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December 16, 2016

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Laurel Ross,
Acting Commission Secretary and Director

Dear Sirs/Mesdames:

Re: British Columbia Hydro and Power Authority ("BC Hydro") F2017 to F2019 Revenue Requirements Application, Project No. 3698869

We are counsel for the Commercial Energy Consumers Association of British Columbia ("CEC"). Attached please find the CEC's second set of Information Requests with respect to the above-noted matter.

Should you have any questions regarding the foregoing, please do not hesitate to contact the writer.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer
CPW/jlb
cc: CEC
cc: BC Hydro
cc: Registered Interveners

REQUESTOR NAME:	Commercial Energy Consumers Association of British Columbia (CEC)
IR ROUND NO:	#2
TO:	British Columbia Hydro and Power Authority (BC Hydro)
DATE:	December 16, 2016
PROJECT NO	3698869
APPLICATION NAME:	F2017 to F2019 Revenue Requirements Application

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129. Reference: Exhibit B-10, 1.8.3 and 1.8.5; Exhibit B-9, BCUC 1.57.1

1.8.3 Please provide the Budget for Site C and identify when it was established.

RESPONSE:

The budget for the Site C Clean Energy Project is $8.335 billion, plus an additional $440 million project reserve subject to provincial Treasury Board approval, for a total of $8.775 billion.

This budget was established at the Final Investment Decision in December 2014. Please refer to: https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power.

1.8.5 Does BC Hydro anticipate being under budget, on budget or over budget for Site C? Please explain

RESPONSE:

BC Hydro expects to complete the Site C Clean Energy Project on budget.

1.57.1 Please explain the reasons for the unfilled positions in the Capital Infrastructure Project Delivery business group in F2015 and F2016.

RESPONSE:

The primary reason for the unfilled positions is lower than planned FTEs for the Site C Clean Energy Project Key Business Unit. When the fiscal 2015 and fiscal 2016 FTE plan numbers were established, BC Hydro expected that the Site C Clean Energy Project would have reached the Implementation Phase earlier than it actually did. As a result, the FTEs' ramped up later than originally planned.

Going forward, the Site C Clean Energy Project is working toward filling the vacancies, so the variances are expected to be less for the test period. In some cases, recruiting processes are extended due to the need to find experienced, qualified resources and relocate them to site.

129.1. Is the Site C Clean Energy Project currently behind schedule?

129.1.1. If yes, please provide the approximate time frame that BC Hydro is behind, and identify and quantify any costs or benefits that may be associated with the delay.

130. Reference: Exhibit B-10, CEC 1.13.1 and 1.14.2 and https://www.biv.com/article/2016/12/bc-government-announces-aggressive-plan-electrify-/ and Exhibit B-9, BCUC 1.8.1

1.13.1 What is the City of Vancouver residential load? Please express in $ and GWh with each as a percentage of total residential load.

RESPONSE:

The information requested is provided in the table below.

	City of Vancouver		BC Hydro		City of Vancouver	
	Residential Sales		Total Residential Sales		Percentage of Total Residential	
	GWh	Revenue ($ million)	GWh	Revenue ($ million)	Sales (%)	Revenue (%)
F2015	1,759	174	17,047	1,631	10.3	10.6
F2016	1,765	185	17,331	1,754	10.2	10.6

Note 1: The residential sales for the City of Vancouver are based on BC Hydro's billing system.

RESPONSE:

We have not adjusted our May 2016 Load Forecast to reflect policies that have been identified in the City of Vancouver's Renewable City Strategy or the Province's Climate Leadership Plan. The Renewable City Strategy includes policy actions that increase the use and supply of renewable energy. To the extent this renewable supply is delivered in the form of electricity supplied by BC Hydro, we would anticipate an increase in overall electricity demand, all other things being equal. However, we have not yet quantified the potential impacts of these and other policies identified in the Renewable City Strategy.

As noted in BC Hydro's response to CEC IR 1.24.1, our recent assessment of Province's Climate Leadership Plan concluded there are sufficient resources to meet expected load commitments as well as initial load requirements in the Climate Leadership Plan.

The longer term implications of the Climate Leadership Plan as well as other initiatives such as the City of Vancouver's Renewable Energy Strategy will be addressed as part of our 2018 Integrated Resource Plan.

B.C. government announces aggressive plan to electrify B.C. natural gas fields.

1.8.1 Please reconcile the growth projected for the oil and gas sector and BC Hydro's relatively small LNG volume anticipated in the large industrial forecast within the test period.

RESPONSE:

The table below shows the volume of LNG load[1] over the test period relative to the large industrial oil and gas sales forecast[2].

Fiscal Year	LNG Sales (GWh)	Incremental Growth in LNG Sales (GWh)	Large Industrial Oil and Gas Sales (GWh)	Incremental Growth in Oil and Gas Sales (GWh)
F2017	57		1,639	
F2018	139	67	1,993	354
F2019	139	0	2,652	659

130.1. Please provide the City of Vancouver Commercial and Industrial loads in the same format as that provided for Residential in CEC 1.13.1.

130.2. Please confirm that other municipalities such as the City of Victoria are also adopting environmental strategies that could reasonably be expected to affect the electricity load.

130.3. Please confirm that BC Hydro will be implementing fuel switching electrification to achieve greenhouse gas reductions, and that it is currently in the process of being developed, and that implementation will begin sometime in the test period.

130.3.1. If not confirmed, please explain.

130.4. Please confirm that the average natural gas use is approximately 90 GJ per home.

130.5. Please provide the number of single family dwellings in the City of Vancouver.

130.6. Please provide the number of multi-family dwellings in the City of Vancouver.

130.7. Please confirm that electrification of space and water heating would be more expensive than the existing gas fired space and water heating, and provide quantification of the approximate difference.

130.7.1. Please provide the total load for those Municipalities that BC Hydro is aware of that are adopting strategies related to the reduction of natural gas or other policies that could influence the electricity load requirements. Please identify the load by municipality and provide in the same way as for the Vancouver load (include residential, commercial and industrial).

130.8. Please provide the same information regarding dwellings for the City of Victoria and other municipalities that are adopting strategies related to the reduction of natural gas.

130.9. Please confirm that the BC Provincial government has adopted a policy of electrification of natural gas fields that BC Hydro is looking at implementing.

130.9.1. If not confirmed, please explain why not.

130.10. Please explain if BC Hydro anticipates beginning to implement this electrification at any time during the test period.

130.11. Please confirm that the load for the electrification is incorporated in the incremental oil and gas sales as shown in BCUC 1.8.1.

130.11.1. If yes, please provide a range of uncertainty around the oil and gas sales and the incremental oil and gas sales shown in BCUC 1.8.1.

130.11.2. If not, please provide an estimate of the load that could be generated as a result of the Provincial government policy of electrification with a range of uncertainty.

131. Reference: Exhibit B-10, CEC 1.15.5

		A Housing Starts Robert Fairholm Economic Consultant Provincial Total			B Housing Starts CMHC Provincial Total			C Housing Starts CMHC Provincial Total	
	Calendar Year	March 2015 [1]		Calendar Year	First Quarter 2015[2]		Calendar Year	Fourth Quarter 2016[2]	Range
Actual	2005	34,665	Actual	2005	31,119	Actual	2005	31,119	
Actual	2006	36,439	Actual	2006	32,571	Actual	2006	32,571	
Actual	2007	39,193	Actual	2007	34,362	Actual	2007	34,362	
Actual	2008	34,320	Actual	2008	30,857	Actual	2008	30,857	
Actual	2009	16,076	Actual	2009	13,833	Actual	2009	13,833	
Actual	2010	26,478	Actual	2010	23,600	Actual	2010	23,600	
Actual	2011	26,396	Actual	2011	24,346	Actual	2011	24,346	
Actual	2012	27,465	Actual	2012	25,477	Actual	2012	25,477	
Actual	2013	27,053	Actual	2013	25,685	Actual	2013	25,685	
Actual	2014	28,356	Actual	2014	26,741	Actual	2014	26,741	
Forecast	2015	27,566	Forecast	2015	28,300	Actual	2015	29,914	
Forecast	2016	27,434	Forecast	2016	29,000	Forecast	2016	39,300	37,700
Forecast	2017	26,798				Forecast	2017	34,400	32,000
Forecast	2018	26,751				Forecast	2018	32,000	29,700

Notes:

1. The source of actual data provided in column A is Statistics Canada as such it may differ to the CMHC data in colum B and C.
2. History of total Provincial housing starts are from the CMHC in column B and C.

Notes:

1. The CMHC first quarter 2015 forecast comes from the report located at: https://www.cmhc-schl.gc.ca/odpub/esub/65442/65442_2015_Q01.pdf?fr=1478627051917&sid=CHjR8MQPRWNu3Chhde4nShSnmTflsUyKk8PkrrqcdcE2nEpoLUrd2QYMy0He0xZ9\.
2. The CMHC fourth quarter 2016 forecast comes from the report located at: https://www.cmhc-schl.gc.ca/odpub/esub/65442/65442_2016_B02.pdf, in which the CHMC describes a range of housing starts forecast for 2016 to 2018.

131.1. Can BC Hydro explain why the CMHC Housing Start forecast is significantly higher than the Robert Fairholm Economic Consultant's forecast for the years 2016, 2017 and 2018?

132. Reference: Exhibit B-10, CEC 1.15.6

	A	B	C	D	E	F=(D*E)/1000000
Fiscal Year	Total Provincial CMHC Housing Starts Forecast (Fourth Quarter of 2016)	Total Provincial CMHC Housing Starts Forecast (Fourth Quarter of 2016)	Average Forecast CMHC Housing Starts Forecast (Fourth Quarter of 2016)	Residential Ending Number of Accounts	BC Hydro Average Use Per Account as per May 2016 Load Forecast (kWh/Account)	Residential Sales Estimate (GWh)
F2016				1,751,296		
F2017	39,300	37,700	38,500	1,789,796	10,216	18,285
F2018	34,400	32,000	33,200	1,822,996	10,104	18,420
F2019	32,000	29,700	30,850	1,853,846	10,037	18,608

Notes:

1. Column C is an average of column A and B.
2. Column D is developed by adding the average forecast housing starts to previous years' residential accounts.
3. Column E is the average use per account consistent with May 2016 forecast after demand-side management and var and voltage optimization savings.
4. Column F is the resulting residential sales forecast with the CMHC housing starts forecast.

132.1. Please clarify why Column A and Column B have the same title but different numbers.

133. Reference: Exhibit B-10, CEC 1.16.2

RESPONSE:

At the time the May 2016 Load Forecast was finalized, we assessed the state of the global economy in developing the mid load forecast. This assessment offered the following observations:

1. Most key B.C. commodity markets will continue to face weakness in the short term (i.e., next few years) due to a position of oversupply;
2. It is anticipated that a rebalancing of commodity markets will happen gradually over the next few years;
3. China's economic growth is expected to slow down over the next few years; and
4. The decline in the global commodity prices has contributed to the temporary closure of mining facilities and delay of new projects in the forecast period.

Since the May 2016 Load Forecast, we do not believe that there have been major changes to the global situation. BC Hydro's view of a gradual recovery will further enable opportunities for the B.C. industrial sector, however the extent to which these become fully realized is uncertain.

133.1. Please confirm that the last recession Canada experienced was in 2008.

133.2. Please confirm or otherwise clarify that the impact of the 2008 recession on BC Hydro's was significant and lasting.

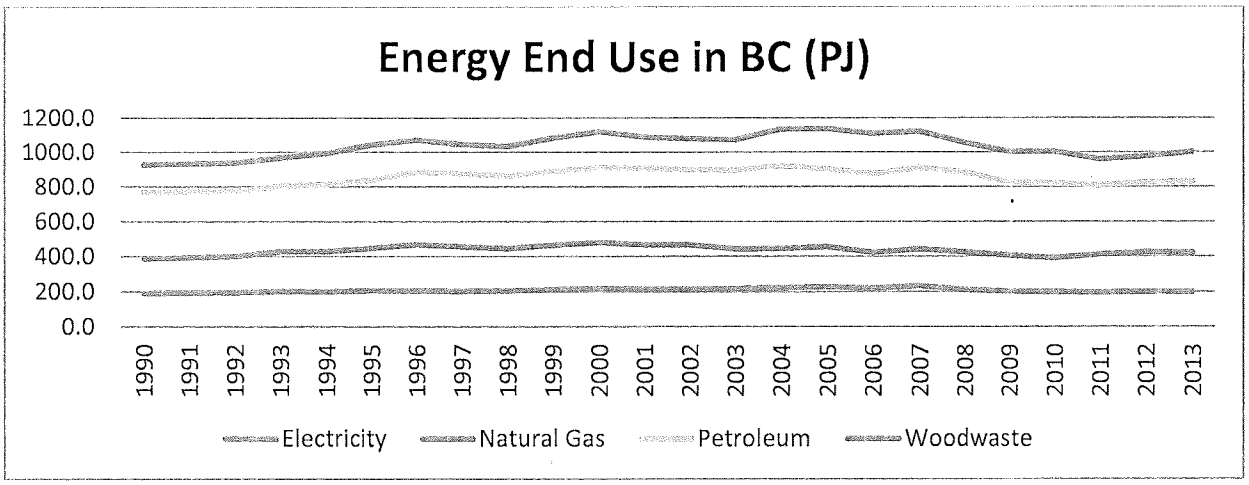
133.3. Does BC Hydro anticipate another recession within the next three to five years? Please explain why or why not.

133.4. Please provide the dates for the last 10 recessions.

133.5. Please provide BC Hydro's assessment of the impact of each of these recessions on BC Hydro's load.

133.6. Please confirm that the link http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm provides the NR Can Comprehensive Energy Use Database

133.6.1. The CEC has developed the following graph from the above information. Please discuss whether this graph validly represents energy end use in BC.



133.7. Please comment on what appears to be relatively flat consumption for electricity over the 1990-2013 period.

134. Reference: BC Hydro Website <u>https://www.bchydro.com/news/conservation/2016/rra-f17-19-explained.html</u>, Exhibit B-1-1, Page 10-1 and Page 10-2; Exhibit B-9, BCUC 1.170.1 and 1.170.2

We're spending about $2 billion a year on upgrades to meet future demand

The numbers are staggering:

- A million more people living in B.C. 20 years from now
- Over 80,000 new homes built in B.C. in the next three years alone

- An almost 40% increase in electricity demand in B.C. over the next 20 years
- 45 years is the average age our hydroelectric dams and generating stations
- Over 400,000 of our transmission and distribution towers and poles need renewal or replacement in the next 10 years.

With that picture of B.C.'s future comes a hard reality. At the same time that a drop in world commodity prices has slowed industrial sectors such as mining – cutting into BC Hydro's revenues – we need to keep spending about $2 billion a year to invest in our aging electrical system and build for future energy demand.

With forecast revenues down, we had a choice: instead of passing these issues on to customers, we gave careful thought to new measures to reduce our costs even further so we could stick to our plan to ensure low and predictable rates.

That plan is detailed in our recent filing of the Revenue Requirements Application (RRA), which determines the total amount of money we need to operate, and helps us to determine how much money we can collect from our customers through rates.

For over 25 years, BC Hydro's demand-side management programs have supported energy conservation and encouraged the adoption of more energy efficient products and equipment. Over the same period, a lot has changed. Customer acceptance of certain energy efficient products has increased, new technologies have improved access to energy data and changing customer expectations and system needs have presented new opportunities in areas such as capacity-focused demand-side management and low-carbon electrification.

process, BC Hydro reduced the average cost of its demand-side management programs to $22/MWh while remaining on track to meet the *Clean Energy Act* target to offset at least 66 per cent of incremental demand from 2008 to 2020 through conservation and maintaining the capability to acquire further demand-side management electricity savings in the future should those savings be required.

1.170.1 Please estimate the average persistence of savings (in years) of BC Hydro's F2017–F2019 DSM proposal.

RESPONSE:

The weighted average persistence of savings of BC Hydro's demand-side management activities over the period fiscal 2017 to fiscal 2019 is shown in the table below.

	Weighted Average Persistence (years)
Codes and Standards	30
Rate Structures	4
Programs	14
Total Portfolio	19

1.170.2 Please provide further information to support the $36 per MWh avoided energy cost estimate used by BC Hydro for the UCT screening filter and describe the key assumptions.

RESPONSE:

BC Hydro uses the Long Run Marginal Cost, not the $36/MWh estimate, as the primary avoided energy cost for the utility cost test by BC Hydro. The $36/MWh estimate is an extra filter to prioritize demand-side management investments. The $36/MWh estimate is the average electricity market sell price at the B.C. Border from fiscal 2017 to fiscal 2033 based on BC Hydro's current long-term electricity market price forecast. As described in section 10.3.4.1 of the Application, this extra filter ensures that even surplus energy resulting from demand-side management would still have a positive impact on BC Hydro's revenue requirements because the utility cost would be less than the market price.

134.1. Please confirm that changes in end-use technology and corresponding reductions in consumption per customer could reduce the load increases over the next 20 years.

134.2. Does BC Hydro expect innovation in conservation and efficiency technologies to continue into the future? Please explain why or why not.

134.3. Please identify the key technologies that are being developed that can be expected to impact energy use over the next 20 years.

134.3.1. Please provide an estimated time frame for each technology.

134.4. Does BC Hydro's energy load forecast anticipate known conservation and efficiency technology developments and does it anticipate development of new

energy efficiency technologies not currently known? Please explain for both known and unknown technologies.

134.5. Even though the CPR report is not yet available on the record in this proceeding, is BC Hydro aware if the CPR report identifies additional cost-effective DSM which BC Hydro can access in the future.

134.6. If BC Hydro is providing DSM at an average of $22/MWh please confirm that BC Hydro can sell this energy in the electricity markets for a profit.

134.7. Please provide a cost curve by DSM element for BC Hydro's for each of the codes and standards, programs and rate structures in BC Hydro's DSM portfolio.

134.8. Please provide the average cost of BC Hydro's DSM programs year by year for the last 10 years.

135. Reference: BC Hydro Historical and Actual Forecasts of Total Gross Requirements from: BC Hydro 2006 Integrated Electricity Plan and LTAP, Exhibit B-1A, Page 4-17 BC Hydro 2008 LTAP, Appendix D, Page 25

Figure 4-8 Comparison of Actual Total Gross Requirements to Forecast (1962-1991)

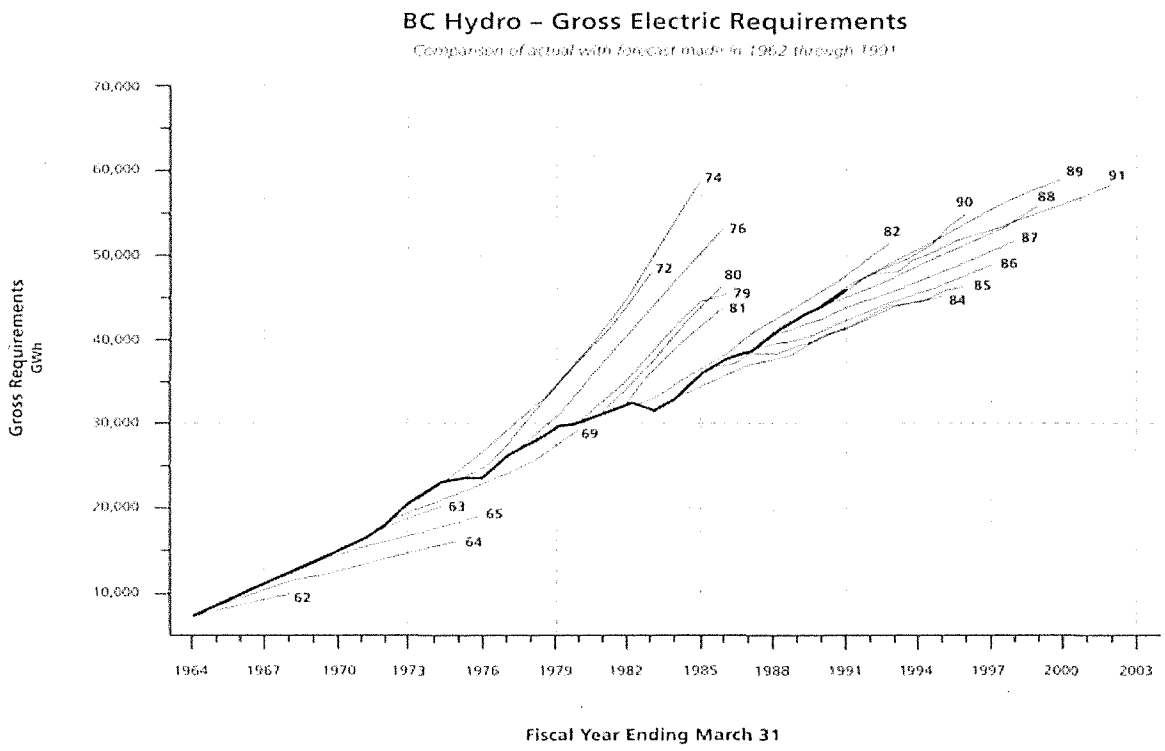
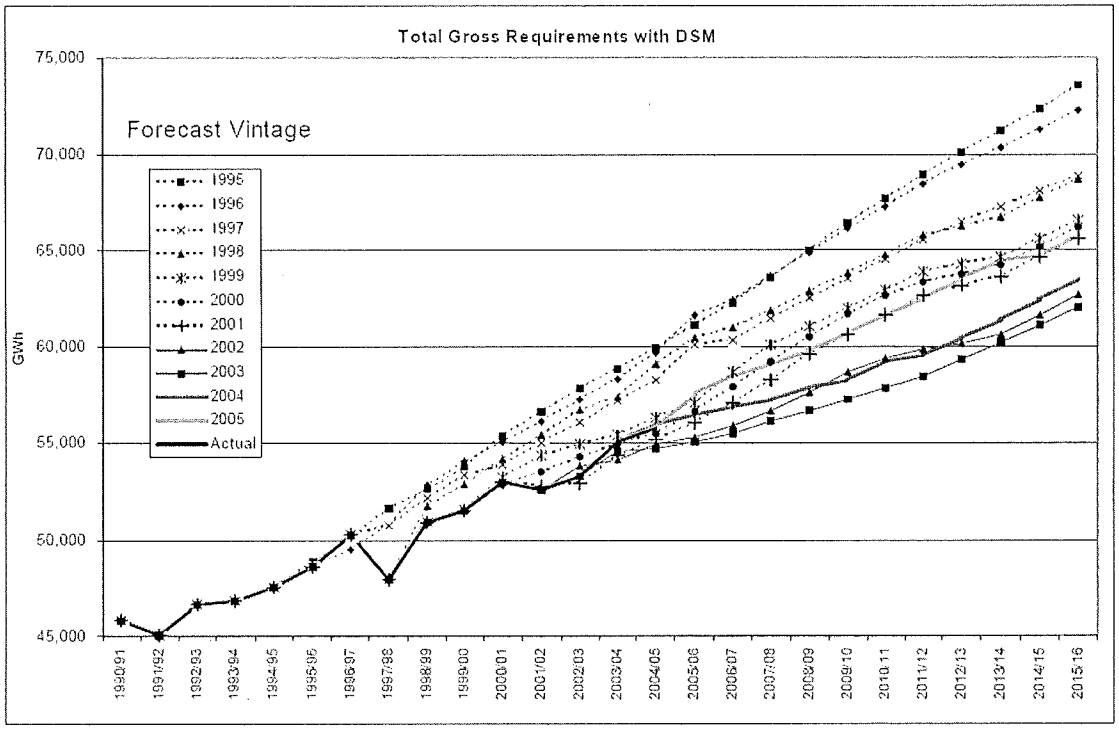


Figure 5.2 Historical Actual and Forecasts of Total Gross Requirements



135.1. Please update the above graphs showing a comparison of Actual Total Gross Requirements to Forecast from 1964 to the present and including the current forecast for the future.

135.2. The CEC wishes to understand the historical relationship between BC Hydro's forecasting and the Actual Total Gross Requirements. Please provide the full dataset of the BC Hydro annual forecasts for each year dating out 20 years, and the Actual as shown in the example table below.

	Forecast year 1964 (GWh)	1965 (GWh)	1966 (GWh)	..... (GWh)	..... (GWh)	..... (GWh)	2036 (GWh)
Forecast Vintage 1964							
1965							
1964							
1966							
.....							
2016							
Actual Total Gross Requirements							

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						

136. Reference: Exhibit B-1-1, Pages 3-6 and 3-14; Exhibit B-10, CEC 1.14.1

The central equation in estimating the residential sales forecast is the product of the number of accounts times the average use per account. The inputs are derived as follows:

- The number of account additions is based on a housing starts projection; and
- The forecasts of the residential average use per account are determined with Statistically Adjusted End Use Models.[33] The models' drivers are historical average actual use per account, economic drivers including population and disposable income, normalized temperature projections, billing days, forecasts of average appliance stock efficiencies and data from BC Hydro's residential end-use survey. Forecasts of average appliance stock efficiency come from the 2015 US Energy Information Administration average efficiency projections for the Pacific region.

Sales to the residential sector are expected to grow by about 325 GWh per year or 1.7 per cent between fiscal 2017 and fiscal 2018 and 350 GWh per year or 1.8 per cent between fiscal 2018 and fiscal 2019. This growth is mainly driven by the projection of housing starts that increases the total number of residential accounts, which are forecast to grow by 1.4 per cent per annum between fiscal 2017 and fiscal 2018 and 1.4 per cent per annum between fiscal 2018 and fiscal 2019.

1.14.1 Does BC Hydro incorporate any and all evidence that is known to it, or anticipated, regarding future circumstances that might arise and influence the load forecast? Please explain.

RESPONSE:

BC Hydro strives to produce forecasts of electricity demand that are as accurate as possible recognizing that load forecasting involves inherent uncertainty. We produce the load forecast by developing accurate, reliable, and stable models that specify the relationship between load and its key drivers, and by using reliable and credible sources for forecasts of the key drivers of load. This process includes the development of low, mid and high forecasts. For planning purposes we use the mid forecast which represents our expected outcome of load and drivers.

As stated in the Application, forecasting of LNG plant loads was approached differently from other sector forecasts. For information used for the forecast of LNG volumes reflected in May 2016 Load Forecast, please refer to section 3.2.2 of the Application.

136.1. Is it fair to say that the BC Hydro forecast load is based primarily on historical drivers and does not account for disruptive technologies, policies (government) or changes in the economy? If no, please explain why not.

137. Reference: Exhibit B-1-1, Pages 3-4 and 3-5, Exhibit B-9, BCUC 1.7.1 and Exhibit B-10, CEC 1.12.3

Forecast), and is of keen public interest. For these reasons, BC Hydro has decided to transparently include the volume of load which these proponents have announced will be supplied by BC Hydro (and for which BC Hydro has service requests) and the load estimates and in-service dates are based upon publicly available information. The LNG Load Forecast during the test period is relatively small compared to the longer-term outlook, ranging from 57 GWh in fiscal 2017 to 139 GWh in both fiscal 2018 and fiscal 2019.

- FortisBC Energy Inc. is currently constructing an expansion of its all-electric Tilbury Island LNG facility; further expansion at Tilbury is possible, but will depend on market conditions;
- LNG Canada to be located in Kitimat, has agreed with BC Hydro and the government to electricity supply terms for its ancillary loads. On July 11, 2016

  LNG Canada announced that it would be delaying its final investment decision beyond December 2017. However, this has not been reflected in this application as the impact is not yet known; and
- Woodfibre LNG to be located near Squamish, is planning to electrify both its ancillary and compression loads. It is expected to make a final investment decision within the current fiscal year. BC Hydro is currently working on an Electricity Supply Agreement with Woodfibre LNG.

By fiscal 2024, the LNG Load Forecast increases to 2,662 GWh per year which represents the total of the announced loads.

> BC Hydro also states on page 3-5 that "The LNG Load Forecast during the test period is relatively small compared to the longer-term outlook, ranging from 57 GWh in fiscal 2017 to 139 GWh in both fiscal 2018 and fiscal 2019."
>
> 1.7.1 Please provide a breakdown of LNG volume by LNG project as included in the load forecast for F2017 to F2019.

RESPONSE:

All LNG volumes are attributed to the Tilbury LNG facility. FortisBC has provided permission to BC Hydro to disclose this information for the purpose of this response.

The volumes in the load forecast for the test period are 57 GWh in Fiscal 2017, 139 GWh in Fiscal 2018 and 139 GWh in Fiscal 2019.

1.12.3 Please explain whether or not the LNG Canada and Woodfibre LNG load requirements can be considered as firm loads at this time.

RESPONSE:

As stated in section 3.2.1.1 on page 3-5 of the Application, the load forecast includes the LNG facilities that have announced they would be supplied by and have requested service from BC Hydro.

Please refer to BC Hydro's response to BCUC IR 1.7.2 for discussion about recent developments to the proposed LNG Canada and Woodfibre facilities.

137.1. Please confirm the CEC's interpretation that the load forecast includes only load from Tilbury in the test years, and no load for LNG Canada or Woodfibre.

137.1.1. If not confirmed please provide the expected load from Tilbury, LNG Canada, Woodfibre and any other project that is included in the forecast.

138. Reference: Exhibit B-10, CEC 1.20.4

1.20.4 Please provide BC Hydro's assumptions with respect to the natural gas and natural gas liquids market prices.

RESPONSE:

B.C. shale gas production is destined for three markets: the Asian LNG market, the North American natural gas market and the natural gas liquids market. BC Hydro's assumptions for these three markets are as follows:

- For the Asian LNG market, prices are expected to remain relatively low through to early 2020 as world supply of LNG continues to grow and exceed demand. However, after 2020, market prices are expected to improve as the excess supply gap progressively narrows due to retiring supply and growing demand.
- For the North American market, low cost U.S. natural gas suppliers are expected to suppress market prices in the short term. However, in the medium to long term, growing demand (from the U.S. and Mexico), and rising supply costs are expected to increase market prices and stimulate production from the low cost B.C. Montney region.
- For the natural gas liquids market, prices in the short term are expected to remain flat, but are sufficient for B.C. Montney suppliers to proceed with plant construction projects to supply gas liquids. In the medium to long term, prices are expected to increase as demand grows for gas liquids, driven by increased demand for diluent in the Alberta oil sands.

For further information regarding BC Hydro's data sources please refer to BC Hydro's response to CEC IR 1.20.2.

138.1. Does BC Hydro agree that LNG market prices after 2020 may have a considerable range of uncertainty with respect to the degree of any anticipated improvement?

138.2. Please discuss whether or not competing LNG projects in other parts of the world including US brownfield sites may have competitive advantages over greenfield LNG projects in BC.

139. Reference: Exhibit B-10, CEC 1.23.1; Exhibit B-1-1, Page 3-13, Table 3-2 and Page 3-16

23.0 Reference: Exhibit B-1-1, Page 3-20

Table 3-4 Fiscal 2017 to Fiscal 2019 Domestic Energy Sales Forecast Less Demand-Side Management - Plan

	(GWh)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Residential	18,805	17,047	18,743	17,331	18,036	18,112	18,250
2	Light Industrial and Co	18,277	18,564	18,346	18,421	18,832	18,785	18,869
3	Large Industrial	14,444	14,020	15,032	13,669	13,380	13,323	13,802
4	Other	1,604	1,567	1,638	1,602	1,611	1,618	1,634
5	Total	53,130	51,199	53,759	51,023	51,860	51,838	52,804

1.23.2 Please supply a ballpark +/- % range of variation that might reasonably be expected to occur in each of the classes.

RESPONSE:

BC Hydro does not estimate a plus or minus range for the load forecast, rather, we calculate a high and low load forecast range. Our high and low load forecast range is provided in section 3.2.2, Table 3-2 of the Application.

Table 3-2 Fiscal 2017 to Fiscal 2019 Domestic Energy Sales Forecast (Mid, Low, High)

	(GWh)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Residential	18,805	17,047	18,743	17,331	18,654	18,979	19,327
2	Light Industrial and Commercial	18,277	18,564	18,346	18,421	19,212	19,360	19,655
3	Large Industrial	14,444	14,020	15,032	13,669	13,752	13,936	14,555
4	Other	1,604	1,567	1,638	1,602	1,611	1,618	1,634
5	Total Mid Domestic Sales	53,130	51,199	53,759	51,023	53,229	53,894	55,171
6	Total Low Domestic Sales	53,130	51,199	53,759	51,023	51,100	51,468	52,259
7	Total High Domestic Sales	53,130	51,199	53,759	51,023	55,371	56,415	58,255

Table 3-3 Fiscal 2017 to Fiscal 2036 - Large Industrial Sales Forecasts

	GWh (Note 3)		Large Industrial Sub Sectors: Oil and Gas	Coal and Metal Mining	Forestry	Other	Total Sales	LNG (Note 1)	LOW (Note 2) Total Large Industrial Sales with LNG	MID (Note 2) Total Large Industrial Sales with LNG	HIGH (Note 2) Total Large Industrial Sales with LNG
			1	2	3	4	5	6	7	8	9
1	Actual	F2015	1,113	3,798	7,938	1,171	14,020		14,020	14,020	14,020
2	Actual	F2016	1,274	3,875	7,374	1,147	13,669		13,669	13,669	13,669
3	Forecast	F2017	1,639	3,804	7,547	1,204	13,695	57	13,220	13,752	14,346
4	Forecast	F2018	1,993	3,728	8,601	1,276	13,797	139	13,333	13,935	14,831
5	Forecast	F2019	2,652	3,834	8,593	1,337	14,416	139	13,812	14,555	15,417
6	Forecast	F2022	3,223	4,054	8,137	1,408	14,822	2,148	15,876	16,970	18,268
7	Forecast	F2027	3,827	4,063	5,592	1,614	15,296	2,662	16,554	17,958	19,872
8	Forecast	F2036	4,100	4,100	5,740	1,634	15,574	2,662	16,493	18,236	20,359

Note:
1. LNG sales in column 6 is based on announced LNG as described in section 3.2.1.1
2. LNG sales in column 6 is also included in the low, mid and high sales projections in columns 7,8,9
3. All sales figures in table above excluded losses.

139.1. Please complete the following tables:

Residential Sales GWh	Low	Mid	High
F2017			
F2018			
F2019			
F2022			
F2027			
F2036			

Commercial/Light Industrial Sales	Low	Mid	High
F2017			
F2018			
F2019			
F2022			
F2027			
F2036			

139.2. Please provide a discussion of the key factors that drive the differences between the forecast and each of the low, and high forecast for each rate class (residential, commercial/light industrial, large industrial).

140. Reference: Exhibit B-10, CEC 1.25.3

1.25.3 In what ways could BC Hydro modify the operations to change the revenue requirements? Please explain and provide quantification.

RESPONSE:

BC Hydro optimizes its supply portfolio to maximize consolidated net revenue over a five-year time horizon (refer to section 4.3.2 of the Application). Deviations from this optimal operation within this period would have a detrimental impact on total net revenue over the period. We have consistently applied this approach in the last ten years of revenue requirements applications.

Any sub-optimal operation of the system aimed at managing Cost of Energy in the short-term would increase the long-term cost to ratepayers. Any forecasting at other than expected values will likely create biased rate setting and systematic over- or under- collecting with respect to costs.

The deferral accounts permit the system to be operated optimally and avoids sub-optimal (higher long-term cost) outcomes associated with operating goals that target revenues within shorter time frames, such as the three-year test period.

140.1. If BC Hydro is over-forecasting please explain the bias in rate setting and systematic over-collection with respect to costs which would occur as a consequence of the over-forecasting.

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.

141. Reference: Exhibit B-10, CEC 1.26.1

1.26.1 Please provide the assumptions for the Low Load forecast.

RESPONSE:

The high and low Integrated Total System Gross Requirements load forecasts are both derived from BC Hydro's Monte Carlo Uncertainty Analysis which is described in section 3.2.1.7 of the Application.

The main assumptions for the model are the distribution for the key uncertainty variables contained in the model which are:

1. Variation in the economy represented by Provincial real Gross Domestic Product (GDP) growth. The normal distribution for real GDP growth has a standard deviation of 1.9 per cent. This distribution applies to the residential, light industrial and commercial sales and is correlated with sales within the large industrial sector.

2. Weather variation which applies to the residential and light industrial and commercial sectors. In British Columbia, the impact of cold weather on residential heating load is the most important weather effect and is modeled

using heating degree days. The weather uncertainty is based on a standard probability distribution of the Beta type, which was the best fit to historical heating degree days. The distribution has a maximum of 3,541, a minimum of 2,948 and a mean of 3,200 heating degree days. The mean, maximum and minimum heating degree days are a sales weighted total across all four regions of BC Hydro's service area.

Uncertainty in the large industrial sales is represented by the high and low forecasts for forestry, oil and gas, mining and the remaining portion of the large industrial sector. The high and low forecasts, along with the mid forecasts, are used to determine the end points of a triangular distribution for each of these sectors. The mid high and low total large industrial forecasts are provided in Table 3-3 of the Application.

141.1. Please provide an estimate of what percentage of the BC Hydro load is heat sensitive to variations in degree days.

141.2. Please provide the anticipated load increase for each added heating degree day.

141.3. Please identify whether or not BC Hydro's load forecasting anticipates any change in the heating degree days provided above.

141.3.1. If yes, what changes are anticipated? Please explain and provide quantification.

142. Reference: Exhibit B-10, CEC 1.28.1

3.4.2.2 Accounting For Uncertainties on the Load Resource Balances

BC Hydro continues to monitor its Load Resource Balance as it faces significant uncertainties. The magnitude of the uncertainty is shown by the range of surplus/deficit presented in each of the load resource balances in Table 3-8 and Table 3-9. Considering these uncertainties, the Load Resource Balance with planned resources (Table 3-9) shows that additional capacity resources may be needed as early as fiscal 2019.[23]

[23] The risk of capacity shortfall is BC Hydro's primary concern because, unlike energy, capacity is required at specific times to meet load requirements and maintain system security and reliability.

1.28.1 Please confirm or otherwise clarify that interruptible rates can provide capacity benefits.

RESPONSE:

Interruptible rates can provide capacity benefits. The value of interruptible rates depends on their cost to BC Hydro and how well the resulting load reduction meets the characteristics of our system's capacity needs.

142.1. Please describe how interruptible rates can best be used to meet the characteristics of the system's capacity needs.

143. Reference: Exhibit B-10, CEC 1.31.1

> 1.31.1 What would be the revenue requirement impact if BC Hydro were to achieve 100% of forecasted energy load increase by fiscal 2021 with LNG?
>
> RESPONSE:
>
> In BC Hydro's response to BCUC IR 1.169.5, BC Hydro explains that the 2013 IRP Alternative was an alternative demand-side management portfolio that we compared and analyzed. BC Hydro estimates that 99 per cent of incremental load growth by fiscal 2021, with LNG, would be met under this alternative. This is very close to the 100 per cent referenced in the question above.
>
> BC Hydro notes, that since the fiscal 2017 to fiscal 2019 rates are capped by Direction No. 7, the impacts on customer rates of pursuing an alternative demand-side management portfolio would occur over subsequent years of the 2013 10 Year Rates Plan. Relative to the proposed Demand-Side Management Plan, the 2013 IRP Alternative would decrease the revenue requirement by approximately $36 million over the fiscal 2017 to fiscal 2024 period. In addition, as per BC Hydro's response to BCUC IR 1.169.5, we have estimated the overall relative rate increase that would result under the 2013 IRP Alternative to be approximately 0.5 per cent per year over the fiscal 2020 to fiscal 2024 period.

143.1. If pursuing the Alternative would decrease the revenue requirement of $36 million over the fiscal 2017 to 2024 period, would it represent a $4.5 million decrease in revenue requirements per year? Please explain.

143.1.1. What is the rate decrease that would be represented by the $4.5 million, or the $36 million?

143.2. How does the decrease in the revenue requirement of $36 million related to the estimated relative rate increase over the 2020-2024 period? Please discuss.

143.3. Is the 0.5 per cent per year increase a cumulative set of rate increases, such that over 5 years a rate increase of 2.5% is experienced, or is it a one-time 0.5% that is present with the impact being maintained for the 5 years. Please explain.

144. Reference: Exhibit B-10, CEC 1.30.3 and CEC 1.32.1

> 1.30.3 Please provide the supply resource BC Hydro is proposing to acquire and or renew during this same time period.
>
> RESPONSE:
>
> BC Hydro understands the question is referring to the IPP supply resources that BC Hydro is proposing to acquire or renew within the test period.
>
> As discussed in section 4.4.2.3 of the Application, on page 4-18, during the test period BC Hydro is expecting to acquire new supply resources with the Standing Offer Program, including the Micro-Standing Offer Program and with the potential acquisition of electricity from one co-gen facility. Apart from these resources, no new power acquisitions from IPPs are planned in the test period.
>
> With respect to renewals, as described in BC Hydro's response to BCUC IR 1.18.2, BC Hydro has 13 Electricity Purchase Agreements up for renewal in the integrated area during the test period. BC Hydro has signed new Electricity Purchase Agreements with two of these IPPs, Akolkolex and Soo River, and BC Hydro submitted these agreements to the BCUC for acceptance, pursuant to section 71 of the *Utilities Commission Act*, on September 15, 2016. As discussed in BC Hydro's response to BCUC IR 1.18.1, the renewal assumptions are applied to aggregate energy and capacity volumes rather than to the number of contracts for the applicable bioenergy and run-of-river IPP projects within BC Hydro's integrated area because the contracts to be renewed are unknown until renewal agreements are reached with the counterparties.

144.1. Please provide the total aggregate energy and capacity volumes of the supply resources that BC Hydro is likely to renew.

144.2. Please provide, in the aggregate, the energy and capacity volumes of the new Electricity Purchase Agreements with Akolkolex and Soo River that BC Hydro has submitted for acceptance.

144.3. Please confirm, or otherwise explain that the alternative for an IPP in the event that it does not renew is to sell into the spot market or to enter into a longer term with a potential customer.

144.4. Please provide BC Hydro's assessment of the market for longer term contracts with potential customers, and the expected prices for energy and capacity for such contracts.

144.5. Is BC Hydro's renewal policy to price energy at market value when BC Hydro expects to be in surplus, and then at marginal cost when it needs more energy? Please explain.

145. Reference: Exhibit B-10, 1.32.3 and 1.32.1.1

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.

If BC Hydro were to reduce its resources, the impact to the revenue requirements would depend on which resources are reduced, when and by how much. We believe our currently planned actions are still appropriate given the updated load resource balance. Any resource reduction in the near term could potentially advance the need for more costly supply in the longer term.

BC Hydro has not undertaken the work needed to determine which resources it would further reduce if that were required and hence it is not able to provide the impact to the revenue requirements requested. The load resource balance in the Application reflects the results of past acquisitions as well as planned resources/actions pursuant to the Recommended Actions set out in the Government-approved 2013 IRP (with a moderation of the demand-side management expenditures as supported by the Minister as expressed in his letter dated December 16, 2015). This ensures reliable and cost effective electricity service both in the near and long-term while balancing multiple policy objectives. In particular, the load resource balance reflects results from BC Hydro carrying out Recommended Action No. 4 in the Integrated Resource Plan to terminate, downsize and defer pre-commercial date Electricity Purchase Agreements and that work is now complete. Any further reduction on existing Electricity Purchase Agreements is expected to come with significant legal challenge and additional costs that could increase our revenue requirements.

BC Hydro also notes that any excess may be reduced by increasing load. The impact to the revenue requirements from increasing load would depend on which rate class the increased sale is in and by how much. BC Hydro expects additional electrification load to be driven by the Climate Leadership Plan.

BC Hydro is required to purchase non-firm energy under most IPP Electricity Purchase Agreements. As referenced in BC Hydro's response to BCUC IR 1.17.3, some of our Electricity Purchase Agreements, such as those offered under our Standing Offer Program, include mechanisms to limit energy purchase commitments through hourly or annual caps on eligible energy.

	F2017 Plan	F2018 Plan	F2019 Plan
Non-Firm Purchase Volumes (GWh)	5,329	5,695	5,804
Average Unit Cost ($/MWh)	57.9	59.6	63.9

As of May 1, 2016 for projects connected to or planned to connect to the integrated grid.

145.1. Please complete and/or revise the following table.

	F2017	F2018	F2019
Excess Over Forecast (GWh)	4,945	4,928	3,524
IPP non-firm (GWh)	5,329	5,695	5,804
IPP non-firm cost ($/MWh)	57.9	59.6	63.9
Total IPP non-firm cost			
IPP existing firm (GWh)			
IPP existing firm cost			
Total IPP firm cost			

145.2. If BC Hydro had not agreed to purchase non-firm energy from IPPs at these prices and instead had bought the energy at market prices, would BC Hydro be able to manage its energy needs without surpluses or excess over load forecast? Please explain.

145.3. Please confirm that the anticipated non-firm market for sale of energy would have an estimate price of $36/MWh over the next three years.

146. Reference: Exhibit B-9, BCUC 1.18.2

		Fiscal 2017	Fiscal 2018	Fiscal 2019	Fiscal 2017-2019 Average
Volume (GWh)					
1	Existing IPPs	13,198	14,592	14,337	14,042
2	IPP Renewals	106	280	571	319
3	Other	71	130	291	164
4	Total IPP	13,375	15,002	15,199	14,526
Number of contracts					
5	Existing IPPs	121	114	114	116
6	IPP Renewals	Unknown	Unknown	Unknown	Unknown
7	Other	Unknown	Unknown	Unknown	Unknown
8	Total IPP	Unknown	Unknown	Unknown	Unknown
Cost ($/MWh)					
9	Existing IPPs				
10	IPP Renewals				
11	Other	109.95	103.95	100.35	102.69
12	Total IPP	92.3	91.3	94.7	92.8

		Fiscal 2017	Fiscal 2018	Fiscal 2019	Fiscal 2017-2019 Average
Cost including Accounting Adjustments ($ million)					
13	Existing IPPs	[redacted]			
14	IPP Renewals				
15	Other	7.8	13.6	29.2	16.9
16	Total IPP	1,234.4	1,369.7	1,439.3	1,347.8

146.1. Is BC Hydro obligated to renew any or all IPP or Other contracts?

146.1.1. If yes, please provide the volume of IPP or Other contracts and the number of contracts that BC Hydro is obligated to renew by year.

146.1.2. If no, could BC Hydro defer or not renew contracts? Please explain why or why not.

146.1.3. Please confirm the benefit for ratepayers in the test period of not renewing in each year is the cost of the energy renewed less the value BC Hydro can receive for that energy in the marketplace.

147. Reference: Exhibit B-1-1, Page 3-39 and 4-20; Exhibit B-10, CEC 1.32.1, CEC 1.39.2 and CEC 1.101.1

Subsequent to the 2013 Integrated Resource Plan, BC Hydro determined that it is appropriate to continue a moderation strategy for demand-side management and still achieve the 66 per cent target in 2020 in the *Clean Energy Act.*[26] Spending through the fiscal 2017 to fiscal 2019 period will be reduced to approximately $375 million over the three year period (and average of $125 million/year), while maintaining the ability to ramp up after fiscal 2019 if warranted.

For fiscal 2017 through fiscal 2019, IPPs are expected to provide about 23 per cent of BC Hydro's energy supply. Cost of energy for IPPs and long-term commitments after accounting adjustments as reflected in Table 4-10, makes up roughly 29 per cent of BC Hydro's revenue requirements, with an average cost of $93/MWh over this forecast period.

1.32.1 Does BC Hydro anticipate terminating or renewing any IPP agreements during the test period?

1.32.1.1 If yes, what are the cost savings that would likely accrue from these terminations?

RESPONSE:

The public version of the response to this information request has been redacted to maintain in confidence commercially sensitive information. The unredacted version of this response is being filed in confidence with the Commission as public disclosure could impact BC Hydro's commercial interests and ongoing negotiations related to the Electricity Purchase Agreement renewals.

BC Hydro estimates savings of [redacted] during the test period from terminating the 13 identified Electricity Purchase Agreements referenced in BC Hydro's response to CEC IR 1.32.1 and proceeding with the assumed IPP renewals at a forecast cost provided in line 14 of BC Hydro's response to BCUC IR 1.18.2. This [redacted] cost saving is already reflected in the test period forecast and includes an adjustment for estimated lost surplus value.

BC Hydro is required to purchase non-firm energy under most IPP Electricity Purchase Agreements. As referenced in BC Hydro's response to BCUC IR 1.17.3, some of our Electricity Purchase Agreements, such as those offered under our Standing Offer Program, include mechanisms to limit energy purchase commitments through hourly or annual caps on eligible energy.

	F2017 Plan	F2018 Plan	F2019 Plan
Non-Firm Purchase Volumes (GWh)	5,329	5,695	5,804
Average Unit Cost ($/MWh)	57.9	59.6	63.9

As of May 1, 2016 for projects connected to or planned to connect to the integrated grid.

1.101.1 Does BC Hydro expect the costs of its DSM programs to continue to decline over the test period?

RESPONSE:

No, the $22/MWh in the reference is the levelized cost of BC Hydro's demand-side management program activity over the timeframe from fiscal 2016 to fiscal 2024.

While an individual year may have a levelized cost higher or lower than $22/MWh, the demand-side management plan proposed in the Application was not designed with the intent of continuing to decrease levelized costs over time.

BC Hydro calculates the levelized cost of demand-side management over a multi-year timeframe. Limiting the analysis to a shorter period of time may not fully capture inter-year effects.

147.1. Does BC Hydro have the opportunity to displace the purchase/renewal of IPP energy with additional DSM at an average cost of $22/MWh?

147.1.1. If no, please explain why not.

147.1.2. If yes, please identify how much energy could be displaced with DSM, and the revenue requirement impact of that displacement.

147.2. What is the 'lost surplus value' as referenced in CEC 1.32.1.1 that BC Hydro is using in regard to terminated IPP contracts?

148. Reference: Exhibit B-10, CEC 1.41.3 and 1.41.4

1.41.3 What would the IPP alternatives sales opportunities be for their projects if BC Hydro did not make the renewal purchase

RESPONSE:

In the absence of an Electricity Purchase Agreement renewal with BC Hydro, an IPP may be able to sell energy to another party. Such sales could be to other B.C. utilities (e.g., FortisBC), US or Alberta markets, or potentially to retail loads in FortisBC's service area. To enable these sales the use of BC Hydro's Open Access Transmission Tariff would be required.

RESPONSE:

BC Hydro interprets "anticipated load curve" to mean the anticipated timing of the need for new supply under the planning view of the load resource balance which is described on pages 3-27 and 3-28 of the Application and set out in Table 3-6 of the Application (as revised in BC Hydro's response to BCUC IR 1.11.1).

BC Hydro could contract for renewals with IPPs to match anticipated load curves; however, such an approach does not provide BC Hydro with certainty as discussed below.

Recommended Action 4 in BC Hydro's 2013 IRP indicated that BC Hydro would optimize its portfolio according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need. BC Hydro plans for and acquires resources to match its anticipated load curves on a long-term and cost-effective basis. This includes IPP renewals.

Delaying renewal of IPP Electricity Purchase Agreements, as would be the case if BC Hydro were to match anticipated load curves, would not allow BC Hydro to plan with certainty on a long-term basis. Assuming upon expiration of an Electricity Purchase Agreement, BC Hydro would not require an IPP's energy until a later time and chooses not to renew the Electricity Purchase Agreement with the IPP, then the IPP may either commit its resource to another buyer or may choose to decommission its facilities. In either case, BC Hydro has potentially lost the opportunity to include this resource within its resource stack. The risk to BC Hydro is that at a later time, this existing resource would either not be available or BC Hydro may not be able to contract for this resource on cost-effective basis. BC Hydro would then need to acquire energy from new greenfield energy resources.

If the negotiated energy price in a renewed Electricity Purchase Agreement is lower than BC Hydro's opportunity cost and if the energy price being paid under Electricity Purchase Agreement is cost-effective during the term of the agreement, then it is likely more cost-effective to enter into renewal agreements with IPPs as their contracts expire.

148.1. Please provide any studies that BC Hydro conducted with regard to its approach to renewal of IPP contracts that determined the values of contract flexibility to match anticipated load curves to varying degrees.

148.2. Please provide any studies that evaluated the merits of holding IPP contracts while BC Hydro is in surplus for a future requirement.

149. Reference: Exhibit B-10, CEC 1.47.2 and 1.47.1

1.47.2 What is the total expected impact of the forecast increases for management and professional staff?

RESPONSE:

The average annual labour cost increase is forecast to be $7.5 million per year through the test period, of which $3 million per year is for management and professional staff.

47.0 Reference: Exhibit B-1-1, Page 5-21

- Labour costs (excluding Workforce Optimization) of $4.9 million in fiscal 2017. These expenditures cover increases under BC Hydro's collective agreements, which mirror those provided under the Province's bargaining mandate. Salary increases for management and professional staff have been limited and targeted in recent years, and are planned to increase at the same rate as the collective agreements during the test period; and

1.47.1 Are management and professional staff increases tied to the results of collective agreements?

RESPONSE:

Management and Professional (M&P) staff increases are not tied to the results of collective agreements. It is forecast that M&P salaries will increase by 1.5 per cent per year over the test period, which is similar to the forecast Union wage increase of 1.9 per cent per year over the test period. M&P increases for the test period are not finalized or approved and will depend on factors such as budget constraints, labour market conditions, and Public Sector Employers Council guidelines.

149.1. Please provide a graph depicting BC Hydro total M&P salaries and benefits over the last 20 years.

149.2. Please provide a graph depicting BC Hydro M&P salary increases over the last 20 years.

150. Reference: Exhibit B-1-1, Page 5-31 and Exhibit B-10, CEC 1.48.5.2

Table 5-10 Weighted Average Standard Labour Rates by Affiliation

F2017 Plan			
($ per hour)	MoveUp	IBEW	M and P
Standard Labour Rates, F2016 Plan	55.33	69.90	93.88
Forecast weighted average base pay increase/(decrease)	2.20	1.91	1.43
Benefit Costs			
Forecast current pension costs increase/(decrease)	1.09	0.75	1.30
Forecast other benefit costs increase/(decrease)	0.16	(0.18)	(0.08)
Forecast premium and allowance increase/(decrease)	0.03	1.53	(0.11)
Forecast gainsharing/results pay increase/(decrease)	0.08	0.07	0.23
Total Rate Increase/(Decrease)	**3.56**	**4.08**	**2.85**
Standard Labour Rates F2017 Plan	**58.89**	**73.97**	**96.73**

F2018 Plan			
($ per hour)	MoveUp	IBEW	M and P
Standard Labour Rates, F2017 Plan	58.89	73.97	96.73
Forecast base pay increase	0.82	0.93	1.10
Benefit Costs			
Forecast current pension costs increase	0.14	0.14	0.17
Forecast other benefit costs increase	0.23	0.24	0.33
Forecast premium and allowance increase	0.01	0.04	(0.00)
Forecast gainsharing/results pay increase	0.03	0.03	0.00
Total Rate Increase	**1.21**	**1.39**	**1.60**
Standard Labour Rates F2018 Plan	**60.10**	**75.36**	**98.33**

F2019 Plan			
($ per hour)	MoveUp	IBEW	M and P
Standard Labour Rates F2018 Plan	60.10	75.36	98.33
Forecast base pay increase	0.83	0.95	1.11
Benefit Costs			
Forecast current pension costs increase	0.15	0.16	0.19
Forecast other benefit costs increase	0.28	0.30	0.42
Forecast premium and allowance increase	0.01	0.04	(0.00)
Forecast gainsharing/results pay increase	0.03	0.03	0.00
Total Rate Increase	**1.30**	**1.48**	**1.72**
Standard Labour Rates F2019 Plan	**61.40**	**76.85**	**100.05**

1.48.5.2 If yes, please provide BC Hydro's estimate of the total cost of the bonus/incentive structure and the percentage of the bonus/incentive structure relative to total compensation for M&P.

RESPONSE:

As noted in BC Hydro's response to CEC IR 1.48.5, most Management and Professionals do not participate in a bonus or incentive program. The exception is for Executives and Directors who have a salary holdback program.

BC Hydro's estimate of the salary holdback program is $1.4 million annually in the test period. As stated in BC Hydro's response to CEC IR 1.48.5, the actual salary holdback paid is calculated based on individual and corporate performance at the end of each fiscal year and could therefore differ from the estimate.

150.1. Please confirm that the $1.4 million in the salary holdback is represented by the $0.23/hour Forecast gainsharing.

150.1.1. If not, please rationalize.

151. Reference: Exhibit B-10, CEC 1.50.1

Forecast Assumptions used in the Application

Key Assumptions	2014/15 Actual	2015/16 Actual	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
Growth and Load					
B.C. Real Gross Domestic Product Growth (%)	3.2	2.4	2.4	2.3	2.3
Domestic Sales Load Growth (%)	(3.41)	11.89	(0.83)	1.01	(0.37)
Residential Sales Load Growth (%)	(5.11)	1.67	4.07	0.42	0.77
Light Industrial and Commercial Sales Load Growth (%)	0.34	(0.77)	2.23	(0.25)	0.61
Large Industrial Sales Load Growth (%)	0.19	(2.50)	(2.53)	(1.04)	4.24
Domestic Load (GWh):					
Domestic Sales Volume (GWh)	51,213	57,300	56,822	57,394	57,181
Line Loss and System Use (GWh)	4,529	5,836	5,303	5,349	5,425
Total Domestic Load (GWh)	55,742	63,136	62,125	62,743	62,606
Energy Generation					
Total System Water Inflows (% of average)	102	97	98	100	100
Sources of Supply to Meet Domestic Load:					
Net Hydro Generation (GWh)	41,830	48,370	48,178	46,642	46,118
Market Electricity Purchases (GWh)	207	122	230	747	934
Independent Power Producers and Long-term Purchases (GWh)	13,377	14,319	13,375	15,002	15,199
Thermal Generation (GWh)	328	326	342	352	355
Sources of Supply for Domestic Load (GWh)	55,742	63,136	62,125	62,743	62,606
Average Mid-C Price (U.S.$/MWh)	27.16	23.12	21.38	25.08	26.28
Average Natural Gas Price at Sumas (U.S.$/MMBTU)	3.55	2.15	2.19	2.66	2.71
Financial					
Canadian Short-Term Interest Rates (%)	1.22	0.87	0.72	1.40	2.03
Canadian Long-Term Interest Rates (%)	2.83	2.37	2.96	3.67	4.60
Foreign Exchange Rate (U.S.$:Cdn$)	0.8782	0.7625	0.7381	0.7783	0.8020

The table above has been prepared in the presentation format consistent with the Service Plan, and therefore categories and totals may not correspond directly with amounts in Appendix A or elsewhere in the Application. For example, the presentation of Domestic Sales Volume in the Service Plan assumptions (and thus in the tables above and below) includes surplus sales volumes, whereas in the Application these are presented separately.

Additionally, please refer to the table below, which includes updates to the forecast assumptions that BC Hydro used in the Application.

Updated Forecast Assumptions

Key Assumptions	2014/15 Actual	2015/16 Actual	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
Growth and Load					
B.C. Real Gross Domestic Product Growth (%)	3.2	2.7	2.7	2.2	2.3
Domestic Sales Load Growth (%)	(3.41)	11.89	(0.27)	(1.19)	0.24
Residential Sales Load Growth (%)	(5.11)	1.67	1.89	2.57	0.77
Light Industrial and Commercial Sales Load Growth (%)	0.34	(0.77)	2.22	(0.24)	0.61
Large Industrial Sales Load Growth (%)	0.19	(2.50)	(3.92)	0.38	4.24
Domestic Load (GWh):					
Domestic Sales Volume (GWh)	51,213	57,300	57,143	56,464	56,598
Line Loss and System Use (GWh)	4,529	5,836	5,301	5,349	5,425
Total Domestic Load (GWh)	55,742	63,136	62,444	61,813	62,023
Energy Generation					
Total System Water Inflows (% of average)	102	97	95	100	100
Sources of Supply to Meet Domestic Load:					
Net Hydro Generation (GWh)	41,830	48,370	47,738	45,853	45,665
Market Electricity Purchases (GWh)	207	122	428	691	860
Independent Power Producers and Long-term Purchases (GWh)	13,377	14,319	13,943	14,918	15,145
Thermal Generation (GWh)	328	326	335	351	353
Sources of Supply for Domestic Load (GWh)	55,742	63,136	62,444	61,813	62,023
Average Mid-C Price (U.S.$/MWh)	27.16	23.12	24.24	25.15	25.10
Average Natural Gas Price at Sumas (U.S.$/MMBTU)	3.55	2.15	2.56	2.83	2.64
Financial					
Canadian Short-Term Interest Rates (%)	1.22	0.87	0.59	0.76	1.73
Canadian Long-Term Interest Rates (%)	2.83	2.37	2.11	2.53	3.50
Foreign Exchange Rate (U.S.$:Cdn$)	0.8782	0.7625	0.7641	0.7808	0.8020

151.1. Please relate the Average Mid-C price to the previously quoted surplus sales value of $36/MWh.

152. Reference: Exhibit B-10, CEC 1.59.1 and Exhibit B-1-1, Pages 5-9 and 5-10

1.59.1 What are the total costs of changes in the Smart Metering and Infrastructure program?

RESPONSE:

The following response is expanded to answer CEC IRs 1.59.1, 1.59.2 and 1.59.3.

BC Hydro notes that the Smart Metering and Infrastructure creates additional energy cost reductions that are not captured in operating costs, resulting in an overran net positive benefit to rate payers.

The incremental operating costs, savings and net impacts through the test period are provided below. Please also refer to Table 5-2 of the Application for additional details supporting the totals below.

	F2017 ($ million)	F2018 ($ million)	F2019 ($ million)
Incremental Operating Costs	44.3	43.1	43.2
Operating Cost Savings	(22.1)	(22.4)	(22.6)
Total	22.2	20.7	20.6

The Smart Metering and Infrastructure Program Completion and Evaluation Report is scheduled to be filed with the British Columbia Utilities Commission as part of this proceeding, and will include the overall NPV impacts.

Table 5-2 does not include other benefits related to the implementation of Smart Metering and Infrastructure such as theft reduction as shown in Chapter 3, Table 3-6, Table 3-7, Table 3-8 and Table 3-9.

Table 5-2 Incremental Operating and Maintenance Costs, Operating Cost Savings and FTEs from Smart Metering and Infrastructure Sustainment Activities

	Fiscal 2017				Fiscal 2018				Fiscal 2019			
Business Group/Key Business Unit	Incremental Operating Costs	Operating Cost Savings	Total Net Incremental Cost	FTEs	Incremental Operating Costs	Operating Cost Savings	Total Net Incremental Cost	FTEs	Incremental Operating Costs	Operating Cost Savings	Total Net Incremental Cost	FTEs
Transmission Distribution and Customer Service												
Asset Management and Distribution Engineering	1.0		1.0	1	-	-	-	-	-	-	-	-
Customer Service and Distribution Design	14.4	(19.7)	(5.3)	2	(1.2)	(0.2)	(1.4)		0.1	(0.2)	(0.1)	
Field and Grid Operations	3.1	(1.4)	1.7	23	-	-	-	-	-	-	-	-
Technology	25.6	-	25.6	25	-	-	-	-	-	-	-	-
Operations Support												
Finance and Supply Chain	0.1	(1.0)	(0.9)		-	-	-	-	-	-	-	-
Totals	44.3	(22.2)	22.1	51	(1.2)	(0.2)	(1.4)	-	0.1	(0.2)	(0.1)	-

152.1. Please confirm that the $22.2 million, $20.7 million and $20.6 million identified in CEC 1.59.1 for F2017 to F2019 represent the full cost and benefits of Smart Metering Infrastructure.

152.2. If not, please provide the full cost and benefit statement for the Smart Metering Infrastructure.

153. Reference: Exhibit B-10, CEC 1.62.1.1, CEC 1.32.1.1 and CEC 1.83.1

1.62.1 Please provide a brief discussion of the types of 'customer initiated' projects that BC Hydro undertakes totaling approximately $15 million.

1.62.1.1 Do all customers pay for the customer related projects or pay a portion of those identified above?

RESPONSE:

All customers who trigger these "customer initiated projects" contribute towards the costs.

For a new distribution load customer request for service, costs are allocated per section 8 of the Electric Tariff (Distribution Extensions – 35 kV or less). Specifically, the customer pays for the cost of the extension facilities to allow connection to BC Hydro's system, less a contribution from BC Hydro as specified in section 8.3 of the Electric Tariff. In addition, those customers with a total Maximum Demand over 500 kVA will pay the System Improvement Costs as part of this fee.

Third parties that request relocations of BC Hydro distribution infrastructure are required to reimburse BC Hydro for the full cost of the relocations. However, BC Hydro does have protocol agreements with some governmental bodies, such as the Ministry of Transportation and Infrastructure, which establishes a cost sharing mechanism for these relocations depending on the types of facilities being relocated.

For a new distribution IPP interconnection project, the IPP is required to construct the facilities from its generating plant to the BC Hydro system. BC Hydro will also generally be required to upgrade its facilities to allow the delivery of generation from the IPP, called "Network Upgrades". If the IPP has been awarded an Electricity Purchase Agreement under the Standing Offer Program, then BC Hydro provides a maximum contribution towards the costs of constructing the Network Upgrades and the customer is required to pay any costs over that contribution threshold. An IPP without an Energy Purchase Agreement with BC Hydro would generally pay for all the costs of the Network Upgrades.

BC Hydro is required to purchase non-firm energy under most IPP Electricity Purchase Agreements. As referenced in BC Hydro's response to BCUC IR 1.17.3, some of our Electricity Purchase Agreements, such as those offered under our Standing Offer Program, include mechanisms to limit energy purchase commitments through hourly or annual caps on eligible energy.

	F2017 Plan	F2018 Plan	F2019 Plan
Non-Firm Purchase Volumes (GWh)	5,329	5,695	5,804
Average Unit Cost ($/MWh)	57.9	59.6	63.9

As of May 1, 2016 for projects connected to or planned to connect to the integrated grid.

1.83.1 To what extent are the transmission and IPP interconnection projects covered by customer funding payment or BC Hydro investment?

RESPONSE:

We interpret the reference to "transmission" in the question to be transmission load customer and transmission IPP interconnection, and have structured our response accordingly.

Costs for Transmission Load Customers interconnections are allocated between BC Hydro and the load customer based on Tariff Supplement No. 6. Costs for IPP interconnections are either allocated between BC Hydro and the IPP based on the OATT, Attachment M and Attachment O, or on the rules of the Standing Offer Program if the generator connection is part of BC Hydro's Standing Offer Program.

The extent that the costs are borne by the customer or BC Hydro are customer and site specific, and vary on a case by case basis depending on the interconnection associated costs and the revenues BC Hydro expects to receive from the interconnecting entity.

153.1. What is the maximum contribution that BC Hydro provides towards the costs of Network Upgrades for IPPs?

153.2. Are the costs of Network Upgrades for which BC Hydro pays included in the cost of IPP energy?

153.3. What are the approximate costs of Network Upgrades provided by BC Hydro over the last ten year?

154. Reference: Exhibit B-10, CEC 1.69.2

1.69.2 Why are BC Hydro's F2017 Generation and Transmission Engineering expenditures approximately $1.7 million above F2016 Actual?

RESPONSE:

The $1.7 million increase from fiscal 2016 Actual to fiscal 2017 Plan is primarily due to a deliberate shift in the amount of time team leads and managers spend working on capital projects, instead dedicating more time to developing their teams in technical, leadership and Owner's Engineer skills. That work is not capitalized. As well, there was an increase of 13 FTEs from Workforce Optimization (the savings associated with Workforce Optimization are capital savings).

154.1. Please breakdown the $1.7 million into the value from the 13 FTEs and the shift from capital projects to team development.

154.2. What is the benefit from the deliberate shift to team development?

155. Reference: Exhibit B-10, CEC 1.73.1 and 1.73.2

1.73.1 Please briefly describe the two types of IPP energy that will be coming into service in F2018.

RESPONSE:

As described in section 5.7.8 of the Application, there are two IPP projects projected to come into service during fiscal 2017 (not fiscal 2018 as stated in the question above) that will be accounted for as capital leases. The table below provides details about these two projects.

Project Name	Fort St. James Green Energy	Merritt Green Energy
Type	Biomass	Biomass
Call Process	2010 Bio Energy Call Phase 2	2010 Bio Energy Call Phase 2
Capacity (MW)	40	40
Energy (GWh/year)	289	289

The Cost of Energy reflects the Total Payment to IPP after accounting adjustments, as described on page 4-23 of the Application, because both of these projects are categorized as capital leases.

Fort St. James Green Energy	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Total Payment to IPP	[redacted]	[redacted]	[redacted]
Accounting Adjustments	[redacted]	[redacted]	[redacted]
Cost of Energy	[redacted]	[redacted]	[redacted]

Merritt Green Energy	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Total Payment to IPP	[redacted]	[redacted]	[redacted]
Accounting Adjustments	[redacted]	[redacted]	[redacted]
Cost of Energy	[redacted]	[redacted]	[redacted]

The table below provides the corresponding forecast energy over the test period from each of the two Electricity Purchase Agreements.

Project	F2017 Plan (GWh)	F2018 Plan (GWh)	F2019 Plan (GWh)
Fort St. James Green Energy	[redacted]	[redacted]	[redacted]
Merritt Green Energy	[redacted]	[redacted]	[redacted]

155.1. Please confirm that these two IPP projects provide firm capacity and that wind and run of river projects do not.

155.2. Please confirm that these IPP projects are not dispatchable resources.

155.2.1. If not, please describe how much energy BC Hydro would be able to control.

156. Reference: Exhibit B-10, CEC 1.77.1 and CEC 1.77.2 and BCOAPO 1.36.2

The table below shows a breakdown of the $200.7 million reduction of capital expenditures, by expenditure type.

Expenditure Category	F2017 to F2019 Reductions to Capital Expenditures ($ million)
Growth	(29.5)
Redevelopment/Rehabilitation	(93.6)
Dam Safety	(102.8)
Sustaining	(9.9)
Portfolio Risk Adjustment	35.0
Total	(200.7)

1.77.2 Please provide a brief discussion of the types of expenditures that were included in the $17.3 million in planned capital addition reductions.

RESPONSE:

The table below shows a breakdown of the $17.3 million reduction of capital additions, by expenditure type.

Expenditure Category	F2017 to F2019 Reductions to Capital Additions ($ million)
Growth	(3.5)
Redevelopment/Rehabilitation	71.0
Dam Safety	(80.5)
Sustaining	(4.3)
Portfolio Risk Adjustment	0.0
Total	(17.3)

Generation Projects and Programs greater than $5 million that were part of the initial plan but were delayed or cancelled resulting in a reduction to capital expenditure or capital addition forecasts in the test period
$ million

A	B	C	D	E	F
#	Name of Project	Growth or Sustaining Expenditure	Delayed or Cancelled	Risk Score	Value Score
HYDROELECTRIC					
	Bridge River 1 Refurbish Penstocks 1 to 4 Exterior	1 - Sustaining	Delayed	10	
	Clowhom Rehabilitate Generating Station	3 - Redevelopment	Delayed	10	
	Elko Redevelopment	3 - Redevelopment	Delayed	9.5	
	John Hart Dam Seismic Upgrade	2 - Dam Safety	Delayed	11	
	Kootenay Canal Modernize Controls	1 - Sustaining	Delayed	10	
	Lake Buntzen 1 Coquitlam Tunnel Inlet Portal Seismic Upgrade	1 - Sustaining	Delayed	9	
	Peace Canyon Upgrade HVAC System	1 - Sustaining	Delayed	10	
	Strathcona Upgrade Dam Spillway	2 - Dam Safety	Delayed	11	
	Strathcona Upgrade Discharge	2 - Dam Safety	Delayed	11	
	Various Facilities Reduce Cutler Hammer Exciter Safety Risk Program	1 - Sustaining	Delayed	10	
THERMAL					
	Burrard Modify for Post Generation Operations	1 - Sustaining	Delayed	9	

156.1. How will the delays in dam safety impact future costs and revenue requirements?

156.1.1. Please explain and provide quantification where possible.

156.2. How will the delays in dam safety impact the benefits in dam safety investment?

156.2.1. Please explain and provide quantification where possible.

157. Reference: Exhibit B-1-1, Page 6-111 and 6-112, and B-10, CEC 1.79.1 and 1.93.1

During the fiscal 2017 to fiscal 2019 period, capital expenditures of $46.3 million are to maintain and upgrade capacity for data center compute, storage and networks to support continued growth and enhancements for applications and also to upgrade BC Hydro's personal computing assets and maintain print capabilities.

The Data Centre Refresh project will replace or upgrade the aging and end of life IT infrastructure in the primary data centre. The Windows Server upgrade project is well into implementation and will upgrade all servers to current versions. Data storage needs continue to grow rapidly driven by increasing IT use, new storage-intensive technologies, and changing records retention policies. Ongoing data centre expenditures include the sustainment of Windows and Unix servers.

The annual personal computer refresh program will continue, to enable the Windows update to version 10, allowing users access to current versions of Microsoft Office software.

1.79.1 Why were Cyber Security and Safety and current IT services considered a key priority?

RESPONSE:

Projects are prioritized based on value and risk reduction criteria. Cyber security threats pose a significant risk to BC Hydro and thus projects that address this risk have a relatively high value. Improving safety is a key business objective for BC Hydro and projects that address reducing safety risk to employees are valued relatively highly.

Maintaining current information technology services at existing performance levels is ranked highly as these are the basic information technology services required to support all of BC Hydro's business operations.

1.93.1 How old is the aging and end of life IT infrastructure in the primary data center?

RESPONSE:

The Information Technology Infrastructure at the primary data centre (Kamloops Internet Data Centre) is comprised of network, computing, and storage equipment. The majority of this equipment was purchased in 2012 and 2013 during the data centre move from Edmonds (Burnaby) to the Kamloops Internet Data Centre. Some of the equipment moved from Edmonds to Kamloops is older than 2012, with the remainder purchased later.

Network and computing equipment is generally refreshed every five to seven years and storage equipment every five years. As a result, many infrastructure assets at the Kamloops Internet Data Centre will be refreshed during the test period.

157.1. Could the aging and end of life IT infrastructure program be deferred? Please explain why or why not.

157.2. Please quantify the impact of deferring the aging and end of life IT infrastructure program by one year.

158. Reference: Exhibit B-10, CEC 1.86.4 and 1.89.2

1.86.4 What is the process by which the BCUC would become aware of any projects that were significantly over-budget and/or unsuccessful in meeting their objectives? Please explain.

RESPONSE:

BC Hydro believes that a revenue requirements process is a means whereby the British Columbia Utilities Commission and Interveners can obtain information and understanding of our capital plans and planning processes, including actual results for capital projects, compared to plan. In addition, BC Hydro includes information related to its capital plan in its Annual Report to the British Columbia Utilities Commission, including current year actual results compared to plan by business function (major asset category), planned capital expenditures for the following year, planned costs for capital projects with a total forecast cost greater than $5 million, and identification of capital projects that BC Hydro expects will be

subject to a Certificate of Public Convenience and Necessity or section 44.2 filing, in accordance with our Capital Project Filing Guidelines.

For projects that are the subject of a Certificate of Public Convenience and Necessity or a section 44.2 filing, BC Hydro provides periodic progress reports (quarterly, semi-annual and annual depending on the nature of the project) to the British Columbia Utilities Commission. These reports include project life-to-date actual results vs plan, forecast cost at completion, a discussion on variances between actual and forecast costs, as well as the identification and discussion of any issues that may impact project scope, cost or schedule. Final project reports, filed at the end of a project, include detailed variance analysis for actual versus forecast project costs, as well as a discussion on whether or not the project met its objectives.

We note that the Capital Expenditures and Projects Review proceeding currently in progress is expected to result in new British Columbia Utilities Commission-approved capital project filing guidelines.

For the Generation Portfolio, it was recognized that the Planned Expenditures for the portfolio as a whole have been higher than the Actual Expenditures in recent years. As our understanding of project and portfolio management has matured, the Portfolio Risk Adjustment was developed in an attempt to better predict how the expenditures are likely to change relative to planned expenditures over the test period.

158.1. Please identify any projects above a reasonable threshold level in the last 10 years which could be considered as over budget, and provide the year, the budget and the final cost.

159. Reference: Exhibit B-10, CEC 1.92.2

1.92.2 Please provide a brief discussion of the energy conservation tools being offered.

RESPONSE:

The customer energy management solutions included in the capital expenditures in the test period will provide customers with:

- Customized Home Energy Reports that compare similar homes in the customer's neighbourhood;
- Energy saving tips based on the physical characteristics of the customer's home and personal usage;
- Proactive notifications when unusual consumption is detected;
- Improvements to Team Power Smart challenges; and
- Product offerings based on products previously subscribed to or purchased by the customer.

159.1. Please provide the costs of the energy conservation tools being offered.

160. Reference: Exhibit B-10, CEC 1.92.4

1.92.4 Would BC Hydro anticipate failures from its web platform and call handling environment if capital investment were not performed at this time? Please explain.

RESPONSE:

The web platform and calling handling applications function well when the volume of transactions is normal to high. However, under extremely high volume conditions there is risk that some of the normal functionality will be stressed and system performance might degrade. This degradation may result in, but is not limited to, customers experiencing:

- Slow access to outage information on bchydro.com;
- Access problems related to current outage information; and
- Problems in reporting new outages to BC Hydro.

Modifications and enhancements to technology infrastructure are required to maintain system stability during these extremely high volume events.

160.1. What is the likelihood of BC Hydro experiencing 'extremely high volume events'?

160.2. What types of delays and reporting problems have customers experienced in the past that will be corrected with the investment in IT platforms? Please provide specifics and the expected improvements that would be achieved.

161. Reference: Exhibit B-10, CEC 1.93.2 and 1.119.5

1.93.2 What is the cost of the 'annual personal computer refresh program'?

RESPONSE:

The annual PC Refresh Program is a recurring capital expenditure to periodically replace obsolete personal computers for BC Hydro employees. Capital expenditures were $4.0 million in fiscal 2015, $3.1 million in fiscal 2016 and are expected to be $4.0 million in fiscal 2017, $3.0 million in fiscal 2018 and $3.0 million in fiscal 2019.

There is also an annual Operations PC Provisioning Program with expected annual capital expenditures of $1.0 million. This Program replaces lost or broken computers.

Year-over-year costs vary based on the number of units due for refresh in a given year, the average cost of the new devices, and the current US dollar exchange rate.

1.119.5 Please provide any cost/benefit analysis for projects over $5 million.

RESPONSE:

There are three programs with forecast capital expenditures over $5 million in the in the infrastructure category during the test period. The benefits for these programs are shown in the table below. These are future programs, and BC Hydro has not yet quantified their financial benefits.

Program	Benefits Description
Microsoft End User Devices License	• Reduced risk of non-compliance costs. • Reduced risk of loss of productivity due to out-of-date software.
PC Refresh	• Reduced risk of productivity loss due to older PCs, laptops, and tablets
Storage Capacity Growth	• Reduced risk of IT applications failing due to disk storage capacity constraints.

BC Hydro's response to CEC IR 1.119.3 provides a summary of all forecast capital expenditures during the test period.

161.1. Does BC Hydro have any evidence of productivity loss due to the use of older PCs, laptops and tablets that has occurred in the past?

161.1.1. If yes, please provide.

161.2. Could the annual PC refresh program be deferred? Please explain why or why not.

161.3. Please quantify the impact of deferring the annual PC Refresh program by one year.

162. Reference: Exhibit B-10, Fortis 1.4.2 and CEC 1.98.2 and 1.98.3

Reference: Exhibit B-1-1, Section 7.4, Page 7-16

BC Hydro believes that un-forecast and non-controllable expenditures with a net income impact of greater than $10 million in a fiscal year would be considered material; therefore, in these cases, a new regulatory account would be warranted to defer the impact for future recovery.

1.4.2 For those regulatory accounts where a number of items are recorded in one account, please confirm whether the $10 million materiality threshold is applied to the sum of all items or to each item considered for deferral.

RESPONSE:

Please refer to BC Hydro's response to FortisBC IR 1.4.3, in which BC Hydro notes that the $10 million figure referenced in the question from section 7.4 of the Application is in respect of new regulatory accounts.

In the event BC Hydro were proposing a new regulatory account comprised of a number of items, it would apply the $10 million figure against the total potential net income impact of the items comprising the proposed regulatory account, were it not approved. More specifically, if the total of the items comprising the proposed new regulatory account could have a net income impact of greater than $10 million, BC Hydro believes a new regulatory account is warranted if the other considerations outlined in section 7.4 are met.

1.98.2 Has BC Hydro used $10 million as a threshold previously?

RESPONSE:

BC Hydro's proposed $10 million threshold in respect of new regulatory accounts was included in its Regulatory Accounts Report, Appendix H to the Fiscal 2015 – Fiscal 2016 Revenue Requirements Rate Application.

BC Hydro had not proposed a threshold for this purpose previously.

1.98.3 Please provide the $ amount equivalent to a 1% rate increase.

RESPONSE:

The dollar amount equivalent of a one percent rate increase for fiscal 2017 is $43 million. This is calculated by dividing the total Revenue Subject to Rate Increase in Appendix A, Schedule 1.0, Line 28 by 100. This ignores the rate cap in place for fiscal 2017 for the purpose of answering the question.

162.1. What would be the ratepayer impact of changing the $10 million deferral account threshold to $5 million or increasing it to $20 million? Please explain and provide quantification where possible.

162.2. Is it possible that BC Hydro might have a number of potential accounts with a number of items for each account that would not trigger the $10 million threshold, but would do so in aggregate? Please explain.

163. Reference: Exhibit B-10, CEC 1.102.2

The performance metrics are:

	Participant 1	Participant 2	Participant 3	Participant 4
Capacity (MW)	65.0	22.0	22.0	17.0
Curtailment Events Passed	25	28	28	28
Curtailment Events Failed	2	0	0	0
Compliance Rate (by Event)	92.6%	100.0%	100.0%	100.0%
Number of 30 min Non-Compliance Intervals	12	0	0	0
Compliance Rate (by 30 min Interval)	97%	100%	100%	100%
Average KW's Below Contracted Capacity During Failures	42,973	NA	NA	NA
Maximum DR Provided (kW)	133,330	46,734	60,302	26,732
Maximum DR Provided (Ratio of Dispatched Capacity)	205.1%	212.4%	274.1%	157.2%
Average DR Provided (kW)	77,425	23,084	28,116	18,250
Average DR Provided (Ratio of Contracted Capacity)	119%	105%	128%	107%

There were some implementation issues which provided learning opportunities for BC Hydro and the participants. The most notable learning is the lack of ability to provide real-time customer performance feedback (i.e., metering). BC Hydro is only able to confirm the following day if the customer met the performance objectives. The other major issue related to the reference load from which the customer must reduce its load. With the complexity and variability of the customer's operations, it can be hard to find a large sample of "normal" operating days that are recent, especially when accounting for maintenance days.

Many issues were resolved with open communication between BC Hydro's team and the customer and included situations not anticipated by either side during the design and consultation period (i.e., is Boxing Day considered a statutory holiday?). These issues are being considered in Year Two.

163.1. What, if any, could the cost savings be if BC Hydro were to rely on Load Curtailment to meet capacity and energy demand in the test period?

163.2. Why is BC Hydro unable to provide metering allowing real-time customer performance feedback?

163.3. What would be the costs of providing such metering?

164. Reference: Exhibit B-9, BCUC 1.183.3

Table 1 Residential demand response ($ 000)

By Resource	F2015	F2016	F2017
Labour	97.9	106.3	172.0
Advertising	0	12.3	30.0
Consultants	85.7	270.9	1,881.0
Other non-labour	2.4	119.4	13.0
Incentives	0.3	64.4	100.0
Total	186.0	573.4	2,196.0

Table 2 Commercial demand response ($ 000)

By Resource	F2015	F2016	F2017
Labour	140.2	124.6	179.8
Advertising	0.9	0.8	10.0
Consultants	82.7	85.8	451.0
Other non-labour	0.4	8.1	9.0
Incentives	0	79.1	80.0
Total	224.1	298.3	729.8

Table 3 Industrial demand response ($ 000)

By Resource	F2015	F2016	F2017
Labour	65.9	83.8	211.6
Advertising	0	0	0
Consultants	54.8	70.1	50.0
Other non-labour	2.7	0	0
Incentives	8.1	83.6	0
Total	131.5	237.6	261.6

164.1. Please explain the requirement for $1.9 million in expenditures for consultants (F2017) for the Residential Demand Response program, and why it is so much higher than that required for Commercial or Industrial.

165. Reference: Exhibit B-10, CEC 1.108.3 and 108.4

108.0 Reference: Exhibit B-1-1, Page 10-11

BC Hydro has offered demand-side management programs to its customers since 1989. The BC Hydro Conservation and Energy Management team is composed of full time BC Hydro employees who have extensive experience in demand-side management delivery from design through implementation and evaluation.

1.108.3 What savings are yet to be achieved from the total dollar value of investment referenced above?

RESPONSE:

Please refer to the table presented in BC Hydro's response to CEC IR 1.108.4 for electricity savings yet to be achieved.

	Cumulative Electricity Savings (GWh/year) @ Customer Meter
F1989	22
F1990	63
F1991	222
F1992	595
F1993	968
F1994	1,371
F1995	1,713
F1996	1,968
F1997	2,262
F1998	2,448
F1999	2,470
F2000	2,478
F2001	2,459
F2002	2,561
F2003	2,757
F2004	3,071
F2005	3,534
F2006	3,992
F2007	4,249
F2008	4,686

	Cumulative Electricity Savings (GWh/year) @ Customer Meter
F2009	5,035
F2010	5,229
F2011	5,403
F2012	6,017
F2013	6,098
F2014	5,960
F2015	6,064
F2016	6,483
F2017	5,750
F2018	5,426
F2019	5,249
F2020	4,892
F2021	4,679
F2022	4,540
F2023	4,349
F2024	4,133
F2025	3,914
F2026	3,671
F2027	3,370
F2028	3,119
F2029	2,941
F2030	3,141

165.1. Please produce the same data for the future year by year investments.

165.2. Exhibit B-10, CEC 1.117.2

RESPONSE:

The new business processes and information technology to be implemented cover the full cycle of activities involved in acquiring materials and services. The scope of the Supply Chain Applications Project includes business processes covering forecasting and planning, procurement, contract management, inventory management and warehouse operations, and supplier payment.

The information technology to be implemented includes:

- SAP Materials Management: inventory management, forecasting and demand planning, material requirements planning, and warehouse operations for all materials;
- SAP Purchasing: purchasing processes, contract administration and invoice processing for all materials and services; and
- Integration – integration of SAP Supply Chain modules with other previously implemented SAP modules (project system, finance & controlling) and other systems, including PassPort (work management), Oracle Primavera Unifier Construction Contract Management, and Supply Chain Workspace (sourcing, category, and contract management).

The Supply Chain Applications Project is necessary because the existing information technology used to support BC Hydro's supply chain was implemented in 2003 at a time when BC Hydro's business operations and the demands on its supply chain were very different. There are a number of functions within its supply chain that BC Hydro is unable to execute effectively because of limitations with the existing technology. BC Hydro refers to these limitations as "capability gaps" and the Supply Chain Applications Project will address these gaps and achieve operational efficiencies, reduce material and service costs and provide an overall reduction in risk.

BC Hydro will make a determination on the timing of filing an application under section 44.2 of the *Utilities Commission Act* once the BC Hydro Inquiry of Expenditures Related to the Adoption of the SAP Platform is complete.

165.3. Please provide examples of the 'capability gaps' that BC Hydro experiences using its existing platforms.

165.4. Could the Supply Chain Applications Project be deferred? Please explain why or why not.

166. Reference: Exhibit B-10, CEC 1.116.1 and 1.116.4

1.116.1 Please provide a breakdown of the Customer planned expenditures by Project.

RESPONSE:

A breakdown of forecast capital expenditures by projects/programs planned in the test period in the customer category is provided in the table below. There are approximately 15 individual projects or programs forecast to be less than $1 million during the test period that are grouped together in the table.

Name of Project or Program ($ million)	F2017	F2018	F2019
Enterprise Billing Infrastructure	8.8	2.1	
Call Centre Long Term Telephony and IVR Foundation		4.0	0.2
Lodestar Replacement with SAP			3.0
Energy Insights	1.0	1.5	
Evolve Digital Channels		1.0	1.0
Customer Pay Now	1.7		
Web Platform Enhancements	1.9		
Outage – Automatic Notifications and Alerts		2.0	
Meter Tracking and Consolidation	0.7	0.8	
Projects and Programs (less than $1 million)	5.0	0.5	0.4
Total	19.1	11.9	4.6

1.116.4 Please provide any cost/benefit analysis for projects over $5 million.

RESPONSE:

Only the Enterprise Billing Infrastructure Project has forecast capital expenditures over $5 million in the customer category for the test period. BC Hydro's response to CEC IR 1.116.1 provides a summary of all forecast capital expenditures during the test period. The total forecast for this Project is $10.9 million in the test period.

The net financial benefits for this Project are not yet quantified. The expected benefits for the Project as defined in the Identification Phase business case include:

- Reduced cost of paper for bill and bill related content;
- Reduced cost of postage for bill delivery;
- Reduced customer service costs;
- Reduced risk of billing failure;
- Improved capability for content management on the bill;
- Increased paperless bill adoption; and

1.123.2 Please breakout the customer capital additions by major project.

RESPONSE:

The projects with total capital additions of greater than $1 million during the test period, for the customer category, are provided in the table below. Projects and programs with capital additions of less than $1 million in the test period are grouped together.

Name of Project or Program ($ million)	F2017	F2018	F2019
Enterprise Billing Infrastructure		16.2	
Call Centre Long Term Telephony and IVR Foundation		4.0	0.2
Loadstar Replacement with SAP			3.0
Energy Insights		2.5	
Evolve Digital Channels		1.0	1.0
Customer Pay Now	2.1		
Outage – Automatic Notifications and Alerts		2.0	
Meter Tracking and Consolidation		1.5	
Projects and Programs (less than $1 million)	8.0	0.4	0.4
Total	10.1	27.6	4.6

166.1. Could the Billing Enterprise project be deferred? Please explain why or why not.

166.1.1. If yes, for how long could the Billing Enterprise project be deferred?

166.1.1.1. Please quantify the cost savings and rate impact of each year's deferral.

166.1.1.2. Please quantify the benefits that would be deferred for each year's deferral.

167. Reference: Exhibit B-9, BCUC 1.66.1 page 3 of 4

Non-Financial Criteria Not Desirable

A number of information requests from the Commission suggest that non-financial public interest considerations may trigger the need for a CPCN application. BC Hydro believes that the addition of non-financial CPCN criteria would unnecessarily introduce significant uncertainty and regulatory inefficiencies with no appreciable benefit. A clear and unambiguous expenditure threshold is the only criteria that should be used to trigger a CPCN.

Financial thresholds have the benefit of being clear and unambiguous, making it easy for BC Hydro and stakeholders to determine which projects are subject to a CPCN requirement. Clarity is an important benefit as the requirement for a CPCN application can significantly change how BC Hydro manages its projects. For example, if a CPCN is required, BC Hydro will need to plan appropriately so that it can receive approval in a timely fashion without unduly delaying construction of the project. BC Hydro will also need to contract appropriately to ensure that construction does not commence prior to a CPCN being received and to ensure that all commitments are subject to Commission approval. It is therefore important that BC Hydro be able determine in advance whether a CPCN is required.

BC Hydro considers that to some degree, all projects have public interest issues that are similar. Non-financial criteria, however, are by their nature subjective and ambiguous. For example, a non-financial criterion may be that a CPCN is required if there are significant stakeholder concerns raised with respect to a project. It is not possible to objectively determine if concerns raised are significant or not. Further, the nature of stakeholder concerns may not be apparent until late in the project lifecycle.

167.1. Please confirm or otherwise explain that BC Hydro from time to time internally justifies projects based on non-financial criteria.

167.2. If the criteria were an unambiguous expenditure threshold and/or a significant public interest issue, would BC Hydro object? Please explain.

168. Reference: Exhibit B-10, AMPC 1.7.1

Forecast of Percentage of Residential Accounts with Electric H

	Single Family Dwelling Duplex	Row	Apartment	Other
F2017	29.1%	53.8%	65.1%	2.5%
F2018	29.0%	53.7%	65.0%	2.5%
F2019	29.0%	53.7%	65.0%	2.5%
F2020	28.9%	53.8%	65.1%	2.5%
F2021	28.9%	53.8%	65.2%	2.4%
F2022	28.9%	53.9%	65.3%	2.4%
F2023	28.9%	53.9%	65.3%	2.4%
F2024	28.8%	53.8%	65.3%	2.3%
F2025	28.8%	53.8%	65.2%	2.3%
F2026	28.7%	53.7%	65.0%	2.3%
F2027	28.7%	53.7%	64.9%	2.3%
F2028	28.6%	53.7%	64.8%	2.2%
F2029	28.6%	53.6%	64.8%	2.2%
F2030	28.5%	53.6%	64.7%	2.2%
F2031	28.5%	53.6%	64.7%	2.2%
F2032	28.4%	53.5%	64.6%	2.2%
F2033	28.4%	53.5%	64.5%	2.1%
F2034	28.3%	53.4%	64.5%	2.1%
F2035	28.2%	53.4%	64.4%	2.1%
F2036	28.2%	53.3%	64.4%	2.1%

168.1. Why is the penetration rate for electric heating expected to decline for all dwelling types over the next two decades? Please provide the rationale and any evidence that BC Hydro has to support these assumptions.

169. Reference: Exhibit B-10, AMPC 1.14.2

1.14.2 Please contrast the cost of energy under the SOP against the assumed marginal cost of DSM in each major DSM category, such as Rates, Codes and Standards, and Programs.

RESPONSE:

BC Hydro understands that this information request is seeking to compare the Standing Offer Program cost of energy to BC Hydro's Demand-Side Management Programs. This is not an applicable comparison because the Standing Offer Program is a requirement pursuant to subsection 15(2) of *the Clean Energy Act*, and as stipulated by the 2007 Energy Plan, the contract price offered is based on BC Hydro's most recent BC Hydro call for power.

We provide the following additional information to be responsive to the information which is being requested. Currently, the Standing Offer Program price

ranges from $102/MWh to $112/MWh (fiscal 2016$) depending on the region of the Point of Interconnection and as set out in the Standing Offer Program Rules[1]. In addition, BC Hydro is currently undertaking a review of the Standing Offer Program price and structure to reflect system needs and recent advancements in technology and to align with the 10-year Rates Plan.

With respect to the information requested on demand-side management, BC Hydro interprets the term "assumed marginal cost of DSM" to mean the "long-run marginal cost" which is described in Section 3.4.4 of the Application. For more information on how BC Hydro uses the long-run marginal cost to measure cost-effectiveness in the context of Demand-Side Management Programs, please refer to BC Hydro's response to BCSEA IR 1.3.2.

169.1. Is the $102/MWh to $112/MWh price range the prices delivered to a particular location or the prices at plant gate? Please explain.

169.2. If the prices are not delivered prices, please provide the price range as delivered to the lower mainland.

170. Reference: Clean Energy Act, Section 15

Standing offer program

15 (1) In this section:

"eligible facility" means a generation facility that

(a) either

(i) has only one generator and the generator's nameplate capacity is less than or equal to the maximum nameplate capacity or has more than one generator and the total nameplate capacity of all of them is a capacity less than or equal to the maximum nameplate capacity, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities;

"maximum nameplate capacity" means 10 megawatts or, if another capacity is prescribed for the purposes of this section, the prescribed capacity.

(2) The authority must establish and, except in the prescribed circumstances, maintain a standing offer program to acquire electricity from eligible facilities.

(3) The authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions on which offers under the standing offer program under subsection (2) are to be made.

170.1. Does BC Hydro have a minimum quantity of energy it must acquire from the standing offer program?

170.1.1. If yes, please provide.

170.2. Please confirm that BC Hydro has discretion to establish the terms and conditions under which the standing offer program is offered.

170.2.1. If not confirmed, please explain why not and identify the limitations that BC Hydro must adhere to in developing its offer.

170.3. Please discuss the terms and conditions that BC Hydro relies on to ensure the cost-effectiveness of the energy it acquires through the standing offer program.

171. Reference: Exhibit B-10, AMPC 1.14.4

1.14.4 Please summarize the quality of the energy obtained under the SOP compared to DSM by major DSM category, in terms of firmness, dispatchability, curtailability, capacity value, and green attributes.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 1.14.2 for a description of why BC Hydro believes that the Standing Offer Program is not an applicable option for comparison to other options to meet incremental need, such as Demand-Side Management.

However, to be responsive, we provide the following additional information.

In terms of energy quality, BC Hydro considers "firmness, dispatchability, curtailability, capacity value and green attributes" to be supply-side characteristics associated with a generating resource. Whereas, demand-side management initiatives impact load rather than provide supply to meet load. This distinction is important because BC Hydro plans for meeting system needs by adjusting its load forecast to reflect the expected impact of demand-side management initiatives (i.e., the P50 estimate). The stack of available supply-side resources is then used to meet the resultant ("after DSM") load forecast.

For demand-side management initiatives, customers make changes to their behaviour or install new energy efficient measures in response to our initiatives (e.g., by installing a new energy efficient appliance) which is expected to result in energy savings. Because the energy savings are a reduction of the load, the energy savings follow the same characteristics of the load that it has reduced (i.e., the "quality" of the load reductions is the same as the load itself). BC Hydro performs uncertainty analysis to understand and plan for different levels of demand-side management savings, including different levels of participation in its initiatives. Please refer to BC Hydro's response to BCSEA IR 1.35.1 for a discussion of how specific demand side management initiatives impact greenhouse gas emissions.

In contrast, the Standing Offer Program is an acquisition program for energy from clean or renewable supply-side resources that have the following "qualities":

- Firm energy, using a planning view of BC Hydro's load resource balance and based on BC Hydro's assessment of firm energy load carrying capability;
- Curtailability of generation through a provision in the Standing Offer Program standard form Electricity Purchase Agreement that allows BC Hydro to request an IPP to reduce or cease energy deliveries for specified periods;
- Capacity to meet winter peak loads, as provided in Table 3-9 of the Application and based on BC Hydro's assessment of effective load carrying capability; and
- Environmental attributes through program rules requiring generation to be from a clean or renewable resource and through contract provisions that transfer ownership of any environmental attributes associated with energy deliveries to BC Hydro from the IPP to BC Hydro.

1.14.3 Please provide (a) the types of generation resources assumed to make future SOP volumes (e.g. wind, micro-hydro, solar, etc.); and (b) the analysis and summary of the expected mix of projects (i.e., number of projects and percent of expected delivered energy) for SOP deliveries to BC Hydro by generation type.

RESPONSE:

The table below provides the types of generation resources and the relative proportions of energy delivery volumes expected for the mix of projects for the Standing Offer Program volumes. These percentages are based on the portfolio of awarded Electricity Purchase Agreements and the portfolio of active applications under the Standing Offer Program (as of March 1, 2015) which is the data set used for the Application. However, the Standing Offer Program is not prescriptive about the resource mix and the data set used for the Application may not reflect the mix of resource types for future Electricity Purchase Agreements.

As discussed in BC Hydro's response to BCUC IR 1.17.4, the number of expected agreements to be executed is unknown as our forecasts are based on volumes and not number of agreements.

Resource Type	Per Cent (Forecast Volume) of the Standing Offer Program
Non-Storage Hydro	54.3
Wind	35.5
Biogas	5.4
Biomass	2.9
Storage Hydro	1.5
Waste	0.1
Solar	0.2

171.1. How does BC Hydro assess firm energy load carrying capability?

171.2. Please provide a discussion the types of terms that BC Hydro uses to curtail energy. Are there limits to the curtailability that BC Hydro can request or does BC Hydro have full control? Please explain.

171.3. Please confirm or otherwise explain that there is no need for 'curtailability' with respect to DSM.

171.4. Please confirm or otherwise explain that because DSM follows the same characteristics of the load that it reduces, it may be considered as contributing to peak reduction.

171.5. How does BC Hydro assess capacity to meet winter peak loads, and 'effective load carrying capability' with respect to winter peak? Please explain.

171.6. Please complete the following table, using Yes and No responses or brief descriptions where applicable.

	Firm (%)	Non-Firm (%)	Curtailability	Capacity to meet Winter Peak loads	Cost Range in Existing Resource Stack delivered to Lower Mainland	Dispatchability
Non-Storage Hydro						
Wind						
Bio-gas						
Storage Hydro						
Waste						
Solar						
Other (Define)						

172. Reference: Exhibit B-10, AMPC 1.14.5

1.14.5 Please summarize (a) the green and clean attributes required of SOP suppliers and (b) ownership provisions of any green attributes for energy procured under the SOP.

RESPONSE:

Energy delivered to BC Hydro under a Standing Offer Program Electricity Purchase Agreement must be generated from a Clean or Renewable Resource. A "Clean or Renewable Resource" is as defined by the *Clean Energy Act* and regulations as: biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any biogenic waste, waste heat and any additional prescribed resources.

All environmental attributes for the energy delivered to BC Hydro under the Energy Purchase Agreement are transferred to BC Hydro in accordance with the terms of the Energy Purchase Agreement. The value of the environmental attributes is embedded in the price paid for energy delivered.

172.1. Please confirm that BC Hydro can have discretion on the types of clean or renewable resources that BC Hydro purchases under the Standing Offer Program.

173. Reference: Exhibit B-10, AMPC 1.14.6

1.14.6 Please summarize other attributes of the energy obtained under the SOP compared to marginal DSM in terms of economic benefits, e.g. GDP, employment, benefits to local communities, and benefits to Local First Nations.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 1.14.2 for a description of why BC Hydro believes that the Standing Offer Program is not an applicable option for comparison to other options to meet incremental need, such as Demand-Side Management.

However, we also provide the following information to be responsive. The attributes requested in the question is not data collected by BC Hydro in relation to the Standing Offer Program, and is information that would be difficult to quantify. As such, we do not have this information but note the following.

The Standing Offer Program projects are small (under 15 MW), geographically diverse, and can be owned and operated locally. Accordingly, it is likely that they could provide additional employment and other related local economic benefits – particularly if these projects are located in more remote locations and/or First Nations communities. For a summary of the additional benefits provided by Demand-Side Management initiatives, please refer to BC Hydro's response to BCUC IR 1.185.1.

173.1. Please confirm that IPP projects are free to sell their energy to market if it is not purchased under the Standing Offer Program.

174. Reference: Exhibit B-10, AMPC 1.15.3

1.15.3 Please provide the key assumptions used with respect to future IPP deliveries (including renewals) in the load resource balance base for both low and high scenarios.

RESPONSE:

BC Hydro understands the reference to the 'load resource balance base for both low and high scenarios' in the question above to mean the 'Small Gap' and 'Large Gap' scenarios described on page 3-37 in section 3.4.2 of the Application and presented in Table 3-8 and Table 3-9 of the Application.

The assumptions with respect to future IPP deliveries (including renewals) in the load resource balances provided in section 3.4.2 of the Application are the same for the base case and the 'Small Gap' and 'Large Gap' scenarios.

In the base case we use the existing and committed supply contracted under Electricity Purchase Agreements with IPPs plus the future expected commitments under the Standing Offer Program and the forecast volumes from IPP Electricity Purchase Agreement renewals. As described in section 3.4.3.5 of the Application, on pages 3-42 and 3-43 and consistent with the 2013 Integrated Resource Plan, we assume renewal of 50 per cent of the energy and capacity volumes from biomass Electricity Purchase Agreements and 75 per cent of the energy and capacity volumes from the run-of-river hydroelectric Electricity Purchase Agreements that are due to expire within the remaining years of the 2013 10 Year Rates Plan.

174.1. Please provide BC Hydro's rationale for its renewal assumptions.

175. Reference: Exhibit B-1-1, Page 3-30, Table 3-8

Evaluation of the Appropriateness of Early Acquisition of Power

Discount Rate	7%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Quantity	1000 GWh																																												
Sale Value	27 $/MWh																																												
Surplus Profile	GWh	4945	4928	3524	5654	4351	2505	1416	881	3608	4113	3534	2748	1959	1117	278	-662	-1355	-2118	-2704	-4056																						
Purchase Price	107 $/MWh																																												
Purchase	$ million	80	80	80	80	80	80	80	107	80	80	80	80	80	80	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107
PV of Purchase	$1,206 $ million																																												
Future Purchase	$ million	0	0	0	0	0	0	0	0	0	0	0	0	0	0	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107
PV of Future Purchase	$491 $ million																																												
Benefit of Delay	$715 $ million																																												
Future Purchase Breakeven	$ million	0	0	0	0	0	0	0	0	0	0	0	0	0	0	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263
Future Purchase Price for Breakeven	263 $ million																																												
PV Breakeven Future Price	$1,206 $ million																																												
Breakeven Benefit	($0) $ million																																												
Renewal Purchase Price	75 $/MWh																																												
Renewal	$ million	48	48	48	48	48	48	48	75	48	48	48	48	48	48	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
PV of Purchase	$779 $ million																																												
Future Purchase	$ million	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
PV of Future Purchase	$344 $ million																																												
Benefit of Delay	$435 $ million																																												

175.1. The CEC has calculated above the Present Value cost to the ratepayer of acquiring energy in advance of the need for energy and found that for 1,000 GWh of delayed purchase the ratepayer would benefit by approximately $700 million. Also, the CEC has calculated that a future purchase in real dollar terms would need to be $263/MWh versus $107/MWh to breakeven for an early purchase. This represents a real value increase in renewable energy supply of 146%. The CEC's understanding is that renewable energy in real dollar terms is declining not increasing. The CEC realizes this is a proxy calculation and can be made more sophisticated for actual circumstances, but believes it is indicative of the policy issues.

Please provide BC Hydro's own analysis, as prepared before it has made its decisions in regard to its load resource balance evidence, of the benefits or costs of purchasing energy before it is needed, and provide its views with respect to how it is benefiting ratepayers.