], which is tied to BC Hydro's proxy for long run marginal cost based on the BC Hydro 2008 Clean Power Call. However, BC Hydro's LRMC for energy has since been updated and is significantly lower than this as stated in BC Hydro's recent 2015 Rate Design Application Evidentiary Update on Load Resource Balance and Long Run Marginal Cost dated February 18, 2016. In this update BC Hydro states that the LRMC has shifted towards $85 per MWh from a range of $85 per MWh to $100 per MWh[69]. Therefore, FBC has assumed that the PPA Tranche 2 energy rate could be lowered to the BC Hydro LRMC value of $85 per MWh in the future and has treated this as a PPA Tranche 2 rate scenario. FBC has assumed this $85 per MWh value is adjusted for inflation and so does not increase in real terms. The following figure shows the base case $129.70 per MWh PPA Tranche 2 rate and the $85 per MWh rate scenario.

Table 8-4: Supply-Side Resource Options Unit Cost Summary

Resource Option	UEC ($/MWh)	UCC ($kW-year)
PPA Tranche 1 Energy	$47 - $56	N/A
PPA Tranche 2 Energy	$85 - $130	N/A
PPA Capacity	N/A	$96 - $115
Market Purchases	$34 - $64	$169 - $355
Wood-Based Biomass	$118 - $188	$663 - $774
Biogas	$77 - $101	$621 - $838
Municipal Solid Waste	$134	$1,031
Geothermal	$132 - $217	$857 - $1,506
Gas-Fired Generation (CCGT)	$82 - $100	$147 - $279
Similkameen Hydro Project	$202	$1,298
Gas-Fired Generation (SCGT)	N/A	$80 - $143
Pumped Hydro Storage	N/A	$217
Onshore Wind	$111 - $145	$1,219 - $1,618
Run-of-River Hydro	$87 - $150	$1,230 - $1,924
Solar	$169 - $184	$1,399 - $1,413

16.1 When would FBC expect the price of Tranche 2 energy to be lowered?

Response:

If BC Hydro uses a new LRMC that is approved by the BCUC for rate making purposes, then the BC Hydro rate schedule 3808 Tranche 2 energy rate should be updated shortly thereafter. FBC does not know when this may occur.

16.2 When will FBC be able to confirm the price of Tranche 2 energy?

Response:

Please refer to the response to CEC IR 1.16.1.

17. Reference: Exhibit B-1, page 104

> Furthermore, DSM levels higher than the High scenario create risks in terms of managing the LRB. DSM is neither available on demand nor as reliable as a supply-side resource option because DSM programs require voluntary participation by customers. Therefore, there is no guarantee that actual DSM program uptake will materialize as planned and an over-reliance on DSM could leave unexpected gaps in the LRB that still need to be filled to meet customer load requirements.

17.1 Please confirm that conservation and efficiency options, and DSM programs are continuously changing and improving.

Response:

Confirmed. DSM programs change over time in response to new technologies, changing market conditions and collaborating partner offers, amongst other drivers.

17.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.17.1.

17.2 Please provide a discussion of the types of programs, rate design or other options that are available to utilities to create DSM that is reliable and available on demand?

Response:

To the Company's knowledge the only DSM option that is both reliable and available "on demand" (i.e. dispatchable) are Demand Response (DR) type programs, which include load controls on equipment such as hot water tanks or price response load curtailments. The additional scope phase of the BC CPR will estimate FBC's DR potential.

17.2.1 Please discuss FBC's use, and planned use of any such options.

Response:

At this time, FBC does not have any plans to use such options.

18. Reference: Exhibit B-1, page 105

> FBC has taken into account a number of attributes when evaluating the various resource options. In addition to financial attributes (i.e. costs), these include operational/technical characteristics and environmental and socio-economic impacts, which are discussed in the following sections. Geographic diversity of resources is also a consideration given that all of the generation plants FBC owns are located in the Kootenay region whereas most of the load and expected load growth is in the Okanagan region. Locating new generation resources closer to the primary load centres would help mitigate risks relating to transmission disruptions and reliability in the future.

18.1 What steps, short of new generating resources, is FBC taking to mitigate risks relating to transmission disruptions and reliability in the future? Please discuss.

Response:

FBC maintains transmission system reliability with regular inspection of transmission system equipment and regular maintenance programs. Replacement and upgrades of aging infrastructure are also part of the capital program. Section 6.3 of the LTERP discusses the projects that will mitigate the risks relating to transmission. Locating generation resources close to the load may be a cost-effective alternative to transmission reinforcement if and when the need for this arises in the future.

19. Reference: Exhibit B-1, page 111 and page 112

> Relying on market purchases over the long term, however, can be risky in terms of price and supply availability. While there are market price forecasts for future electricity prices, there is no guarantee that market prices will remain at these levels given the degree of price volatility and uncertainty in the marketplace. This is why FBC has presented varying market price forecast scenarios in Section 2.5. There is also no guarantee that FBC will be able to access market supply reliably, especially if there is no access to long term firm transmission (as discussed in Section 5.5). Therefore, FBC does not believe that market supply can be relied on as a long-term resource option.

19.1 Please provide any risk analysis has FBC has done with regard to reliance on market purchases.

Response:

FBC has not completed any formal risk analysis. FBC's view of the market risk is based on discussions with market participants, review of other regional utilities' resource plans, attendance at relevant industry conferences and forums and historical knowledge of the power markets.

19.2 Please provide market price forecasts for future electricity prices with the source and compare these to BC Hydro's forecast for High Load hours and Low Load hours.

Response:

In Figure 2-9, Section 2.5 of the LTERP, FBC provides varying market price forecast scenarios. These scenarios were based on prices shown in the Northwest Power and Conservation Council Seventh Power Plan, Chapter 8, and were given in 2012 $US/MWh. For use in the 2016 LTERP, prices were converted to real 2015 $CAD/MWh using exchange and inflation rates per LTERP Section 2.5.5 and transmission costs per Section 2.5.6.

Figure 2-9 has been updated as Figure 1 below to include BC Hydro's forecast for all hours as provided in the BC Hydro 2013 Integrated Resource Plan. For equal comparison, prices were converted to $CAD/MWh using exchange and inflation rates per LTERP Section 2.5.5. The data in Figure 2-9 has also been provided in tabular form below.

Figure 1: Mid-C Electricity Annual Price Forecasts, NPCC and BC Hydro

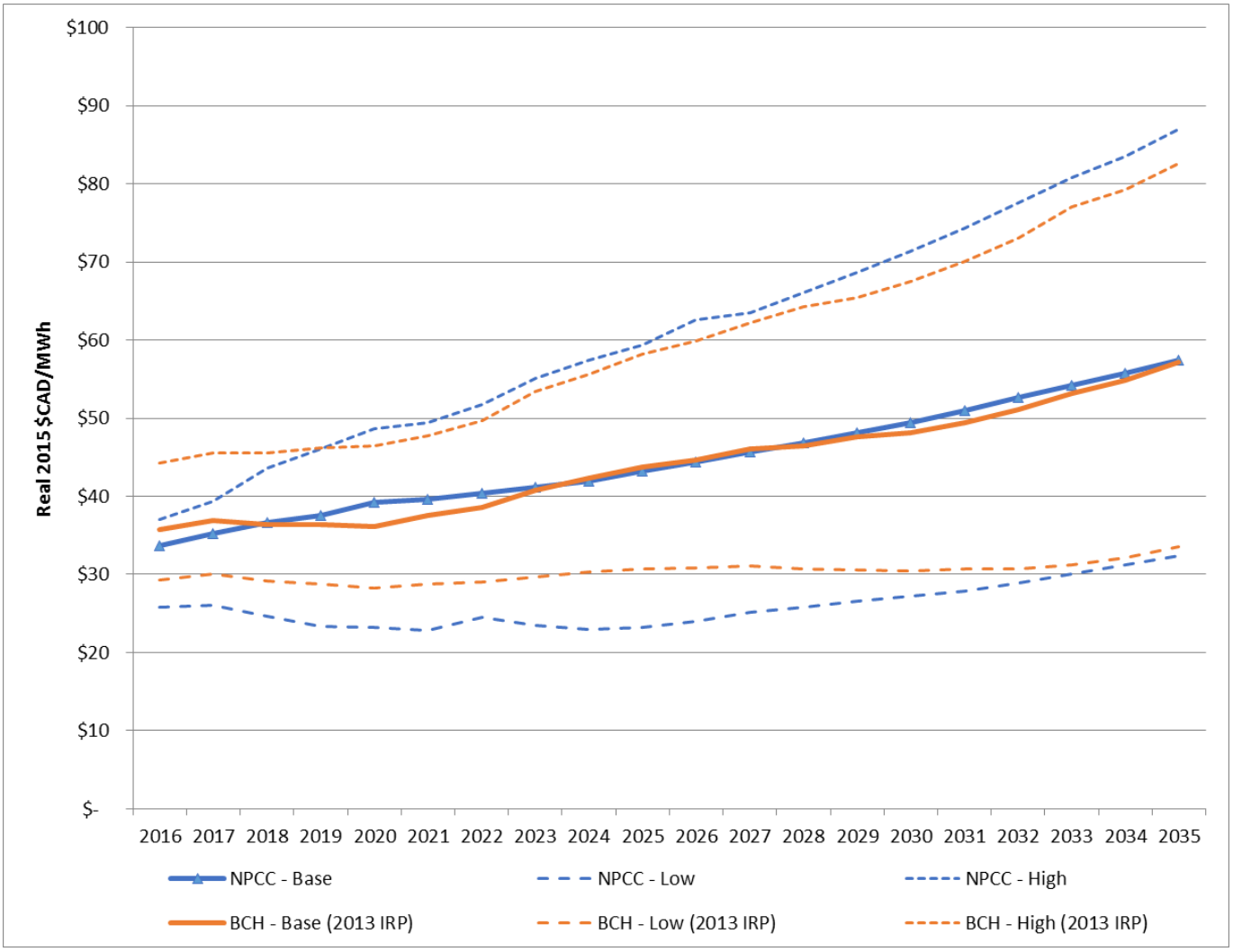


Table 1: Mid-C Electricity Annual Price Forecasts, NPCC and BC Hydro

2015 Real $CAD/MWh	BCH - Base (2013 IRP)	NPCC - Base	BCH - Low (2013 IRP)	NPCC - Low	BCH - High (2013 IRP)	NPCC - High
2016	$35.71	$33.63	$29.34	$25.79	$44.29	$37.07
2017	$36.95	$35.19	$30.00	$26.08	$45.54	$39.29
2018	$36.39	$36.69	$29.14	$24.64	$45.52	$43.62
2019	$36.44	$37.53	$28.76	$23.33	$46.20	$46.00
2020	$36.15	$39.19	$28.28	$23.17	$46.48	$48.59
2021	$37.53	$39.65	$28.82	$22.86	$47.78	$49.45
2022	$38.55	$40.42	$29.08	$24.48	$49.70	$51.79
2023	$40.73	$41.19	$29.72	$23.54	$53.41	$55.04
2024	$42.27	$41.95	$30.36	$23.02	$55.59	$57.40
2025	$43.81	$43.17	$30.74	$23.19	$58.15	$59.42
2026	$44.70	$44.41	$30.87	$23.94	$59.82	$62.54
2027	$46.11	$45.66	$31.13	$25.12	$62.25	$63.46
2028	$46.50	$46.90	$30.74	$25.84	$64.30	$66.01
2029	$47.65	$48.15	$30.61	$26.53	$65.45	$68.67
2030	$48.16	$49.39	$30.48	$27.19	$67.50	$71.38
2031	$49.44	$50.99	$30.74	$27.83	$70.06	$74.30
2032	$51.11	$52.59	$30.74	$28.96	$73.01	$77.51
2033	$53.16	$54.18	$31.25	$30.09	$76.98	$80.79
2034	$54.82	$55.78	$32.15	$31.22	$79.29	$83.56
2035	$57.13	$57.38	$33.56	$32.35	$82.62	$86.94

19.3 Please provide historical prices for the market prices on a monthly basis over the last 10 years.

Response:

Please refer to Table 1 below, which provides the historical average Mid-C day-ahead prices on a monthly basis in $USD/MWh.

Table 1: Historical Average Mid-C Prices

$USD/MWh	January	February	March	April	May	June	July	August	September	October	November	December
2007	$50.64	$56.45	$35.65	$40.69	$46.05	$45.92	$53.08	$49.91	$49.04	$57.59	$59.98	$61.83
2008	$70.06	$67.81	$71.49	$87.13	$52.36	$21.75	$59.53	$65.39	$53.51	$48.86	$46.30	$54.79
2009	$37.61	$37.87	$29.45	$20.41	$21.16	$17.48	$31.11	$34.31	$32.09	$40.32	$32.18	$51.23
2010	$43.74	$42.30	$37.14	$35.10	$27.43	$10.80	$29.63	$34.33	$32.15	$29.93	$32.62	$32.34
2011	$26.36	$22.71	$16.95	$20.77	$15.31	$13.37	$19.60	$28.19	$31.47	$25.71	$30.56	$30.31
2012	$24.75	$23.36	$16.33	$9.38	$5.94	$4.91	$11.94	$24.88	$24.30	$30.50	$27.73	$24.14
2013	$27.22	$28.38	$31.66	$25.92	$23.65	$27.63	$34.19	$33.24	$34.29	$34.33	$33.56	$50.76
2014	$40.24	$68.98	$26.69	$25.29	$21.51	$25.84	$36.69	$36.32	$36.30	$29.78	$33.43	$25.23
2015	$21.69	$15.47	$17.11	$18.88	$25.33	$32.10	$33.82	$27.92	$25.17	$22.56	$20.58	$20.41
2016	$22.35	$16.28	$11.49	$9.57	$12.53	$19.12	$26.70	$30.33	$26.23	$21.25	$17.17	$29.77

19.4 Please discuss the causes of uncertainty in the marketplace.

Response:

In the electricity marketplace, wholesale prices generally reflect the factors driving supply and demand. Supply covers both generation and transmission, as both must be available to meet demand at any given time. Major supply components that can cause uncertainly in the marketplace include generation fuel prices and availability, transmission capacity and constraints, capital costs and operating characteristics of power plants. On the demand side, the main factors that can cause uncertainty include weather, economic activity, and efficiency of consumption.

20. Reference: Exhibit B-1, pages 32, 35,36, and 112

2.4.1 Market Price Environment

Regional market electricity prices continue to be highly correlated with regional natural gas prices. This is largely because natural-gas fired power plants are often the marginal generating unit for generating electricity. Natural gas prices continue to remain low relative to historical values prior to the shale gas surge after 2008. Advances in drilling technology and cost reductions for producers have led to an abundance of low-cost shale gas in North America and increases in shale gas production are only expected to continue. Low gas prices are providing opportunities for increased natural gas use, particularly in power generation, LNG exports, and the transportation sector. Natural gas supply has kept up with this increased demand, keeping prices at low levels.

As shale gas production in the northeastern portion of the U.S. expands, there will be less of a need to export western produced gas to the eastern consuming regions. This fundamental change will create a surplus of available natural gas in the western portion of the continent and help sustain the regional price advantage for consumers in the Pacific Northwest.

The West Coast energy crisis of the early 2000s resulted in an expansion of new gas-fired combined-cycle power plants in order to meet the market's capacity deficit. As a result, the Mid-Columbia (Mid-C) power market[35] has generally been in an energy and capacity surplus since the mid-2000s. This provides a cost effective way for utilities in the region to meet their load as it has generally been cheaper to buy energy and capacity in the wholesale market rather than building new generation plants[36]. The majority of the electric utilities in the Pacific Northwest region rely on wholesale market purchases to some extent (see Comparison Table in Appendix C).

Due to the Pacific Northwest's proximity to natural gas producing regions in the WCSB and the U.S. Rocky Mountain region along with low natural gas prices, gas-fired power plants have become a low-cost alternative for power generation. Gas-fired generation is expected to make up the capacity shortfall caused by coal retirements, intermittent resources, and load growth. This will further strengthen the interdependency between natural gas and electricity prices in the Pacific Northwest region.

8.2.6 Expiring Energy Purchase Agreements

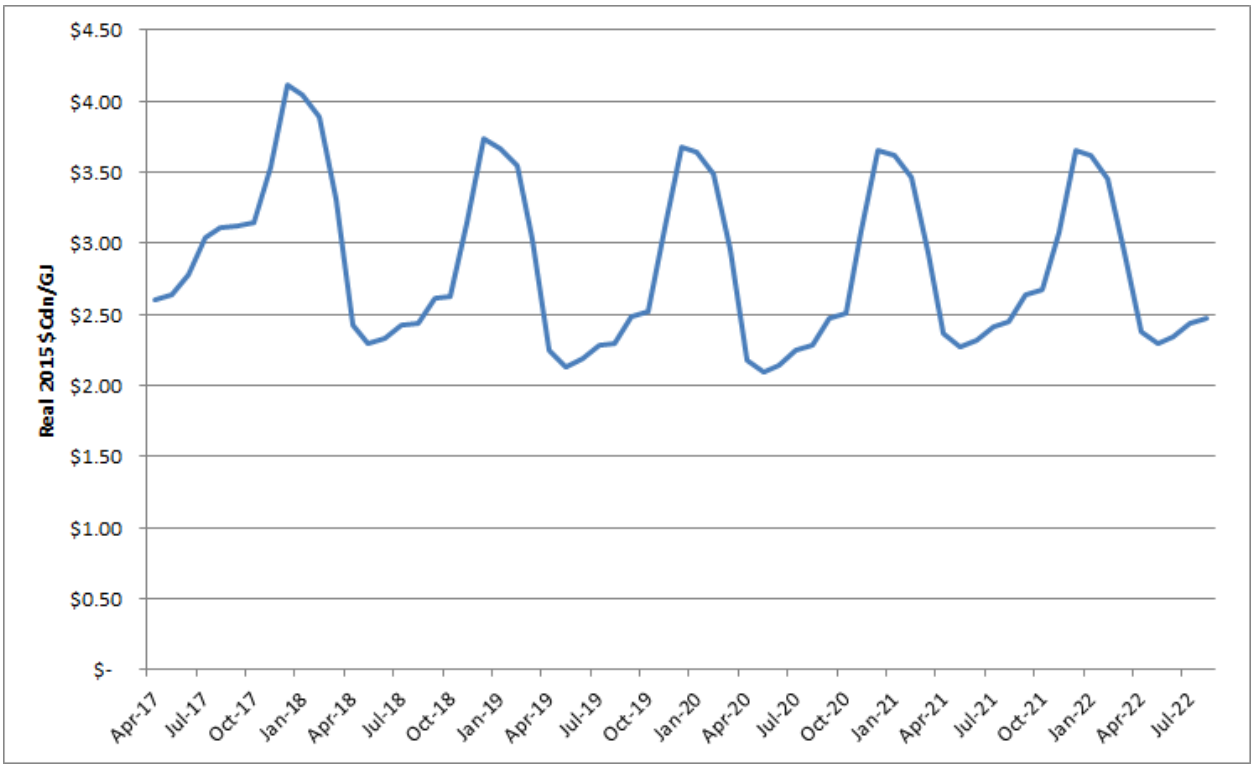
Energy currently provided to BC Hydro from IPPs under Electricity Purchase Agreements (EPAs) may become available to the market when these EPAs expire. In its 2013 IRP, BC Hydro has assumed, for planning purposes, that about 50 percent of its bioenergy EPAs will be renewed, about 75 percent of its run-of-river EPAs that are up for renewal in the next five years will be renewed, and that all of its other EPAs will be renewed. BC Hydro also amended its Standing Offer Program rules to specifically exclude generators with expiring EPAs. BC Hydro's F2017-F2019 Revenue Requirements Application also addresses expiring EPAs. Fourteen of BC Hydro's existing EPAs with IPPs are expiring by the end of fiscal 2019. Consistent with the approved 2013 Integrated Resource Plan (IRP), BC Hydro continues to assume renewal of 50 percent of the energy and capacity contributions from biomass EPAs and 75 percent from the run-of-river hydroelectric EPAs that are due to expire within the remaining years of the 10 Year Rates Plan the BC government announced in 2013.

BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. However, there may be opportunities for FBC to acquire power from the other facilities on a cost-effective basis. In addition, BC Hydro will need to address expiring EPAs after 2019. FBC will continue to monitor the BC Hydro contract renewals for any resource option opportunities.

20.1 Please provide the forward price curve for natural gas.

Response:

The following figure shows a recent forward market price curve (as of March 7, 2017) for the Sumas market hub.



21. Reference: Exhibit B-1, page 117

> FBC currently accesses market supply to complement its existing resources with reliable and low-cost power. There is no indication at this time that market supply will increase significantly in price or that FBC will not be able to access it reliably over the next ten years. However, market conditions can change over time and market prices and access could change in the future. FBC's base case assumption is that it will be able to access low-cost and reliable market supply for the next ten years, out to 2025. After this time, FBC has assumed that it will become self-sufficient, with incremental supply coming from its own generation and/or long-term contracts from B.C. suppliers. This also provides consistency with the *CEA* objective of achieving electricity self-sufficiency. As sensitivity cases, FBC has developed portfolios that do not include self-sufficiency within the planning horizon (i.e. long term market reliance) and self-sufficiency by an earlier date of 2020. FBC has also modelled the impacts of higher market power and carbon prices based on the price forecasts and scenarios provided in Section 2.5.

21.1 Under what circumstances would FBC consider not achieving moving toward self-sufficiency by 2025? Please explain.

Response:

In the next long term resource plan, FBC may consider delaying the self-sufficiency target of 2025 if that can be accomplished while meeting the objectives of the long term resource plan at that time. The objectives of the current LTERP are discussed in section 1.3 of the LTERP. If FBC is able to continue to purchase market power cost-effectively, securely and reliably beyond 2025, then it may consider extending the self-sufficiency target further out in time.

21.2 Please describe the types of energy market conditions that would support the assumption that FBC will become self-sufficient after 2025.

Response:

Market conditions that would support FBC's plan to become self-sufficient after 2025 would include if the market cannot be reasonably expected to deliver cost-effective, secure and reliable energy to the FBC service area. This could be the result of reduced transmission availability, increased market costs, or reduced liquidity in the market. However, as discussed in the response to CEC IR 1.21.1, any decision on the self-sufficiency target past 2025 will be considered in FBC's next long term resource plan and will have to be consistent with the objectives of that plan at the time.

21.3 Please describe the types of energy market conditions that would support the continued reliance on market supply for some portion of FBC's energy beyond 2025.

Response:

Market conditions that would support continued reliance on market supply beyond 2025 would include if the market could be reasonably expected to continue to deliver cost-effective, secure and reliable energy to the FBC service area. However, as discussed in the response to CEC IR 1.21.1, any decision on the self-sufficiency target past 2025 will be considered in FBC's next long-term resource plan and will have to be consistent with the objectives of that plan at the time.

21.4 Please provide an overview of FBC's plan to develop incremental supply with time frames and high level expected costs, given that many years are required to put this in place.

Response:

Please refer to the responses to CEC IRs 1.26.2 and 1.26.2.1.

22. Reference: Exhibit B-1, page 117 and page 100

> and help reduce their electricity bills. The maximum DSM level is based on meeting 89 percent of annual average forecast load growth for customers' energy requirements with DSM. The High DSM level is FBC's proposed DSM offset level while the Base DSM level is close to FBC's current level of DSM.

Table 8-2: Key DSM Scenario data

Category	DSM Scenario			
	Low	Base	High	Max
Annual Savings, GWh				
Average per annum ('18-'35)	20	26	31	36
% of load growth ('18-'35)	50%	66%	77%	89%
Total (2016 to 2035)	407	523	602	686
Resource Cost, 2016 $/MWh				
Incremental cost incl. program costs	$45	$88	$104	$114

22.1 Please describe the types of programs and activities FBC will likely undertake to raise the DSM program's current level close to Base DSM to High DSM level.

Response:

The DSM Scenarios utilize increasingly costly measures, as is indicated in the escalating incremental resource costs. The measures are drawn from the BC CPR measure list and address the end-uses of a cross-section of sectors, segments and new/retrofit/behavioural opportunities. The measures have not yet been organized into specific programs that will be added as the DSM Scenarios are escalated.

The 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not determined. FBC anticipates filing its next DSM expenditure schedule, for 2018 onwards, later this year.

22.2 Does FBC have savings from Rate Designs, and if so, please identify them and their incremental costs.

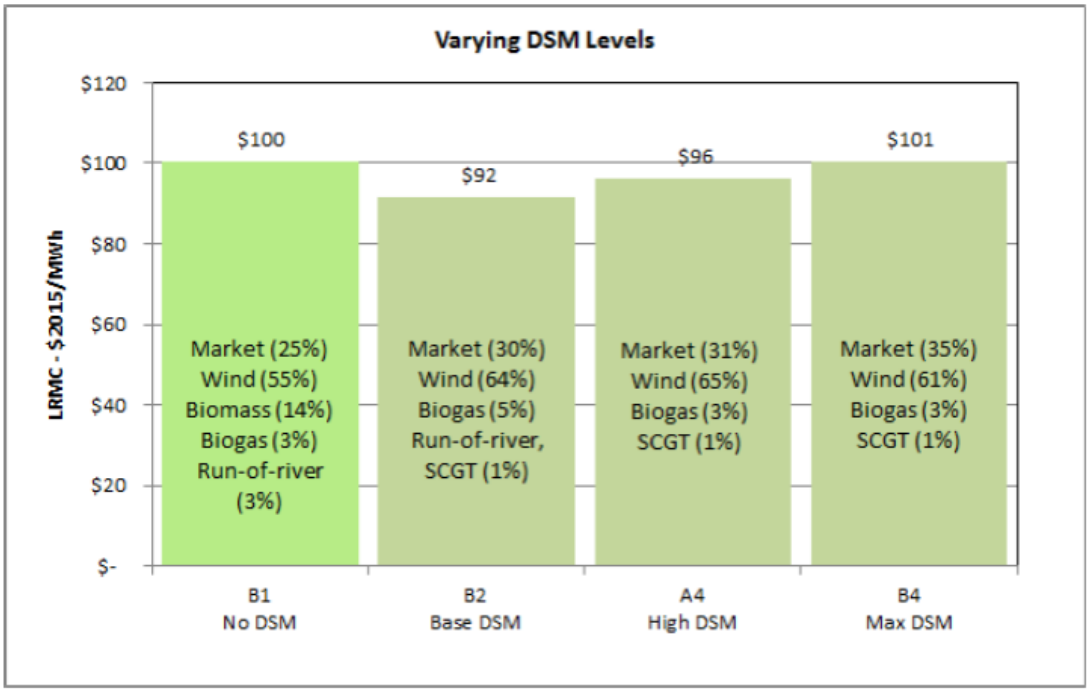
Response:

FBC has previously reported to the Commission that the Residential Conservation Rate delivered conservation results of between 36 and 46 GWh, or 2.6 to 3.3 percent of total system requirements.[5]

[5] FBC RCR Report July 1, 2012 to June 30, 2014, Page 20.

23. Reference: Exhibit B-1, page 119

Figure 9-1: Portfolios with Different DSM Levels



The first column (B1) represents the portfolio of clean or renewable resources without any DSM, which, as described above, is used to determine the LRMC for the purposes of evaluating cost effective DSM (per the DSM Regulation). The LRMC for this portfolio is $100 per MWh and it includes wind, biomass, biogas, and run-of-river resource options as well as some market purchases out to 2025.

The other columns (B2 to B4) show three portfolios with different levels of DSM and which include the requirement that the total portfolio mix meet the *CEA* objective of at least 93 percent clean or renewable resources. These portfolios have LRMC values that range from $92 per MWh to $101 per MWh and all include market access to 2025, wind, biogas and minor contributions from SCGT. The least-cost portfolio (B2) includes the base amount of DSM while the highest cost portfolio (B4) includes the maximum level of DSM. This is because the cost of the higher DSM offset levels is greater than alternative supply-side resource options, including lower-cost market supply and PPA Tranche 1 Energy.

23.1 Please provide the expected costs of each of the energy resources included in this analysis on a $/MWh basis.

Response:

The following are the UECs[6] ($ per MWh) of the resources contained in portfolios B1, B2, A4, and B4.

		Portfolio			
Resource Type	**Resource Name**	**B1**	**B2**	**A4**	**B4**
DSM	Base DSM		$88		
	High DSM			$104	
	Max DSM				$114
PPA	PPA Tranche 1[7]	$50	$50	$50	$50
New Resources	Biogas1	$77	$77	$77	$77
	Biogas2		$101		
	Biogas3	$88	$88	$88	
	Biogas4	$100	$100		
	Wind2				$119
	Wind3		$113	$113	
	Wind4	$111			
	Wind6	$145			
	RoR2	$150	$150		
	RoR4	$136			
	Biomass1	$118			
	Biomass3	$188			
	SCGT1		N/A	N/A	
	SCGT2				N/A
Market	Market	$50	$50	$50	$50

23.2 Please briefly describe the criteria under which the component resources were selected and how the portfolios were developed.

[6] UECs were derived using a 6 percent discount rate, are stated in 2015$, and are based on the reliable energy each specific resource is presumed capable of producing on an annual basis. For additional details, please refer to the Resource Options Report in Appendix J of the LTERP.

[7] PPA energy only.

Response:

FBC developed a resource portfolio model that incorporates an optimization routine to find the lowest present value cost of satisfying the forecast load requirements given a set of constraints. Specifically, FBC is using a Mixed Integer Linear Programming model.

Each portfolio, with the exception of portfolio B1, contains a level of DSM, namely Base DSM, High DSM, or Max DSM. The level of DSM resources is manually set within each portfolio. The optimization routine then determines the potential utilization of PPA, when and what new resources could be acquired from the available resource options and, once a new resource is acquired, how much energy could be optimally generated.

The available supply-side resource options were determined through the resource options collaboration process with BC Hydro as discussed in Appendix J of the LTERP. The optimization model additionally determines the potential utilization of the market when market access is permitted. To determine the optimal mix of resources the optimization routine includes certain broad criteria, or constraints, for the solution to be practical and reflective of the desired portfolio attributes (e.g. minimum 93 percent clean, self-sufficiency, etc.). These constraints include parameters of the PPA, practical limitations on new resource options, consideration of *CEA* objectives, and limitations on market access.

The optimal set of selected resources is able to meet both the forecast capacity and energy load requirements for each month of each year in the planning horizon. This takes into account FBC's existing resources and planned level of DSM savings associated with the specific portfolio. Each portfolio was then evaluated for PRM requirements. In the event PRM requirements were not met, the portfolio was re-optimized with additional capacity requirements for PRM purposes as per the process described in Section 3.2 of Appendix L of the LTERP.

23.3 Please identify which energy resources included in the portfolios are not yet developed or available to FBC.

Response:

Incremental new resource options selected within the portfolios were derived from the Resource Options Report in Appendix J of the LTERP. Each of the viable resource options identified is considered available, but not developed.

23.4 Are the renewable energy sources located and/or expected to be located within FBC service territory and offer direct access to FBC? Please explain.

Response:

FBC's portfolio modelling considered renewable resources in both its service territory as well as BC Hydro's service territory. Generation development opportunities are not evenly distributed across the province. If a competitive generation project is located in BC Hydro's service territory, it is a resource option for FBC.

In the portfolio modeling, if a resource considered was located in BC Hydro's service territory it was assumed that the powerplant would interconnect to the BC Hydro system and that the power would be delivered to the FBC service territory through BC Hydro's lines. BC Hydro's tariff wheeling and losses costs were included in the energy cost.

23.4.1 If the renewable resources are not in FBC's service territory and would have to be accessed through the BC Hydro transmission system – for example, energy from wind projects in northwest BC, what additional costs would be incurred, and how would the final costs compare to electricity purchased from BC Hydro under the PPA?

Response:

Please refer to the response to CEC IR 1.23.4.

The final cost ranges can be seen in Table 8.1 of the LTERP.[8] In all cases, BC Hydro PPA Tranche 1 energy is less expensive than a greenfield renewable plant, whether it is located in the FBC service territory or BC Hydro service territory. As can be seen in the ranges of energy prices in the table, there are scenarios where a greenfield renewable plant's UEC may be lower than the BC Hydro PPA Tranche 2 energy rate.

23.5 Please provide an estimate of the total costs and benefits for each of the Base DSM, High DSM and Max DSM maximizing the use of market purchases.

[8] LTERP, Section 8, table 8.1, page 96.

Response:

The LRMC can be used as a metric to compare the costs and benefits of varying DSM levels. FBC has interpreted 'maximizing the use of market purchases' as removing the self-sufficiency target in 2026. The following table shows the LRMC of portfolios with varying levels of DSM and without a self-sufficiency target in the planning horizon.

Table 1: No Self-Sufficiency, Varying Levels of DSM

Portfolio	LRMC
Base DSM, No Self-Sufficiency	$72 per MWh
High DSM, No Self-Sufficiency (Portfolio A1)	$76 per MWh
Max DSM, No Self-Sufficiency	$80 per MWh

23.6 In the case of the SCGT plant described, please provide details on the size and cost of the plant and time required to design, permit and construct.

Response:

Design and permitting for the SCGT plant is estimated to be two years. Construction would be about 14 months. Please see the following table for the size, cost, service territory and earliest availability of the plant.

Name	Service Territory	Nameplate Capacity (MW)	UEC ($/MWh)[9]	UCC ($/MW-yr)[10]	Earliest Availability
SCGT1	FBC	48	$ N/A	$143	2020

[9] Assumes a 6 percent discount rate, Sumas Gas Price Forecast "Base" and BC Carbon Price Scenario "Base" as per Appendix D of LTERP.

[10] Assumes a 6 percent discount rate.

24. Reference: Exhibit B-1, page 120

> The results show that continued access to the market throughout the planning horizon, without any self-sufficiency requirement, provides a lower LRMC than portfolios where self-sufficiency is required by 2020 or 2025. This is because of the low cost of market supply relative to the cost of other resource options. The LRMC for this portfolio (A1) is $76 per MWh and increases to $81 per MWh in the scenario where higher market and carbon prices are assumed (A2). In the portfolio where there is no market access after 2020 (A3), the LRMC is the highest at $104 per MWh. In this case, the portfolio analysis indicates that FBC would require a new resource, a CCGT plant, as early as 2021. The LRMC of the portfolio where there is no market access after 2025 (A4) falls in between at $96 per MWh. This portfolio includes incremental wind and biogas resources after 2025. It also includes a SCGT plant, which is not required until 2032, and is needed only for low amounts of energy and capacity.
>
> Due to the risks of relying on market access indefinitely into the future (as discussed in Section 5.5 and 8.2.4), FBC believes that self-sufficiency at some point in the planning horizon is a more prudent approach to resource planning. Self-sufficiency by 2020 results in a significantly higher LRMC and would mean that FBC would need to secure incremental resources within the next few years to meet the 2020 target. Self-sufficiency by 2025 allows more time to plan for new resources and to assess the LRB, as well as market conditions, at the time FBC prepares its next long term resource plan. This is a more balanced approach to market access. Self-sufficiency is also a B.C. energy objective in the *CEA*.

24.1 When does FBC expect to prepare its next Long Term Resource Plan? Please provide approximate time frames for the commencement, preparation and delivery.

Response:

In its response to BCUC IR 1.41.5, FBC stated that it expects to submit its next long term electric resource plan in approximately five years from the submission date of the 2016 LTERP, or approximately November 2021. Planning and preparation to meet this submission date would likely begin 18 months prior in mid-2020.

24.2 Please confirm the CEC's understanding that the plan to allow for self-sufficiency by 2025 facilitates greater flexibility for FBC, in that it could choose to alter its course of action and make the determination to rely longer on market supply if market conditions appear favourable during the preparation for the next Long Term Resource plan.

Response:

Confirmed.

24.2.1 If yes, does planning for self-sufficiency at 2025 result in any extra costs if, during the next LTERP, FBC were to decide to rely on market supply, or is there effectively no additional costs for this flexibility? Please discuss and provide quantification of any costs that are incurred.

Response:

There is no extra cost associated with targeting self-sufficiency in 2025 or beyond, as FBC is not planning to acquire any new resource between now and the filing of its next long term resource plan. FBC will fully review the 2025 self-sufficiency target in its next long term resource plan, which it expects to file in 2021.

24.3 Would planning for self-sufficiency at 2030 provide any greater flexibility to FBC, or does the 2025 self-sufficiency planning horizon provide full flexibility? Please explain why or why not.

Response:

Planning for 2025 self-sufficiency provides full flexibility as compared to a 2030 self-sufficiency target, because the 2025 target allows time to plan for new resources and to assess the Load-Resource Balance, as well as market conditions, in its next long term resource plan, before being required to make any resourcing changes.

24.3.1 If FBC were to decide to rely on market supply beyond 2025, what would be the latest time at which it could cost-effectively make that determination?

Response:

The latest time at which FBC could cost-effectively make that determination would be prior to when FBC would need to make a decision on alternate supply arrangements, which is not known at this time, but not expected to occur prior to the filing of FBC's next long term resource plan. The 2025 self-sufficiency target and the timing of any potential alternate supply arrangements will be reviewed in the next long-term resource plan.

25. Reference: Exhibit B-1, page 125 and 126

> Note that for portfolios C1, A4 and C4, market purchases are selected until 2025 and incremental supply-side resources are not required until at least 2026. Market purchases are selected because they are lower cost than the PPA Tranche 1 Energy, at least for the first few years of the planning horizon. For portfolio A1 with no self-sufficiency, market purchases are selected throughout the 20 years because market power is lower cost than the other resource options.

Table 9-2: Attributes of Portfolios Considered for Preferred Portfolio

Portfolio		Incremental Resources	LRMC ($/MWh)	Max % Non-Clean BC Resources (based on energy)	GHG emissions produced in BC (tonnes CO2e)	Full-Time Equivalents per year	Geographic Resource Diversity
A1	No Self-Sufficiency	Market (97%) Biogas (3%)	$76	0.0%	0	14	Low
C1	93% Clean with CCGT	Market (51%) CCGT (48%) Biogas (1%)	$91	3.9%	189k	164	Medium
A4	93% Clean with SCGT	Market (31%) Wind (65%) Biogas (3%) SCGT (1%)	$96	0.2%	3k	145	High
C4	100% Clean BC Resources	Market (31%) Wind (65%) Biogas (3% Biomass, Solar (1%)	$98	0.0%	0	216	Medium

25.1 Portfolio A1 includes 0.0% Non-Clean BC resources. Please confirm that A1 represents the lowest possible LRMC that FBC could create.

Response:

Not confirmed. Remaining consistent with the approach taken to complete the portfolio analysis presented in Section 9 of the LTERP, (e.g. consistent operational and resource constraints, attributes, price assumptions, etc.), the lowest LRMC portfolio FBC could create is similar to portfolio A1, with the expectation of incorporating a "Base DSM" program, as opposed to a "High DSM" program, and no self-sufficiency target. The LRMC of this portfolio is $72 per MWh.

25.1.1 If not confirmed, please provide details of the lowest LRMC portfolio that FBC can create.

Response:

Please refer to the response to CEC IR 1.25.1.

26. Reference: Exhibit B-1, page 128

> The preferred portfolio includes several types of resources such as market purchases, SCGT, wind and biogas. Increases in market gas prices would not have a material effect on the costs of the SCGT given that it is used for limited amounts of energy and capacity for peaking and reliability purposes. Increases in market power prices, however, could have a more significant impact on the portfolio costs. This was discussed in Section 9.4.3, above, where the impacts of higher market prices increased the LRMC value from $96 per MWh (A4) to $98 per MWh (C3). With higher market prices, FBC selected more energy from wind generation and less from the market for the portfolio.
>
> Section 4 discusses load scenarios and the potential for increased load due to fuel switching, EVs and the addition of new large loads to the FBC system. While the load increases from fuel switching from gas to electricity and EVs would likely occur gradually over time, a new large load addition, from a datacentre or hospital for example, could occur much more quickly. In this scenario, discussed in Section 9.4.4, FBC could rely on more market purchases but may also be required to add new resources such as wind, solar and gas-fired generation. Depending on the timing of the additional load requirements, FBC would have to accelerate the acquisition or building of new generation before 2026, when new resources are otherwise required based on the reference case load forecast. The inclusion of SCGT in the preferred portfolio does provide

26.1 What criteria will FBC use to determine whether to build or acquire new generation?

Response:

FBC will look at both building and contracting its power needs. Criteria for the evaluation will be developed at the time of the procurement, but will include energy and/or capacity cost and the LTERP objectives. Any generation procurement will be subject to Commission review.

26.2 How much lead time is required to initiate a project to build new generation, including siting, design, permitting and construction?

Response:

The lead time needed to get to commercial operation date (COD) would depend on the generation type, size, and who is developing the project (i.e. an Independent Power Producer (IPP) versus FBC). For example, a small SCGT would require about 14 months to construct. A large SCGT would require 24 to 32 months to construct. Projects greater than 50 MW will have to go through a potentially longer federal environmental assessment process, while projects under 50 MW go through the Provincial Environmental Assessment Office.

Utilities, including IPPs, are required under the section 45 of the *UCA* to apply for a Certificate of Public Convenience and Necessity to construct a power plant. Unlike IPPs selling to BC Hydro, IPPs planning to sell to FBC are not exempted by ministerial order from regulation as a public utility under Part 3 of the *UCA*.

Note that many of the better project opportunities in B.C. already have IPP proponents with an Investigative Licence for the site and that are investing in pre-construction development work in anticipation of future calls. A 100 MW on-shore wind project that only has its Investigative Licence could take five years for completion of the necessary work to achieve a COD. However, if an IPP has already installed a meteorological tower, has one year's worth of wind data and has done the field studies, the project may only need another 3.5 years to do the permitting and engineering required to get to COD.

26.2.1 When will FBC make the decision to build or acquire new generation?

Response:

The Load-Resource Balance (LRB) presented in this LTERP indicates that under the reference case, new supply-side resources are not required until 2026. However, actual load requirements and DSM program uptake by customers may not match the reference case, meaning that resources may be needed sooner or later than expected. As part of its ongoing resource planning activities, FBC will continue to assess the LRB on a periodic basis to see if any changes in resources might be required.[11]

If the LRB does not change, FBC would start to evaluate its options in 2021, at the time of its next long term resource plan. This would provide FBC with enough lead time to assess the updated LRB and available resource options and costs before any new resources may be required by 2026.

[11] LTERP, Section 3, action item 3, page 140.

27. Reference: Exhibit B-1, page 137

> **10.4 *DIALOGUE AND ENGAGEMENT WITH FIRST NATIONS***
>
> FBC strives to develop and build mutually beneficial working relationships with First Nations communities. Understanding, respect, open communication and trust continue to be FBC's aim when working with First Nations groups throughout the province.
>
> FBC works to ensure that First Nations' interests are represented in the Company's various stakeholder engagement initiatives. The RPAG includes a member that represents B.C. First Nations, which ensures that First Nations play an active role in the ongoing resource planning process. In addition, First Nations representatives from within the electric service area, including the Okanagan Nation Alliance, the Ktunaxa Nation, and the Secwepemc Nation, were invited to attend the Community Consultation workshops throughout the preparation of this LTERP.
>
> FBC also met with representatives of the Ktunaxa Nation in Cranbrook on October 31, 2016. In this meeting, FBC provided an overview of its long term gas and electric resource planning. During the discussions, the Ktunaxa Nation expressed its concerns about not having access to lower-cost energy given the current unavailability of natural gas for space and water heating and a primary reliance on more expensive electricity for space and water heating. FBC will continue to engage with the Ktunaxa Nation to explore options to help meet its energy needs.

27.1 What, if any, are the major concerns that First Nations have identified with respect to the ongoing resource planning process?

Response:

During the Resource Planning Advisory Group (RPAG) workshops, one member representing First Nations' interests commented that First Nations should be involved in providing power to FBC in the future when FBC is considering resource options. As discussed in Section 8.2.9 of the LTERP, if new supply-side resources are needed in the future, FBC would consider generation projects that promote First Nations and community development if they are competitive with the cost of alternative resources and meet FBC's LTERP objectives.

In addition, during the workshop held with the Ktunaxa Nation as discussed in Section 10.4 of the LTERP, there were concerns around the costs of heating with electricity in First Nations communities with no access to natural gas. There was also support for increased DSM measures rather than increased resource development that would directly affect lands within their traditional territory.

27.1.1 What activities will FBC undertake to ensure that these concerns are addressed?

Response:

FBC is actively working alongside First Nation members with targeted DSM programs to help reduce usage and costs within their communities.

Additionally, FortisBC Energy Inc. has been actively engaged with First Nation communities regarding opportunities to expand natural gas networks into their communities.

28. Reference: Exhibit B-1, Appendix J, pages 2 and 3

> FBC has also given consideration to the geographical diversity of its resource base, given that the generation resources owned by FBC are all located in the Kootenay region while most of its load requirements are in the Okanagan region.
>
> In addition to financial attributes, FBC considers a number of factors when evaluating its resource options. These include consistency with B.C. energy policy and resource attributes, such as operational characteristics and environmental impacts. Geographic diversity of resources is also a consideration given that all of the generation plants FBC owns are located in the Kootenay region whereas most of the load and recent load growth is in the Okanagan region. Locating new generation resources closer to the primary load centres would help mitigate risks relating to transmission disruptions and reliability in the future, and could reduce or delay the need for transmission upgrades in the future. Furthermore, a number of financial assumptions must be made in order to cost the resource options, such as gas and electricity market prices, BC Hydro electricity rates and the cost for carbon emissions. These are discussed in the following sections.

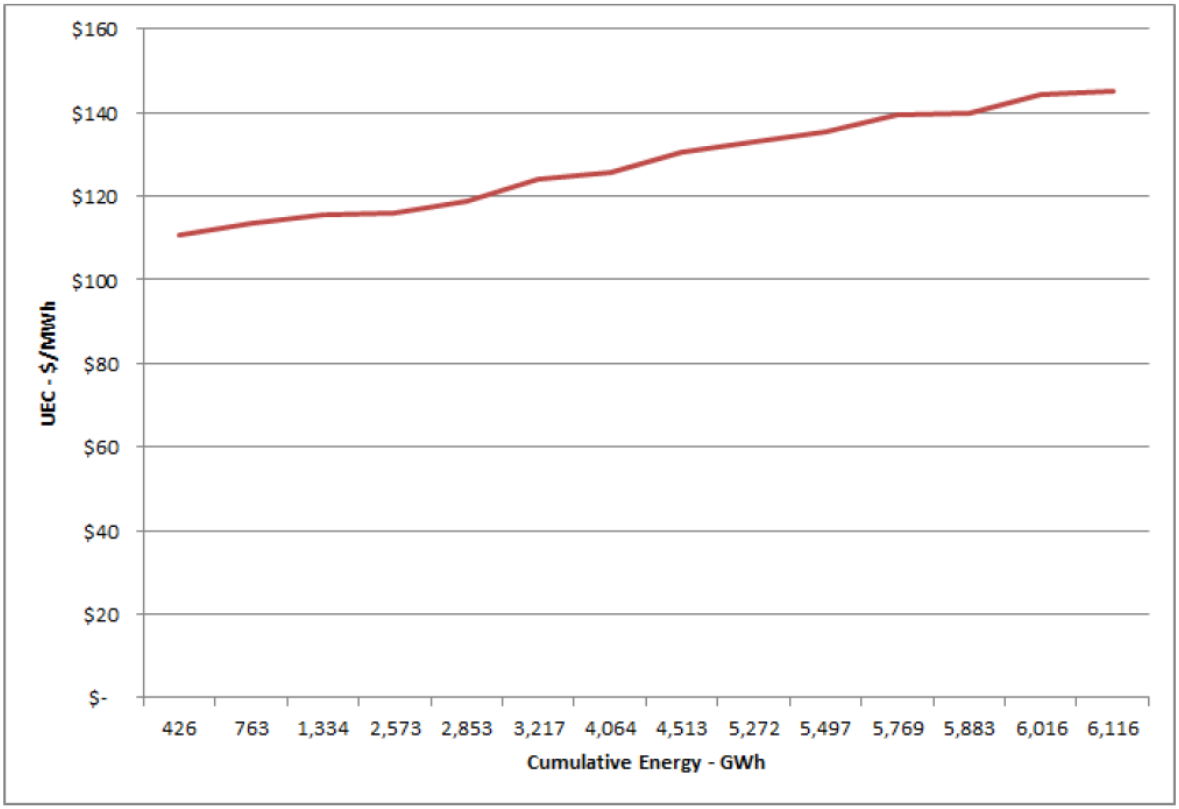
28.1 Are there benefits in terms of risk reduction from catastrophic events from have greater geographic diversity in its resources? Please explain why or why not.

Response:

Yes, there are benefits in terms of risk reduction from catastrophic events from having greater geographic diversity in resources. If all generation were to be located in one central location, one catastrophic event could potentially damage or shutdown all generation assets in that location. For example, a lightning and wind storm could come through a region causing all transmission lines to be out of service, which could cause all generation in the region to also be unavailable.

29. Reference: Exhibit B-1, Appendix J, page 32

Figure J3-19: Onshore Wind Supply Curve



FBC's collaboration with BC Hydro identified over one hundred potential wind projects throughout B.C., with many of them in northern B.C. FBC has evaluated a smaller subset of lower cost sites outside and within its service area for the purposes of this ROR. The supply curve for these lower cost projects is provided in the following figure.

29.1 Please identify the smaller subset/shortlist of the potential wind projects and their expected in-service date.

Response:

The following table shows the smaller subset list of the potential wind projects FBC used in its portfolio analysis. As not all of the wind projects were selected in the preferred portfolio, FBC has provided earliest availability for the projects instead of in-service date.

Name	Service Territory	Nameplate Capacity (MW)	UEC ($/MWh)[12]	UCC ($/kW-yr)[13]	Earliest Availability
Wind1	FBC	48	$140	$1,308	2021
Wind2	FBC	102	$119	$1,272	2021
Wind3	FBC	117	$113	$1,270	2021
Wind4	FBC	150	$111	$1,219	2021
Wind5	FBC	144	$124	$1,225	2021
Wind6	BC Hydro	32	$145	$1,564	2021
Wind8	BC Hydro	41	$144	$1,618	2021
Wind10	BC Hydro	74	$136	$1,413	2021
Wind11	BC Hydro	95	$139	$1,379	2021
Wind13	BC Hydro	150	$131	$1,333	2021
Wind14	BC Hydro	165	$115	$1,333	2021
Wind15	BC Hydro	240	$133	$1,436	2021
Wind16	BC Hydro	272	$126	$1,325	2021
Wind17	BC Hydro	344	$116	$1,393	2021

29.2 Please provide their locations of the on a map of BC.

Response:

Providing a map with the project locations would identify the specific projects considered in the portfolio analysis, disclosing commercially sensitive information. In the tables in the responses to CEC IRs 1.29.1, 1.30.1 and 1.31.1, FBC has instead provided more generalized information in which utility territory these projects are located.

29.3 Please provide the expected size and costs for each project.

Response:

Please refer to the response to CEC IR 1.29.1.

[12] Assumes a 6 percent discount rate.
[13] Assumes a 6 percent discount rate.

30. Reference: Exhibit B-1, Appendix J, page 33

> There is significant potential for run-of-river generation in B.C. and FBC's collaboration with BC Hydro identified over seven thousand possible sites. Most of the possible sites would not be considered economic at this time, however. For this ROR, FBC developed a smaller subset of the identified sites by selecting a sampling of cost-effective different-sized sites. The cost curves for these are provided in the following figure.

30.1 Please provide the smaller subset/shortlist of the potential run of river projects without specific identities and their expected in-service date.

Response:

The following table provides the smaller subset list of run-of-river projects FBC considered in its portfolio analysis. As FBC does not require all of these resource options in the future, it has provided earliest availability rather than in-service date.

Name	Service Territory	Nameplate Capacity (MW)	UEC ($/MWh)[14]	UCC ($/kW-year)[15]	Earliest Availability
RoR2	BC Hydro	10.7	$150	$1,695	2021
RoR3	BC Hydro	13.9	$132	$1,592	2021
RoR4	BC Hydro	16.8	$136	$1,743	2021
RoR5	BC Hydro	22.3	$131	$1,567	2021
RoR6	BC Hydro	28.6	$120	$1,674	2021
RoR7	BC Hydro	45.5	$110	$1,230	2021
RoR8	BC Hydro	52.7	$124	$1,611	2021
RoR9	BC Hydro	66.3	$115	$1,924	2021
RoR10	BC Hydro	73.4	$87	$1,586	2021

30.2 Please provide their locations on a map of BC.

Response:

Please refer to the response to CEC IR 1.29.2.

[14] Assumes a 6 percent discount rate.
[15] Assumes a 6 percent discount rate.

30.3 Please provide the expected size and costs for each project.

Response:

Please refer to the response to CEC IR 1.30.1.

31. Reference: Exhibit B-1, Appendix J, page 39

> As part of the resource options collaboration with BC Hydro, five potential utility-scale solar PV sites with 5 MW of installed capacity were identified in southern B.C. FBC narrowed this group down to the three lowest cost projects. The supply curve for these options is provided in the following figure.

31.1 Please provide the names of the three lower cost options without their specific identities and their expected in-service dates.

Response:

The following table shows the three solar projects considered in FBC's portfolio analysis. As FBC does not require all of these resource options for the preferred portfolio, it has provided earliest availability rather than in-service date.

Name	Service Territory	Nameplate Capacity (MW)	UEC ($/MWh)[16]	UCC ($/kW-year)[17]	Earliest Availability
Solar1	FBC	5	$169	$1,413	2020
Solar2	FBC	5	$184	$1,407	2020
Solar3	FBC	5	$181	$1,399	2020

31.2 Please provide locations on a map of BC.

Response:

Please refer to the response to CEC IR 1.29.2.

31.3 Please provide the expected size and costs for each project.

Response:

Please refer to the response to CEC IR 1.31.1.

[16] Assumes a 6 percent discount rate.
[17] Assumes a 6 percent discount rate.

32. Reference: Exhibit B-1, Volume 2 Long Term DSM Plan page 14

The following Table 3-1 shows key DSM scenario data, including the percentage of forecast load growth to be offset by DSM and the sum total of DSM savings to be targeted over the planning horizon. For context, of the total (2016 to 2035) annual savings, FBC has booked 511 GWh of DSM program savings from program inception in 1989 to 2015 inclusive.

Table 3-1: Key DSM Scenario Data

Category	DSM Scenario			
	Low	Base	High	Max
Annual Savings, GWh				
Average per annum ('18-'35)	20	26	31	36
% of load growth ('18-'35)	50%	66%	77%	89%
Total (2016 to 2035)	407	523	602	686
Resource Cost, 2016 $/MWh				
Incremental cost incl. program costs	$45	$88	$104	$114

32.1 Please provide total DSM program historical performance for each of the last ten years by rate class:

- Annual savings, GWh planned and actual
- Resource costs $/MWh planned and actual
- Customer participation planned and actual
- Please break out data from Kelowna

Response:

The requested information is not available by rate class, but is filed historically by major customer sector: Residential, Commercial, and Industrial. The data for annual savings and resource costs by customer sector is contained in the table below.

		Approved Annual Energy Savings	Actual Annual Energy Savings	Plan Levelized Cost[1]	Actual Levelized Cost
Year	Sector	(GWh)		($/MWh)	
2007	Residential	10.6	15.3	-	19
	Commercial	9.2	10.4	-	20
	Industrial	2.0	2.2	-	21
	Total	21.8	27.9	-	21
2008	Residential	8.4	12.9	-	26
	Commercial	9.1	11.0	-	20
	Industrial	2.0	3.3	-	30
	Total	19.5	27.3	-	22
2009	Residential	10.7	9.3	-	31
	Commercial	11.6	16.4	-	18
	Industrial	3.0	2.7	-	22
	Total	25.3	28.4	-	23
2010	Residential	12.1	11.6	-	28
	Commercial	12.1	14.7	-	20
	Industrial	3.4	3.0	-	19
	Total	27.5	29.3	-	23
2011	Residential	16.4	11.4	-	42
	Commercial	13.9	24.2	-	27
	Industrial	9.4	0.8	-	21
	Total	39.7	36.3	-	34
2012	Residential	16.1	12.8	-	64
	Commercial	13.4	17.9	-	37
	Industrial	2.5	0.9	-	45
	Total	32.0	31.6	-	51
2013	Residential	16.9	16.2	-	67
	Commercial	12.0	10.9	-	53
	Industrial	2.6	2.5	-	96
	Total	31.5	29.6	-	67
2014	Residential	5.8	8.7	16.0	52
	Commercial	6.2	5.3	17.0	57
	Industrial	0.8	0.6	12.4	78
	Total	12.8	14.6	21.0	55
2015	Residential	12.1	5.6	30.7	40
	Commercial	12.5	5.9	25.7	67
	Industrial	1.5	1.1	19.7	57
	Total	26.2	12.6	34.0	60
2016	Residential	12.9	12.5	30.7	75
	Commercial	12.7	8.1	25.7	81
	Industrial	1.6	2.1	19.7	16
	Total	27.2	22.8	34.0	51

[1] Levelized costs were not submitted on a plan basis prior to 2014.

As explained in response to BCSEA IR 1.10.2, FBC does not have metrics for the number of customers participating, nor can the Kelowna data be broken out.

Attachment 4.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)