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May 18, 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. 2

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. 2.

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

33. Reference: Exhibit B-9 Shadrack IR 17.i – 17ii

17. With reference to A3 BCUC IR #1.19 has FBC experienced any time, since 2010, an inability to purchase power on the spot market at any price?

Response:

Yes, on April 22, 2013 FBC attempted to secure market power for one hour in the morning, and could not at any cost.

i. On what dates and for what length of hours did this occur?

Response:

Please refer to the response to Shadrak IR1.17i.

ii. Did this situation result in power outages or forced shut down of certain customers' electricity supply? Please elaborate.

Response:

In this situation, FBC was attempting to purchase a relatively small volume of 10 MW in order to meet forecast demand plus a reasonable buffer, which is typically 15 to 30 MW, depending on the hour. Actual load for the hour was such that the 10 MW was not required to meet load, and therefore it did not cause an imbalance on the FBC system. Had it caused an imbalance, it would not have resulted in a forced shut down of any customer's electricity supply, as FBC has contractual methods of dealing with any imbalance transfer with BC Hydro.

33.1 There was only one hour in more than six years when FBC was unable to secure market power. That is a historical probability of less than 1/52560 or 0.000019. Does FBC expect that probability to increase or decrease over the next 10 years? Please explain why or why not and provide a discussion of the factors that are expected influence the availability of market power.

Response:

FBC does not have knowledge of all hours where the market would not have been available if FBC had attempted to secure power. As FBC is only rarely in the real time market to meet capacity needs, it is to be expected that the number of hours FBC was unable to obtain power is much lower than the number of hours power was not available. As discussed in Appendix L of the LTERP, and in the response to BCUC IR 1.19.1.1, FBC assumes the market will be

available 99.84 percent of the time, and that the transmission to the market will be available 99.45 percent of the time, which is lower than the probability calculated in the question, but based on an appropriate method for resource planning purposes. The two main factors that are expected to influence the availability of market power are regional transmission availability and the liquidity in the market.

33.1.1 If FBC expects that probability to change in the next ten years, please provide FBC's expected probability that it will be unable to access market power at any price.

Response:

Please refer to the response to CEC IR 2.33.1.

33.2 In answer to Shadrack 17ii, FBC states it has contractual methods with BC Hydro to deal with any imbalance transfer problem. Please provide an overview of the contracts with BC Hydro that mitigate the risk of imbalance transfer to BC Hydro, and identify any limitations within these contracts.

Response:

The contract FBC referred to in the response to Shadrack IR 1.17.ii is the Imbalance Agreement, which is not a contract that mitigates the risk of imbalance transfers, rather it is a contract that deals with actual imbalances.

FBC and BC Hydro entered into the Imbalance Agreement in 2013and it became effective July 1, 2014, as approved by Commission Order G-60-14.[1]

The Imbalance Agreement sets out the terms under which FBC will settle with BC Hydro for any inadvertent flows of electricity between the BC Hydro system and the Entitlement parties' system due to unexpected conditions or circumstances. FBC must use reasonable commercial measures to avoid any such imbalances and cannot rely on or plan on the use of imbalance energy as a resource for meeting its system requirements. As such, the payments FBC must

[1] http://www.bcuc.com/ApplicationView.aspx?ApplicationId=399

make to BC Hydro in the event of any imbalance are linked to market prices and are structured to act as a financial disincentive.

33.3 Please provide FBC's views as to the reliability of these contractual methods for dealing with imbalance transfer, and provide the hourly probability that in the next ten years that BC Hydro will be unable to provide power in the event FBC is unable to access market power.

Response:

FBC is unable to calculate the probability of failing to receive imbalance energy due to lack of supply on the BC Hydro system, but believes it be extremely low.

33.4 Please provide FBC's calculated joint probability that both of the following circumstances will occur in the same hour in the next ten years.

a) market power will be unavailable to FBC and

b) BC Hydro will be unable to provide power to deal with an imbalance transfer problem

Response:

Please refer to the response to CEC IR 2.33.3.

33.5 Please provide a similar calculation for the next twenty years.

Response:

Please refer to the response to CEC IR 2.33.3.

34. Reference: Exhibit B-9 Shadrack IR 9ii

Response:

As a result of the Canal Plant Agreement (CPA), the overall physical balancing of generation and load in BC is done by BC Hydro. Typically, BC Hydro does not use FBC's Kootenay River facilities as a balancing resource for the province. On an hourly basis, FBC must ensure it has resources in place to meet overall customer needs, which includes using the maximum amount of generating capability from the Kootenay River facilities derived from entitlement under the CPA, even though those units may not be generating at their maximum capability. If FBC does not have sufficient resources in place to meet overall customer power needs, unauthorized inadvertent power will flow from BC Hydro to FBC, and FBC must pay financial penalties to BC Hydro.

II. How does FBC currently adjust load production from its facilities on the Kootenay River, in accord with overall customer power needs?

34.1 Please define an average unauthorized inadvertent power flow over the last ten years.

Response:

Since the Imbalance Agreement became effective in July 2014, FBC has had inadvertent flows in 7 hours for a total of 94 MWh and $8,968. Prior to the Imbalance Agreement, the contractual arrangement with BC Hydro was different and therefore a comparable analysis cannot be completed.

34.2 Please detail the financial penalties FBC would have to pay to BC Hydro in the event of an unauthorized inadvertent power flow.

Response:

In the event of an inadvertent transfer of imbalance energy in any hour under the Imbalance Agreement, FBC will pay the greater of:

1) $1,000;
2) $50 per MWh; or
3) 150 percent of the hourly market rate.

34.2.1 Please provide context for the financial penalties in terms of the size of rate impact that would likely accrue as a result of unauthorized, inadvertent power flows.

Response:

As set out in the response to CEC IR 2.34.1, the charges under the Imbalance Agreement totaled $8,968 between July 2014 and April 2017, which has had no material impact on rates.

34.3 Please confirm that unauthorized inadvertent power flow would occur automatically and that electrical service to FBC customers would not be affected in any way.

Response:

Confirmed.

34.4 Is it the case that at any time that FBC does not have sufficient resources in place to meet overall customer power needs, anywhere on its system, that inadvertent power will flow from BC Hydro or other utilities on the interconnected grid to FBC? Please explain.

Response:

If FBC did not have sufficient resources in place to meet overall customer power needs, then inadvertent power would flow from BC Hydro under the terms of the Imbalance Agreement. Please also refer to the response to CEC IR 2.33.2.

34.5 Please confirm that the only consequence to FBC in the case described above is a financial penalty.

Response:

Confirmed.

34.6 If there are other consequences, please describe fully and provide quantification where applicable.

Response:

Please refer to the response to CEC IR 2.34.5.

35. Reference: Exhibit B-3, BCOAPO 1.25.2, BCUC Order E-10-15, Appendix A pages 3 and 11

> 25.2 Please explain why "additional firm transmission cannot be reliably obtained on the U.S. side of the border".
>
> **Response:**
>
> Additional firm transmission cannot be reliably obtained on the U.S. side of the border because all of the long-term firm transmission rights have been acquired. However, U.S. transmission can generally be obtained through short-term non-firm reservations, when it is available, which can be used to deliver firm energy. For the most part, FBC has been able to secure non-firm transmission when required, although there have been times when no transmission was available. At this time, FBC has been able to mitigate this risk by entering into the Capacity and Energy Purchase and Sale Agreement with Powerex, as Powerex is a significant holder of firm transmission capacity from the U.S. to the B.C./U.S. border.

> FBC describes the CEPSA as a master agreement in that it sets out the terms and conditions for future market transactions entered into by FBC with Powerex. Under the CEPSA, FBC will purchase all of its market energy requirements from Powerex and will sell any surplus capacity that may be available after meeting FBC's load requirements to Powerex. FBC states the benefits of this arrangement include increased certainty of energy access as well as surplus capacity sales at prices that are potentially better than could be achieved elsewhere, optimizing FBC's resource portfolio.[1]

> 3.1.3 The availability of supplies of the energy
>
> FBC submits that while the CEPSA is not required in order for FBC to have access to market supply, the CEPSA increases FBC's ability to purchase energy based on market prices and is therefore expected to increase the overall reliability of FBC purchases of energy to serve load.[18] FBC states that:
>
> > [T]ransmission from within the US to the border can be difficult at times to obtain and firm transmission rights are rarely available. Currently FBC's counterparties generally rely on the availability of non-firm transmission capacity to deliver to the border to serve FBC purchases.
> >
> > Under the Agreement, Powerex will be responsible for obtaining transmission capacity to deliver to the BC/US border to the degree it is necessary. FBC expects that Powerex will determine any transmission requirements to fulfill FBC's energy purchases as part of its market activities to support the optimisation of the BC Hydro system. As such it is expected that Powerex will be able to deliver energy purchases to the BC/US border or to the Kootenay Interconnection with a higher degree of certainty than FBC could achieve under its existing market arrangements, at comparable or lower cost.[19]

35.1 Please confirm the CEPSA is in place until 2018 and renewable annually thereafter until 2025.

Response:

Confirmed. The CEPSA can be renewed by mutual agreement on an annual basis until 2025.

35.1.1 If not confirmed, please provide the terms for the CEPSA and/or a copy of the agreement.

Response:

Please refer to the response to CEC IR 2.35.1.

35.2 Please confirm that FBC will purchase all of its market energy requirements from Powerex under the CEPSA.

Response:

Confirmed.

35.2.1 If not confirmed, please explain why not and clarify from where and how much energy FBC would be likely to purchase from alternative sources.

Response:

Please refer to the response to CEC IR 2.35.2.

35.3 Please explain why the CEPSA was not mentioned in the LTERP application, particularly in sections 2.4.4 Regional market Opportunities, 8.2.4 Market Purchases, and Appendix J section 3.5 Market Purchases.

Response:

The CEPSA is discussed in the LTERP in Section 1.4.2, Section 2.4.4, and Section 5.3. However, for greater clarity, more detail on the CEPSA is provided in this response.

The CEPSA is an operating agreement with Powerex that addresses how FBC currently accesses the market. It does not provide for anything related to market access that FBC would not have in the absence of the CEPSA, aside from providing a higher degree of certainty that market access will be available in the short to medium.

This increased certainty of market access is an operational benefit that has no direct impact on the LTERP or preferred portfolio. As discussed in the response to BCUC IR1.19.1, FBC assumes that transmission will be available in all hours, limited only by the assumed probability of a forced outage on Line 71, based on its historical availability. The CEPSA does not impact this assumption because the transmission benefits of the CEPSA are only available when Line 71 is available. Furthermore, the CEPSA can expire as early as September, 2018, but can be renewed annually by mutual agreement between FBC and Powerex through 2025. FBC does not have any certainty that the CEPSA will be in place at any time beyond September 2018.

35.4 Please provide FBC's best estimate to quantify the higher degree of certainty referred to in the order (reference above).

Response:

It is difficult to determine with what degree of certainty the CEPSA provides increased transmission reliability, as FBC cannot compare a scenario with the CEPSA to one without the CEPSA. In other words, it is unknown if the CEPSA would have been able to avoid previous transmission issues that have occurred. However, since the CEPSA became effective, FBC has not had any significant transmission issues when purchasing market power. Prior to the CEPSA, FBC has typically experienced transmission issues a few times a year, when trying to source low cost market energy as a result of transmission congestion, and/or last minute changes to transmission paths. Since these purchases were for energy only, and not for peak demand requirements, FBC was not harmed, and was able to bring in the required energy in a later hour or later date.

35.5 What is the probability that, under the CEPSA agreement, FBC will be unable to access market power when it is needed for the period until 2025?

Response:

Please refer to the responses to CEC IRs 2.35.3 and 2.35.4.

35.6 Under the CEPSA, is FBC able to access surplus power from BC Hydro in addition to or in place of PPA power? Please explain.

Response:

No, the CEPSA only provides FBC with access to the U.S. wholesale power market and does not provide FBC with any access to BC Hydro supply.

36. Reference: British Columbia Hydro and Power Authority ~ F2017 to F2019 Revenue Requirements Application ~ Project No. 3698869 Exhibit B-15 CEC IRs 2.135.3; 2.145 and British Columbia Hydro and Power Authority ~Exhibit B-17, 2016 Rate Design Application Evidentiary Update; BC Hydro ~F2017 to F2019 Revenue Requirements Application~ B-1-1 page 1320 of 1571 Appendix X Demand Side Management Assumptions page 2

2.135.3 Please provide the complete dataset for BC Hydro's surplus and deficit by year dating back to 1961, and include the value of market sales and market purchases for each year.

	1964	1965	---	---	2016	Total
Surplus (kwh)						
Market Sales (kWh)						
Market Sales $						
Deficit (kwh)						
Market Purchases (kwh)						
Market Purchases ($)						
Total Identify KWh						

RESPONSE:

The Transfer Price Agreement between BC Hydro and Powerex came into effect April 1, 2003, at the start of fiscal 2004. Prior to this date, electricity purchases and sales were not split between trade and domestic and as a result the information requested for before fiscal 2004 is not available. BC Hydro is providing the net annual surplus or deficit in a given fiscal year.

BC Hydro is not able to provide Total Identify (KWh) as part of this response, because we are not certain as to what the term refers to.

Fiscal Year	Energy Surplus.[1] (GWh)	Market Electricity Sale Energy (Surplus Sales) (GWh)	Market Electricity Sale Revenue (MCAD)	Energy Deficit[1] (GWh)	Market Electricity Purchase Energy (GWh)	Market Electricity Purchase Cost (MCAD)
2004		0	0.0	5200	5349	270.0
2005		0	0.0	4000	6896	393.2
2006		0	0.0	4000	5853	351.1
2007		0	0.0	9000	5698	249.7
2008	1600	811	31.9		2258	153.3
2009		196	9.7	3500	5020	272.6
2010		0	0.0	6400	2161	80.5
2011		53	0.1	4600	3791	128.4
2012	5600	710	12.7		840	18.6
2013	5700	6020	80.2		359	10.1
2014		1008	36.7	1700	918	41.9
2015	5500	15	0.2		207	6.0
2016	3300	6277	174.1		122	2.8

1

1.32.3 What would be the RRA impact of reducing the excess of energy during the test period?

RESPONSE:

The amount of consolidated net energy generated in excess of the load forecast is estimated at 4,945 GWh in fiscal 2017, 4,928 GWh in fiscal 2018 and 3,524 GWh in fiscal 2019. BC Hydro expects to optimize the value of this energy by selling this energy into neighboring electricity markets and the estimated sales revenue is reflected in the revenue requirement calculation in the Application.

2

Table 3 Energy LRB After Planned Resources

Operating Planning

(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Existing and Committed Heritage Resources		46,936	46,054	46,228	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671
Site-C									388	4,435	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100
Sub-total	(a)	46,936	46,054	46,228	48,671	48,671	48,671	48,671	49,059	53,106	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771
Existing and Committed IPP Resources	(b)	13,819	14,735	14,208	16,205	15,948	15,359	13,225	12,688	12,319	11,928	11,818	11,500	10,903	10,187	9,723	9,654	9,608	9,447
Future Supply-Side Resources																			
IPP Renewals		84	241	569	663	811	1,108	3,188	3,586	3,850	4,171	4,255	4,442	4,850	5,583	6,048	6,099	6,141	6,302
Standing Offer Program		75	168	279	369	500	611	721	832	943	1,053	1,184	1,275	1,385	1,496	1,607	1,717	1,828	1,939
North Coast Capacity Additions		0	0	0	0	0	154	154	154	154	154	154	154	154	154	154	154	154	154
Sub-total	(c)	159	409	848	1,072	1,311	1,873	4,043	4,572	4,947	5,378	5,573	5,871	6,389	7,233	7,808	7,970	8,123	8,395
Total Supply	(d) = a + b + c	61,012	61,198	61,284	65,948	65,930	65,903	65,940	66,320	70,372	71,077	71,162	71,142	71,123	71,192	71,302	71,396	71,503	71,613
Demand - Integrated System Total Gross Requirements																			
2015 Oct Mid Load Forecast Before DSM*		-60,231	-61,866	-63,832	-65,432	-66,676	-67,843	-68,850	-69,650	-70,420	-71,440	-72,288	-73,316	-74,277	-75,292	-76,381	-77,515	-78,441	-79,350
Expected LNG Load		-289	-355	-518	-2,020	-2,544	-2,570	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000
Sub-total	(e)	-60,520	-62,221	-64,350	-67,452	-69,220	-70,413	-71,850	-72,650	-73,420	-74,440	-75,288	-76,316	-77,277	-78,292	-79,381	-80,515	-81,441	-82,350
Demand Side Management & Other Measures																			
SMI Theft Reduction		193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193
Voltage and VAR Optimization		111	200	220	237	268	289	302	307	312	316	334	339	344	348	353	358	363	368
2016 DSM Plan F15 and F16 savings		1,343	1,399	1,367	1,335	1,357	1,393	1,391	1,401	1,397	1,242	1,107	1,108	1,072	1,021	1,003	1,018	1,016	1,008
2016 DSM Plan F2017+ savings		680	1,280	1,785	2,448	2,958	3,415	3,814	4,153	4,423	4,853	5,203	5,399	5,626	5,869	6,082	6,178	6,095	6,077
Sub-total	(f)	2,328	3,072	3,564	4,212	4,786	5,279	5,701	6,054	6,325	6,604	6,837	7,039	7,235	7,431	7,632	7,746	7,667	7,643
		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Surplus / Deficit	(g) = d + e + f	2,819	2,048	498	2,709	1,496	769	(209)	(276)	3,277	3,241	2,711	1,866	1,082	331	(447)	(1,373)	(2,272)	(3,094)
Small Gap Surplus / Deficit		5,611	6,137	5,903	9,251	8,743	8,654	7,917	8,001	11,633	12,102	11,931	11,290	10,792	10,050	9,794	9,982	8,699	7,829
Large Gap Surplus / Deficit		(341)	(2,662)	(5,926)	(5,217)	(7,366)	(8,606)	(10,090)	(10,429)	(7,404)	(7,942)	(8,700)	(9,947)	(11,045)	(12,128)	(13,078)	(14,456)	(15,808)	(16,827)

Market price of electricity: used as an additional filter for the Utility Cost test
BC Hydro's forecast of market sell prices at the B.C.-U.S. border, updated with 2015 exchange rates, has a levelized value of approximately $36/MWh (F2016 $) over a 20-year period from F16 to F35.

36.1 Given that BC Hydro has been in a surplus energy position for 4 of the past 5 years, and is forecast to be in a surplus energy position for the next three years at least, and possibly up to 20 years or longer with the first Site C energy expected to come on line as planned in December 2023[2], please advise what efforts FBC has made to engage with BC Hydro to secure long term access to this clean electricity.

Response:

FBC has renewed the PPA with BC Hydro, thereby securing access at embedded cost rates through the term of the PPA ending in 2033. The extent of BC Hydro's obligation under the PPA is 200 MW and all associated energy, or 1752 GWh. Of this amount, 1041 GWh is at Tranche 1 rates with the balance at Tranche 2. Increasing these amounts under the PPA would require reopening negotiations with BCH. While it is unlikely that the current terms of the PPA could simply be scaled up, it is possible that a new agreement could be reached with BC Hydro that could potentially be a cost-effective resource option under all portfolios. Given that FBC has no need of additional resources at this time, such negotiations are premature. FBC expects that an option to increase BC Hydro supply may be appropriate to consider in the next LTERP.

Please also refer to the response to BCUC IR 1.30.2.

[2] BC Hydro, Site C Clean Energy Project Quarterly progress Report No. 5 https://www.sitecproject.com/sites/default/files/quarterly-progress-report-no5-f2017-q2-july-september-2016.pdf

36.2 Please describe what options FBC may have to access to this surplus energy, besides the existing PPA.

Response:

FBC could access BC Hydro surplus power either directly through a second, new contract, or through a market based arrangement with Powerex. Any arrangement with Powerex would be supplied in whole or in part with BC Hydro surplus as Powerex manages its overall portfolio.

36.3 Has FBC considered the possibility of meeting all of its energy and capacity needs over the LTERP period with surplus power from BC Hydro?

Response:

FBC has not considered the possibility of meeting all of its energy and capacity needs over the LTERP with surplus power from BC Hydro as part of this LTERP. Please refer to the responses to CEC IRs 2.36.1 and 2.36.2.

36.3.1 If yes, please provide FBC's views as to the possibility of meeting its energy and capacity needs with surplus power from BC Hydro.

Response:

Please refer to the response to CEC IR 2.36.3.

36.3.2 If no, please explain why not.

Response:

Please refer to the response to CEC IR 2.36.1.

36.4 Please provide BC Hydro's most recent Load Resource Balance.

Response:

FBC's understanding is that BC Hydro's most recent published Energy Load Resource Balance can be found in Table 3.6 of its Fiscal 2017 to Fiscal 2019 Revenue Requirements Application[3], and is provided below.

[3] Exhibit B-1-1, British Columbia Hydro and Power Authority ~ F2017 to F2019 Revenue Requirements Application, Chapter 3, Table 3-6, page 3-29.

1

Table 3-6 Energy Load Resource Balance with Existing and Committed Resources

(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																					
Heritage Resources (including Site C)	(a)	48,445	46,895	46,014	48,491	48,491	48,491	48,491	48,857	52,383	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777
Existing and Committed IPP Resources	(b)	13,252	14,681	14,457	14,456	14,188	13,874	13,639	13,302	12,906	12,506	12,399	12,075	11,559	10,811	10,351	10,295	10,255	10,106	9,568	8,201
Total Supply (Operating View)**	(c) = a + b	61,697	61,576	60,471	62,947	62,680	62,366	62,130	62,159	65,289	66,283	66,176	65,853	65,336	64,589	64,129	64,073	64,033	63,884	63,345	61,979
Demand - Integrated System Total Gross Requirements																					
2016 May Mid Load Forecast Before DSM*		-58,334	-59,013	-60,413	-61,371	-62,309	-63,675	-64,836	-66,008	-67,109	-68,310	-69,267	-70,256	-71,222	-72,296	-73,374	-74,535	-75,462	-76,393	-77,215	-78,089
Expected LNG Load		-61	-148	-148	-252	-1,265	-2,299	-2,721	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848
Sub-total	(d)	-58,395	-59,162	-60,561	-61,624	-63,574	-65,974	-67,557	-68,856	-69,957	-71,158	-72,115	-73,104	-74,070	-75,144	-76,222	-77,383	-78,310	-79,241	-80,063	-80,937
Existing and Committed Demand Side Management & Others Measures																					
SMI Theft Reduction		83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Voltage and VAR Optimization		67	152	171	188	219	240	254	259	263	268	285	290	295	300	305	310	315	320	325	331
2016 DSM Plan F16 savings		982	970	939	940	935	926	923	917	912	885	863	855	848	844	807	770	760	758	757	736
Sub-total	(e)	1,131	1,204	1,193	1,211	1,237	1,249	1,260	1,258	1,258	1,235	1,231	1,228	1,226	1,227	1,195	1,163	1,157	1,161	1,165	1,150
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus/(Deficit) (Operational View) **	(f) = c + d + e	**4,433**	**3,619**	**1,102**	**2,535**	**343**	**(2,359)**	**(4,167)**	**(5,439)**	**(3,410)**	**(3,640)**	**(4,708)**	**(6,023)**	**(7,508)**	**(9,328)**	**(10,898)**	**(12,148)**	**(13,120)**	**(14,197)**	**(15,553)**	**(17,808)**
Surplus / Deficit as % of Net Load (Planning View) **		**107%**	**106%**	**103%**	**108%**	**104%**	**99%**	**94%**	**92%**	**95%**	**95%**	**93%**	**91%**	**89%**	**87%**	**85%**	**84%**	**83%**	**82%**	**80%**	**78%**
Low Load Forecast Surplus/(Deficit) (Operational View) **		6,754	6,179	4,115	5,925	4,210	2,026	598	(400)	1,931	1,995	1,137	68	(1,156)	(2,710)	(4,054)	(4,965)	(5,680)	(6,578)	(7,881)	(10,007)
High Load Forecast Surplus/(Deficit) (Operational View) **		2,046	727	(2,492)	(1,870)	(4,669)	(8,111)	(10,807)	(12,442)	(10,787)	(11,403)	(12,634)	(14,277)	(16,143)	(18,433)	(20,276)	(21,819)	(23,058)	(24,417)	(26,190)	(28,795)

* 2016 Integrated System Load Forecast with losses
** See section 3.4.2 for description of Operational versus Planning View

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36.5 Please comment on the likelihood that, when BC Hydro is in surplus, their cost value of energy will be in the range of market energy price.

Response:

FBC is not aware of any correlation between the cost of BC Hydro energy while it is in surplus and market energy prices.

36.6 Please provide BC Hydro's forecast of market energy prices for the next 20 years.

Response:

The response to a similar question was provided in the BC Hydro F2017-F2019 Revenue Requirements Application, Response to BCUC IR 2.310.01 (Exhibit B-14), the excerpt of which follows.

Calendar Year	Mid-Columbia Market Prices in 2016 USD/MWh (Refer to page B-6 of Appendix B of the ABB Report)	Apply USD/CAD FX Rate (U.S. $ per $1 CAD)	Mid-Columbia Prices Converted to 2016 CAD/MWh	Apply (Subtract) Wheeling/loss Adjuster ($/MWh)	Sell price at the B.C. Border in 2016 CAD/MWh	FY[1]	Sell Price at the B.C. Border in 2016 CAD/MWh – Fiscal Year Values
	Average		Average		Average		Average
2016	19.5	0.74	26.5	6.3	20.2	F17	21.4
2017	23.2	0.78	31.4	6.3	25.1	F18	25.0
2018	24.1	0.8	31.0	6.3	24.7	F19	25.5
2019	27.2	0.82	33.9	6.3	27.7	F20	28.4
2020	30.2	0.82	36.8	6.3	30.5	F21	31.3
2021	32.5	0.82	39.7	6.3	33.4	F22	33.7
2022	33.7	0.82	41.1	6.3	34.8	F23	35.2
2023	35.0	0.82	42.7	6.3	36.4	F24	36.5
2024	35.4	0.82	43.2	6.3	36.9	F25	37.1
2025	36.2	0.82	44.1	6.3	37.8	F26	38.1
2026	37.2	0.82	45.3	6.3	39.0	F27	39.3
2027	38.1	0.82	46.4	6.3	40.1	F28	40.3
2028	38.6	0.82	47.0	6.3	40.7	F29	41.2
2029	39.9	0.82	48.7	6.3	42.4	F30	42.9
2030	41.4	0.82	50.5	6.3	44.3	F31	44.7
2031	43.0	0.82	52.5	6.3	46.2	F32	46.4
2032	43.8	0.82	53.4	6.3	47.1	F33	47.4
2033	44.7	0.82	54.5	6.3	48.2		
			Average for the period F2017 to F2033				$36/MWh

36.7 Please confirm that Mid C electricity prices are sensitive to natural gas prices, as one of the determinants of price. Please discuss other factors impacting future electricity prices.

Response:

Confirmed, Mid-C electricity prices are sensitive to natural gas prices, which is one of the determinants of price.

Please also refer to the response to CEC IR 1.19.4 which discusses factors affecting uncertainty in the electricity market.

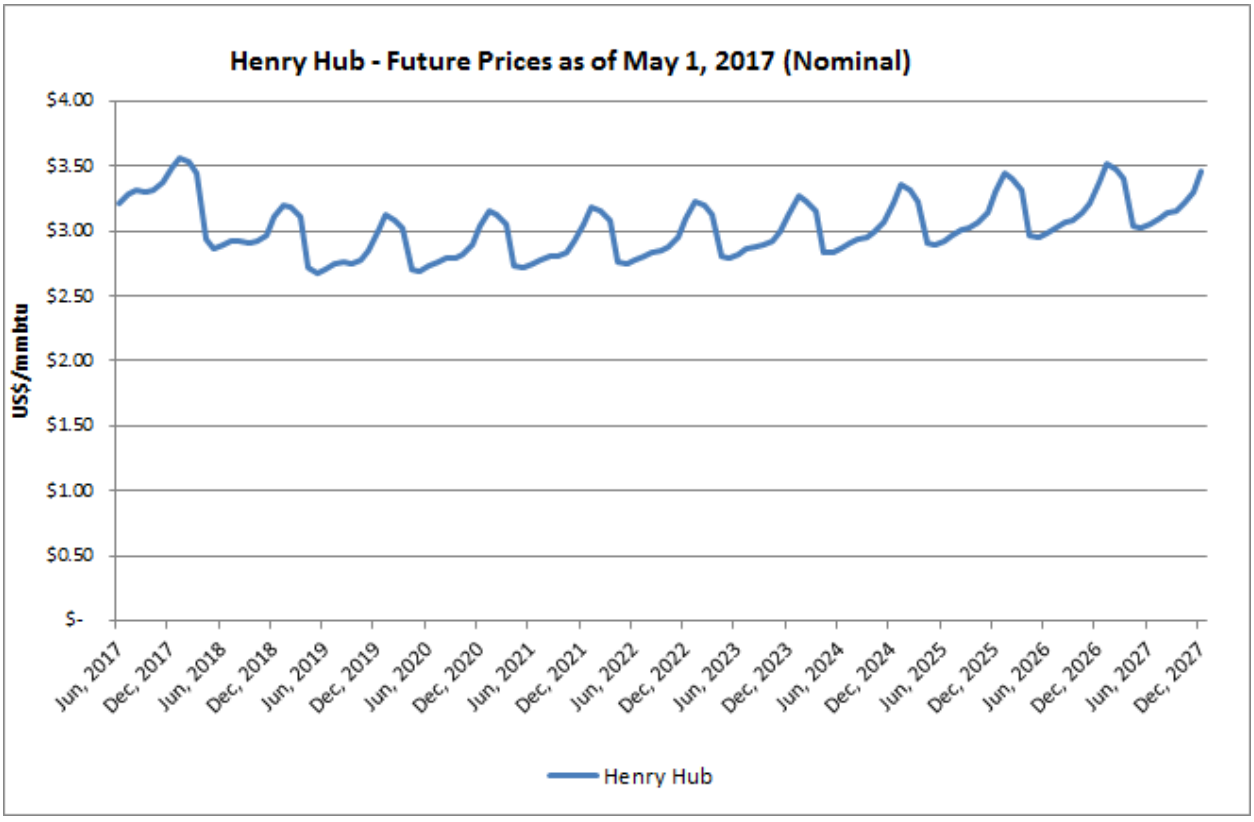
36.8 Please provide the data and graphic for CME futures prices for natural gas at Henry Hub for the next 10 years.

Response:

The following shows CME futures price settlements in US dollars per million British thermal units (US$/mmbtu), as of May 1, 2017, for natural gas at Henry Hub for the next 10 years.

Henry Hub - Future Prices (US$/mmbtu) as of May 1, 2017 (Nominal)

Date	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017						$3.22	$3.29	$3.32	$3.30	$3.31	$3.37	$3.50
2018	$3.57	$3.53	$3.45	$2.93	$2.87	$2.90	$2.92	$2.93	$2.90	$2.92	$2.97	$3.11
2019	$3.20	$3.18	$3.11	$2.72	$2.68	$2.71	$2.74	$2.76	$2.75	$2.78	$2.86	$3.00
2020	$3.12	$3.09	$3.03	$2.71	$2.70	$2.73	$2.76	$2.79	$2.79	$2.82	$2.89	$3.04
2021	$3.16	$3.12	$3.06	$2.74	$2.73	$2.75	$2.78	$2.81	$2.81	$2.84	$2.92	$3.06
2022	$3.19	$3.15	$3.08	$2.76	$2.75	$2.78	$2.81	$2.84	$2.85	$2.87	$2.95	$3.09
2023	$3.23	$3.19	$3.12	$2.81	$2.80	$2.83	$2.86	$2.89	$2.89	$2.92	$2.99	$3.14
2024	$3.28	$3.23	$3.16	$2.84	$2.83	$2.86	$2.91	$2.95	$2.96	$3.00	$3.07	$3.22
2025	$3.36	$3.31	$3.23	$2.91	$2.89	$2.93	$2.97	$3.01	$3.02	$3.07	$3.15	$3.30
2026	$3.44	$3.40	$3.32	$2.96	$2.95	$2.98	$3.03	$3.07	$3.08	$3.14	$3.22	$3.38
2027	$3.52	$3.48	$3.40	$3.04	$3.02	$3.06	$3.10	$3.14	$3.16	$3.21	$3.30	$3.46



37. Reference: Exhibit B-5, CEC IR 5.1; 5.2

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.

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

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%

1

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

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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.

1

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%

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3 37.1 Please indicate whether or not the above actuals data are weather normalized
4 and if not, please supply weather normalized data.
5

Response:

Weather normalized values are provided in Table 1 and Table 2 below. FBC acknowledges a correction to the Wholesale value of 663 GWh in the 1986 actual data in the response to CEC IR 1.5.1, which should have been 633 GWh.

Table 1: FBC Normalized Load

Year	Residential	Commercial	Wholesale	Kelowna	Industrial	Lighting	Irrigation	Net Load	Losses	Gross Load
1986	N/A	N/A	N/A		N/A	N/A	N/A	2,126	263	2,389
1987	726	300	663		360	13	44	2,106	277	2,383
1988	760	320	702		417	13	45	2,257	281	2,538
1989	779	338	717		455	13	40	2,341	294	2,635
1990	813	352	740		459	14	34	2,412	324	2,736
1991	863	364	763		433	13	41	2,477	312	2,789
1992	872	374	772		426	13	45	2,502	308	2,810
1993	926	411	805		491	12	33	2,678	340	3,018
1994	916	399	822		368	12	44	2,561	411	2,972
1995	966	430	844		327	12	46	2,625	367	2,992
1996	1,064	472	907		313	12	42	2,809	357	3,166
1997	924	456	835		289	12	36	2,552	340	2,892
1998	940	483	844		263	12	48	2,589	304	2,893
1999	940	485	837		273	12	45	2,593	316	2,909
2000	972	512	847		290	12	43	2,677	310	2,987
2001	1,013	520	857	278	335	10	43	3,057	245	3,301
2002	1,028	524	892	291	363	10	54	3,163	336	3,499
2003	1,025	520	887	293	337	10	52	3,123	347	3,470
2004	1,029	539	909	300	348	10	42	3,178	355	3,533
2005	1,040	568	922	301	357	12	44	3,244	378	3,622
2006	1,064	616	939	314	348	13	43	3,338	364	3,702
2007	1,165	650	979	291	314	13	48	3,461	346	3,806
2008	1,196	661	878	314	218	13	46	3,326	313	3,639
2009	1,239	675	908	331	216	13	49	3,431	321	3,752
2010	1,242	660	908	309	234	14	40	3,407	280	3,687
2011	1,249	657	895	329	271	13	40	3,455	308	3,763
2012	1,229	681	910	331	291	13	38	3,492	271	3,762
2013	1,353	788	899	321	352	13	40	3,767	277	4,044
2014	1,297	866	675		381	16	40	3,274	271	3,546
2015	1,298	853	567		380	16	46	3,160	268	3,428

Table 2: FBC Normalized Growth Rates (%)

Year	Residential	Commercial	Wholesale	Kelowna	Industrial	Lighting	Irrigation	Net Load	Losses	Gross Load
1987	N/A	N/A	N/A		N/A	N/A	N/A	-0.4%	5.3%	0.2%
1988	4.7%	6.7%	5.9%		15.8%	0.0%	2.3%	7.2%	1.4%	6.5%
1989	2.5%	5.4%	2.0%		9.1%	0.0%	-11.1%	3.7%	4.6%	3.8%
1990	4.4%	4.3%	3.3%		0.9%	7.7%	-15.0%	3.0%	10.2%	3.8%
1991	6.2%	3.4%	3.1%		-5.7%	-7.1%	20.6%	2.7%	-3.7%	1.9%
1992	1.0%	2.7%	1.2%		-1.6%	0.0%	9.8%	1.0%	-1.3%	0.8%
1993	6.2%	9.9%	4.2%		15.3%	-7.7%	-26.7%	7.0%	10.4%	7.4%
1994	-1.1%	-2.9%	2.1%		-25.1%	0.0%	33.3%	-4.4%	20.9%	-1.5%
1995	5.5%	7.8%	2.7%		-11.1%	0.0%	4.5%	2.5%	-10.7%	0.7%
1996	10.1%	9.7%	7.4%		-4.3%	0.0%	-8.7%	7.0%	-2.7%	5.8%
1997	-13.2%	-3.2%	-8.0%		-7.6%	0.9%	-14.3%	-9.1%	-4.8%	-8.6%
1998	1.7%	5.8%	1.1%		-9.2%	0.0%	33.3%	1.4%	-10.6%	0.0%
1999	0.1%	0.4%	-0.7%		4.0%	-0.9%	-6.3%	0.2%	3.9%	0.6%
2000	3.4%	5.6%	1.2%		6.1%	0.0%	-4.4%	3.2%	-1.9%	2.7%
2001	4.2%	1.6%	1.1%		15.7%	-16.1%	0.0%	14.2%	-21.1%	10.5%
2002	1.4%	0.8%	4.0%	4.7%	8.2%	1.7%	26.1%	3.5%	37.4%	6.0%
2003	-0.3%	-0.8%	-0.6%	0.5%	-7.3%	-0.4%	-4.5%	-1.2%	3.3%	-0.8%
2004	0.4%	3.7%	2.6%	2.4%	3.3%	0.3%	-18.0%	1.8%	2.3%	1.8%
2005	1.0%	5.3%	1.4%	0.5%	2.7%	17.4%	3.6%	2.1%	6.5%	2.5%
2006	2.4%	8.5%	1.8%	4.3%	-2.4%	4.9%	-2.4%	2.9%	-3.8%	2.2%
2007	9.5%	5.4%	4.3%	-7.3%	-9.8%	1.9%	12.7%	3.7%	-5.0%	2.8%
2008	2.6%	1.7%	-10.3%	7.8%	-30.6%	4.5%	-4.4%	-3.9%	-9.4%	-4.4%
2009	3.6%	2.2%	3.4%	5.2%	-1.0%	-0.8%	5.9%	3.2%	2.5%	3.1%
2010	0.2%	-2.3%	0.0%	-6.5%	8.3%	8.9%	-17.5%	-0.7%	-12.8%	-1.7%
2011	0.6%	-0.4%	-1.4%	6.5%	15.9%	-8.6%	-0.1%	1.4%	10.0%	2.1%
2012	-1.6%	3.6%	1.6%	0.4%	7.4%	1.9%	-5.8%	1.1%	-12.1%	0.0%
2013	10.1%	15.8%	-1.2%	-2.9%	21.2%	-0.1%	4.4%	7.9%	2.5%	7.5%
2014	-4.1%	9.8%	-24.9%		8.1%	16.0%	0.8%	-13.1%	-2.2%	-12.3%
2015	0.1%	-1.5%	-16.0%		-0.3%	1.6%	14.9%	-3.5%	-1.3%	-3.3%

37.2 Please confirm that Demand Side Management savings were not forecast in the 1995 Integrated Resource Plan, nor the 2005 Resource Plan and that this is the reason why these forecasts are not available prior to 2010.

Response:

FBC has not been able to locate the DSM forecasts by customer class from the 1995 Integrated Resource Plan because of the time elapsed, or for the 2005 Resource Plan, which was provided by a consultant. FBC has been able to locate the aggregate DSM forecasts, which have been incorporated in the Gross Load forecast in the tables below.

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

Table 1: Forecasts After-DSM (GWh)

Year	Res	Comm	Ind	Whsle	Lighting	Irrigation	Net	Losses	Gross	
1995	NA	NA	NA	NA	NA	NA	NA	NA	2,928	
1996	NA	NA	NA	NA	NA	NA	NA	NA	2,995	
1997	NA	NA	NA	NA	NA	NA	NA	NA	3,067	
1998	NA	NA	NA	NA	NA	NA	NA	NA	3,141	
1999	NA	NA	NA	NA	NA	NA	NA	NA	3,219	
2000	NA	NA	NA	NA	NA	NA	NA	NA	3,299	
2001	NA	NA	NA	NA	NA	NA	NA	NA	3,382	
2002	NA	NA	NA	NA	NA	NA	NA	NA	3,465	
2003	NA	NA	NA	NA	NA	NA	NA	NA	3,552	
2004	NA	NA	NA	NA	NA	NA	NA	NA	3,641	
2005	NA	NA	NA	NA	NA	NA	NA	NA	3,302	
2006	NA	NA	NA	NA	NA	NA	NA	NA	3,338	
2007	NA	NA	NA	NA	NA	NA	NA	NA	3,368	
2008	NA	NA	NA	NA	NA	NA	NA	NA	3,385	
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

Table 2: Forecast Growth Rates After-DSM

Year	Res	Comm	Ind	Whsle	Lighting	Irrigation	Net	Losses	Gross	
1995	NA	NA	NA	NA	NA	NA	NA	NA	N/A	
1996	NA	NA	NA	NA	NA	NA	NA	NA	2.3%	
1997	NA	NA	NA	NA	NA	NA	NA	NA	2.4%	
1998	NA	NA	NA	NA	NA	NA	NA	NA	2.4%	
1999	NA	NA	NA	NA	NA	NA	NA	NA	2.5%	
2000	NA	NA	NA	NA	NA	NA	NA	NA	2.5%	
2001	NA	NA	NA	NA	NA	NA	NA	NA	2.5%	
2002	NA	NA	NA	NA	NA	NA	NA	NA	2.5%	
2003	NA	NA	NA	NA	NA	NA	NA	NA	2.5%	
2004	NA	NA	NA	NA	NA	NA	NA	NA	2.5%	
2005	NA	NA	NA	NA	NA	NA	NA	NA	-9.3%	
2006	NA	NA	NA	NA	NA	NA	NA	NA	1.1%	
2007	NA	NA	NA	NA	NA	NA	NA	NA	0.9%	
2008	NA	NA	NA	NA	NA	NA	NA	NA	0.5%	
2009	NA	NA	NA	NA	NA	NA	NA	NA	0.5%	
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%

37.2.1 If not confirmed, please explain why the Forecasts and Forecast Growth Rates after DSM are not available before 2010.

Response:

Please refer to the response to CEC IR 2.37.2.

37.3 A comparison of the data for the period 2006 – 2015 shows that changes in gross load over this 10 year period were negative (-1%) and total increases in Net load were relatively small (2.5%). In contrast forecast load growth over the same period (Using before DSM figures for 2006 and 2007, and after DSM

figures for the period between 2008 and 2015) is 7%. Please provide FBC's views as to ratepayer impacts of this over-forecasting.

Response:

The forecast data provided in response to CEC IR 1.5.1 and repeated in the preamble to this question is from prior long term forecasts. The long term forecast is not used for rate setting (FBC forecasts load and supply annually for rate-setting purposes), so there are no cumulative ratepayer impacts due to variances in the long term load forecast. Please also see the response to CEC IR 2.37.5

37.3.1 Please quantify the ratepayer impacts over this period.

Response:

Please refer to the response to CEC IR 2.37.3.

37.4 Please quantify the impact of a 1% annual over-forecast over a 20 year period.

Response:

The impact of a "1% annual over-forecast over a 20 year period" is understood to be the impact on the Gross Load Forecast if the annual Gross Load growth rate is 1 percent less than forecast in each year of the planning horizon. Please refer to Table 1 below for the adjusted forecasts that reflect this scenario.

As noted in the response to CEC IR 2.37.3 there are no ratepayer impacts arising from variances in the long term load forecasts.

Table 1: Gross Load Forecast with a -1% annual growth rate adjustment

Year	Gross Load Forecast[4] (GWh)	Annual Growth Rate [A]	-1.0% Adjustment to Annual Growth Rate [A] – 1%	Adjusted Gross Load Forecast
2016	3,544.4			3,544.4
2017	3,595.2	1.4%	0.4%	3,559.8
2018	3,633.3	1.1%	0.1%	3,561.9
2019	3,675.7	1.2%	0.2%	3,567.9
2020	3,714.8	1.1%	0.1%	3,570.1
2021	3,750.2	1.0%	0.0%	3,568.5
2022	3,793.6	1.2%	0.2%	3,574.0
2023	3,839.2	1.2%	0.2%	3,581.2
2024	3,880.1	1.1%	0.1%	3,583.6
2025	3,922.3	1.1%	0.1%	3,586.8
2026	3,964.7	1.1%	0.1%	3,589.6
2027	4,005.2	1.0%	0.0%	3,590.4
2028	4,046.4	1.0%	0.0%	3,591.5
2029	4,088.0	1.0%	0.0%	3,592.4
2030	4,125.9	0.9%	-0.1%	3,589.8
2031	4,165.6	1.0%	0.0%	3,588.5
2032	4,207.3	1.0%	0.0%	3,588.5
2033	4,249.6	1.0%	0.0%	3,588.7
2034	4,291.6	1.0%	0.0%	3,588.3
2035	4,334.0	1.0%	0.0%	3,587.9

37.5 Please confirm that consistent over-forecasting could be reasonably expected to lead to an over-acquisition of supply for a period of time.

[4] 2016 LTERP. Appendix F – Load Forecast Tables. Section 2.1 Gross Load

Response:

Resources are planned to meet forecast load requirements. Therefore, if actual load requirements are consistently less than forecast on an annual basis over the planning horizon, it is possible that an over acquisition of supply may occur for a period of time. The flexibility of the PPA allows FBC some latitude to adjust supply side resources to align with lower than forecast load requirements if required. In addition, load forecasts are trued up to actual each time a new load forecast is developed. Therefore, the exposure to "consistent" over forecasting would be limited to each individual load forecast and there would be no cumulative effect of prior over-forecasts.

37.5.1 If not confirmed, please explain why not

Response:

Please refer to the response to CEC IR 2.37.5.

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37.6 Please confirm that consistent over-forecasting can result in an under-collection of revenues from customers, and lower than necessary rates for a period of time.

Response:

In the absence of flow-through treatment, over-forecasting in the load forecast used to set rates (not the long-term load forecast) could result in an over- or under-collection of revenue from customers, depending on whether marginal customer revenue is greater or lower than the marginal cost of power supply. At this time, FBC's marginal revenue generally exceeds marginal cost. When set rates are applied to a lower than forecast load, the reduction in revenue would exceed the avoided cost of supply, potentially resulting in a net under-recovery.

As explained in the response to CEC IR 2.37.3.1, both revenue and power purchase expense are flowed through in the subsequent year's revenue requirements, and customers are made whole for any forecast variances.

37.6.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 2.37.6.

37.7 Please confirm that price increases can reasonably be expected to result, to some extent, in reduced demand.

Response:

Confirmed that there is a correlation between price increases and reduced demand; FBC assumes a price elasticity of -0.05 percent.

37.7.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 2.37.7.

37.7.2 Please provide FBC's estimate of price elasticity for each rate class.

Response:

FBC uses a price elasticity estimate of -0.05, which is consistent with BC Hydro's estimate of price elasticity[5]. Based on the assessment of similarities between the two utilities, FBC believes that the BC Hydro estimate provides a good proxy for the price elasticity-driven savings for

[5] BC Hydro is considered as the closest utility to FBC in terms of its public policies, geographical proximity, customer mix and behavior, and its assumed price elasticity of -0.05 was presented in BCH 2012 IRP, App. 2A

FBC. This price elasticity, when coupled with a rough estimate of a real rate increase of 1.72 percent, produces a saving of approximately 0.086 percent of the load.

FBC assumes the price elasticity is consistent between rate classes, as is assumed by BC Hydro[6].

[6] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2012-electric-load-forecast-report.pdf

38. Reference: The CEC wishes to understand the historical relationship between FBC's forecasting and the Actual Total Gross Requirements. To the extent that the above information does not represent FBC's complete dataset of forecasts, please provide the full dataset of the FBC annual 10 year forecasts for each year starting in 1986 through 2017, after DSM, and the Actual as shown in the example table below.

	Forecast year	1986 GWh	1987 GWh	…. GWh	…. GWh	…. GWh	2035 GWh
Forecast vintage							
1986							
1987							
….							
2017							
Actual total gross requirement							

Response:

The data referenced in the preamble does represent the complete FBC dataset. FBC does not file long-term forecasts on an annual basis and is therefore unable to provide any additional data.

39. Reference: British Columbia Hydro and Power Authority ~ F2017 to F2019 Revenue Requirements Application ~ Project No. 3698869 Exhibit B-15, CEC IR 2.140.2

2.140.2 If BC Hydro is over-forecasting it would be reasonable to expect that this could create over-acquisition of supply and a greater cost to ratepayers than may be needed. Please discuss.

RESPONSE:

If BC Hydro was over-forecasting its energy needs, then during a specific test period the forecasted Cost of Energy may be greater than what will actually be used. However, BC Hydro's energy deferral accounts ensure that only the actual costs of energy are ultimately recovered in rates from our customers, as any excess of forecasted energy costs over actual energy costs would be a credit to the energy deferral accounts.

39.1 Does FBC maintain deferral account(s) to capture any excess of forecasted energy costs over actual energy costs? If yes, please identify and provide the historical balance over the last 20 years.

Response:

FBC has historically flowed through variances (not restricted to those situations where forecasts are higher than actuals) in certain components of power purchase expense. For example, expense variances related to the BPPA were recorded in accounts payable and flowed through to Power Purchase expense in the following year, and BC Hydro rate increases, which often are not known at the time of revenue requirements applications, have been flowed through to customers by way of a mid-year rate adjustment. Beginning in 2012, the total variance between forecast and actual power purchase expense has been captured in a deferral account and subject to 100 percent flow-through treatment.

To the extent that Power Purchase Expense variances are adjusted, it is necessary to match this treatment by also flowing through variances in sales revenue, the majority of which are attributable to weather related load variances, customer usage rate variances and customer count load variances, as has been the case since 2012. The revenue and power purchase expense variances that were captured in deferral accounts and flowed back to customers are shown in the table below.

	Revenue			Power Purchase Expense			Net Variance (Before Tax)
Year	Forecast	Actual	Variance	Forecast	Actual	Variance	
			(000s)				
2012	$ 287,445	$ 282,943	$ (4,502)	$ 87,149	$ 75,999	$ (11,150)	$ 6,648
2013	310,531	308,532	(1,999)	91,942	83,052	(8,890)	6,891
2014	312,927	317,330	4,403	87,163	86,337	(826)	5,229
2015	334,531	323,375	(11,156)	117,837	110,707	(7,130)	(4,026)
2016	350,593	335,186	(15,407)	133,907	123,169	(10,738)	(4,669)

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40. Reference: Exhibit B-5, CEC IR 32.1

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.

40.1 Why did FBC did not submit levelized costs on a plan basis prior to 2014?

Response:

An internal change came into effect for the 2014 DSM plan filing and resulted in levelized costs being submitted on a plan basis thereafter.

40.2 Please provide any data FBC has on DSM plan costs (in $/MWh) that were not submitted in the above table

Response:

The table below provides the levelized costs inclusive of Portfolio Costs (Supporting Initiatives) which were not included in the response to CEC IR 1.32.1.

Planning and Evaluation costs in 2015 and 2016 have also been reallocated by sector, consistent with the treatment of prior years. FBC also notes an error in the response to CEC IR 1.32.1. The 2016 levelized costs for Residential, originally stated at $75 per MWh, should have been $29 per MWh ($31 per MWh in the table below, with the inclusion of Planning & Evaluation costs).

		Approved Annual Energy Savings	Actual Annual Energy Savings	Plan Levelized Cost	Actual Levelized Cost
Year	Sector	(GWh)		($/MWh)	
2006	Residential	9.6	10.9	-	28
	Commercial	9.2	9.7	-	18
	Industrial	1.6	2.5	-	15
	Portfolio				-
	Total	20.4	23.1	-	15
2007	Residential	10.6	15.3	-	19
	Commercial	9.2	10.4	-	20
	Industrial	2.0	2.2	-	21
	Portfolio				-
	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
	Portfolio				0.5
	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
	Portfolio				-
	Total	25.3	28.4	-	23
2010	Residential	12.1	11.6	-	28
	Commercial	12.1	14.7	-	20

		Approved Annual Energy Savings	Actual Annual Energy Savings	Plan Levelized Cost	Actual Levelized Cost
Year	Sector	(GWh)		($/MWh)	
	Industrial	3.4	3.0	-	19
	Portfolio				1
	Total	27.5	29.3	-	24
2011	Residential	16.4	11.4	-	42
	Commercial	13.9	24.2	-	27
	Industrial	9.4	0.8	-	21
	Portfolio				0.2
	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
	Portfolio				2
	Total	32.0	31.6	-	53
2013	Residential	16.9	16.2	-	67
	Commercial	12.0	10.9	-	53
	Industrial	2.6	2.5	-	96
	Portfolio				2
	Total	31.5	29.6	-	69
2014	Residential	5.8	8.7	16	52
	Commercial	6.2	5.3	17	57
	Industrial	0.8	0.6	12	78
	Portfolio				1
	Total	12.8	14.6	21	56
2015	Residential	12.1	5.6	31	42
	Commercial	12.5	5.9	26	69
	Industrial	1.5	1.1	20	57
	Portfolio				3
	Total	26.2	12.6	34	60
2016	Residential	12.9	12.5	31	31
	Commercial	12.7	8.1	26	82
	Industrial	1.6	2.1	20	16
	Portfolio				3
	Total	27.2	22.8	34	51

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40.3 For the three years for which planned costs were provided, cost per MWh has been significantly higher than planned; 2014 162% higher, 2015 76% higher and 2016 50% higher.

40.3.1 Why have the actual costs been so much higher than planned.

Response:

Three factors affect the comparisons between actual and plan levelized costs:

1. Actual levelized costs are based on the total resource costs, which include both utility costs and the customer portion of measure costs, whereas the plan levelized cost per MWh is based on utility resource costs only. This results in actual levelized costs being higher than plan, all other things being equal;

2. 2015 and 2016 Plan levelized costs are an average for both years included in the plan; and

3. The savings in the actual levelized costs are net of free-riders, whereas the savings in the plan levelized costs are not. This results in actual levelized costs being higher than plan, all other things being equal.

40.3.2 How will FBC ensure that the cost of future years' DSM programs will be as planned?

Response:

FBC actively manages its DSM programs to the approved DSM Plan expenditure amount and energy savings target, not to the plan levelized cost. Management includes reviewing monthly internal reporting to track program results (savings and expenditures) to-date and adjusting marketing strategy as needed.

Please refer to the response to CEC IR 2.40.3.1 for an explanation of how the levelized costs (plan and actual) are derived, and why they differ in the referenced table. Furthermore, the actual levelized costs reported will vary to some degree from the plan figures since they are an

outcome of the actual costs and savings incurred, the mix of program measures undertaken, free-rider rates, and other inputs.

40.4 For the last two years actual energy savings were significantly less than approved. How will FBC ensure that in future years planned and approved energy savings will be achieved by its DSM program?

Response:

Please refer to the response to CEC IR 2.40.3.2.

40.4.1 Why were the actual savings so much lower than planned?

Response:

There were a number of reasons for the performance of FBC's DSM programs in 2015. As explained in the 2015 DSM Annual Report, one of the significant factors was the stepped increase in planned DSM spending in 2015 compared to 2014 (an increase from $3 million to $7.3 million). Commission acceptance of the 2015-2016 DSM Plan was received on December 3, 2014, leaving insufficient lead time to take the necessary steps to increase DSM programming back to levels needed to achieve planned spending and savings targets by year-end 2015.

In 2016, savings increased 81 percent from 2015, reaching 27.2 GWh, or 84 percent of the approved DSM Plan. FBC is on track to meet its 2017 approved DSM Plan.

40.5 Has FBC done any analysis of DSM performance vs plan? If so, please provide any reports or analysis.

Response:

FBC files its annual DSM report, which discusses actual results compared to approved plan, at the end of the first quarter of the following year. The 2016 and earlier FBC year-end DSM reports are submitted to the BCUC and published on the Company's website[7].

[7] https://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/ElectricBCUCsubmissions/DemandSideManagement/Pages/DSM-Reports.aspx