REQUESTOR NAME: **Clean Energy Association of B.C. (CEBC)**

INFORMATION REQUEST ROUND NO: **2**

TO: **BRITISH COLUMBIA HYDRO & POWER AUTHORITY**

DATE: December 16, 2016

PROJECT NO: 3698869 / Order G-40-16

APPLICATION NAME: **F2017-F2019 Revenue Requirements Application ("F17-19 RRA" or "RRA")**

25.0 **Reference: BC Hydro public statement re the roll of the RRA process in reviewing the 20-year load forecast**

On November 17, 2016, BC Hydro Media Relations wrote the following response to a news article published in the Alaska Highway News:

Independent Site C poll flawed, BC Hydro says

Alaska Highway News published November 17, 2016 01:03 PM

(Re :'A tale of two Site C polls,' Alaska Highway News, Nov. 16, 2016)

http://www.alaskahighwaynews.ca/opinion/letters/independent-site-c-poll-flawed-bc-hydro-says-1.2882121#sthash.1nEvRvgF.dpuf

25.1 In paragraph 2 of this response, BC Hydro states that,"*In fact this is already happening. The BC Utilities Commission is currently conducting a public process to review BC Hydro's Revenue Requirements Application which includes our 20-year load forecast."* Please confirm that BC Hydro's position is that an examination of the entire 20 years of the load forecast is within the scope of this RRA proceeding.

26.0 **Reference: Exhibit B-10, BC Hydro's response to CEBC IR 1.3.3, Rate Smoothing**

In its IR response, BC Hydro includes the following table showing the annual additions/recoveries to the Rate Smoothing Regulatory Account between F2017 and F2024.

Rate Smoothing

$ million	F2017 Plan	F2018 Plan	F2019 Plan	F2020 Forecast	F2021 Forecast	F2022 Forecast	F2023 Forecast	F2024 Forecast
Beginning of Year	287.4	497.4	783.3	1,082.7	1,490.7	1,589.4	1,285.8	732.5
Additions/(Recovery)	210.0	285.9	299.4	408.0	98.7	(303.6)	(553.3)	(732.5)
Interest	-	-	-	-	-	-	-	-
End of Year	497.4	783.3	1,082.7	1,490.7	1,589.4	1,285.8	732.5	-

26.1 Even though the balance in this account is rising from $500 million to $1.6 billion over a 4 year period, the table shows that no interest is being accrued against this balance. Please explain whether, and to what extent BC Hydro's debt will be increasing as a result of the rising balance in this regulatory account?

26.2 Please explain why this account will not incur interest charges.

27.0 **Reference: Exhibit B-10, BC Hydro's response to CEBC IR 1.3.4, Rate Smoothing; and the Minister's letter to BC Hydro, November 3, 2016, given as Attachment 1 to BC Hydro's response to BCUC IR 1.7.2 (in Exhibit B-9)**

In its response to CEBC 1.3.4, BC Hydro states that:

> *BC Hydro has taken a number of actions to reduce forecast costs over the period covered by the 2013 10 Year Rates Plan (i.e., fiscal 2015 through fiscal 2024),*
>
> *including the following:*
>
> - *Reducing forecast capital expenditures and capital additions;*
> - *Employing a debt management strategy, and reducing forecast finance charges;*
> - *Implementing operating cost savings in order to limit forecast base operating increases to an average of 1.2 per cent per year; and*
> - *Targeting renewal of expiring Independent Power Producer contracts at less than what they are currently paid.*
>
> *The above actions persist beyond the test period.*
>
> *Additionally, the Government is also making significant changes to reduce pressure on BC Hydro's rates, such as the planned elimination of Tier 3 water rental rates in fiscal 2018, changing the calculation of BC Hydro's return on equity, and reducing BC Hydro's dividend payment.*

In the Minister's letter (Attachment 1 to BCUC 1.7.2), the Minister outlines the steps taken by the government *"to keep the Rates Plan on track. The Province has: directed the BC Utilities Commission (BCUC) with respect to rates for the first 5 years of the Rates Plan; decoupled net income from assets in service; removed the Tier 3 water rental rate; and more recently established lower dividends and net income targets than initially anticipated in the Rates Plan and as provided for under existing regulations."*

The Minister also outlines the steps taken by BC Hydro: *"BC Hydro has undertaken extensive cost reduction actions... These actions have included: reducing growth in operating costs; hedging interest rates; restructuring demand side management programming; adjusting capital additions and dismantling costs; and reducing power procurement and energy supply contract renewal costs."*

27.1 With regard to the BC Hydro cost reduction actions, please provide a table showing the dollar impact on the total Revenue Requirements over each year of the 10 Year Rates Plan (F2015 to F2024) due to each of the following BC Hydro actions:

- Reducing growth in operating costs
- Hedging interest rates
- Employing a debt management strategy, and reducing forecast finance charges
- Adjusting capital additions and dismantling costs
- Reducing power procurement and energy supply contract renewal costs.

27.2 Please explain what measures BC Hydro is using to reduce its forecast finance charges, and what is the expected impact of each of these measures on the annual Revenue Requirements over each year of the 10 Year Rates Plan (F2015 to F2024).

27.3 Please explain what would be the impact on the annual Revenue Requirements over each year of the 10 Year Rates Plan (F2015 to F2024) due to an increase in the interest rates on BC Hydro's debt of 0.50% for F2018, followed by a further increase of 0.50% for F2019 and subsequent years (i.e. 1.0% higher interest rates for F2019 through F2024). In that case would BC Hydro be able to meet the rate increase caps prescribed in the Rates Plan, and how would this be achieved?

27.4 With regard to the government's cost reduction actions outlined in the Minister's letter, please provide a similar table showing the dollar impact on the total Revenue Requirements over each year of the 10 Year Rates Plan (F2015 to F2024) due to each of the following government actions:

- Directing the BCUC with respect to rates for the first 5 years of the Rates Plan
- Decoupling net income from assets in service
- Reducing the annual obligations of BC Hydro to pay dividends to the Province
- Removing the Tier 3 water rental rate
- Establishing lower dividend and net income targets than initially anticipated in the Rates Plan.

28.0 Reference: Exhibit B-1-1, Application, Table 1-6, p. 1-37, Revenue Requirements - Gross View, and Appendix A, Schedule 1, Revenue Requirements Summary

28.1 Using the Gross View data in Schedule 1, please provide a working Excel model showing a tabular summary of the history of BC Hydro's Revenue Requirements since F2007. Show the "Actual" values from F2007 through F2016 and the "Plan" values for F2017 to F2019. To reduce the lines in the table, condense the rows to the following:

- Cost of Energy,
- Operating Costs,
- Capital Charges (including Amortization, Finance Charges, and Return on Equity),
- Taxes and Other (including Non-Tariff, Inter-Segment, Subsidiaries, Other Utilities)
- Deferral Account Transfers
- Regulatory Account Transfers (but excluding the Rate Smoothing Regulatory Account)
- **Total Revenue Requirements before Deferral Rider and Rate Smoothing**
- Deferral Rider
- Rate Smoothing
- **Total Revenue Requirements after Deferral Rider and Rate Smoothing**

29.0 Reference: Exhibit B-1-1, Application, p. 3-6, and Exhibit B-10, response to CEBC IR 1.5.2, Residential load forecast

In the Application, page 3-6, BC Hydro states, *"Electricity sales to this sector tend to be relatively steady as they are driven by population growth and general economic trends. Any large fluctuations in sales from year to year are mainly due to weather. The residential sales forecast is prepared on a temperature normalized basis; normal temperature is defined as a ten-year rolling average of monthly heating and cooling degree days.... BC Hydro notes that FortisBC Electric also uses a ten-year rolling average in their electricity Load Forecast."*

29.1 IR 1.5.2 may not have been clearly stated. Presumably BC Hydro's sales to Fortis are based on Fortis's forecast of its expected residential sales. So the question is why can Fortis accurately forecast its residential sales in F2015 (within 1%), but BC Hydro's residential forecast was 10% too high, when both are using a temperature normalized method. Then, in F2014, the reverse was the case: the FortisBC forecast was overestimated by 100% while the BC Hydro residential forecast was within 1%. What is different between the two companies forecasting methods for their residential loads?

30.0 Reference: Exhibit B-10, response to CEBC IR 1.5.3, Residential load forecast

The question asked for the residential use per customer account to be temperature normalized and broken down by region, heating type and by dwelling type. Since single family residences typically use significantly more electricity than multi-unit dwellings, it's important to segregate these two dwelling types.

30.1 Does BC Hydro have the data on use per account broken down by dwelling type? If so, please provide the table as requested, in a working Excel model.

30.2 If not, can BC Hydro please provide the data on the number of each dwelling type by region over the period since F2011?

31.0 Reference: Exhibit B-10, response to CEBC IR 1.6.1, Energy Sales Forecast, and Exhibit B-1-1, the Application, Appendix A, Schedule 14, and BC Hydro's Annual Report and Service Plan for 2015/2016

BC Hydro's response indicated that the amounts for total Domestic Energy Sales (GWh) on line 10 of Schedule 14 are the values after DSM savings have been applied. The amounts on line 10 include Residential, Light Industrial and Commercial, Large Industrial, and a number of "other" minor sales such as Irrigation, Street Lighting, Fortis, etc. However, when looking back at the history in Schedule 14, the total of these "other" loads is sometimes quite different from that captioned as "Other" in BC Hydro's Annual Report. For instance, in F2016, the other sales shown in Schedule 14 are only 1,602 GWh, whereas the "Other" sales shown in the Annual Report are 7,879 GWh. Again in F2013, Schedule 14 shows 1,397 GWh, while the Annual Report shows 7,417 GWh. The difference varies from year to year, but in some years it is quite significant, 6,000 GWh or more.

31.1 What is responsible for the differences between the Schedule 14 values for other sales and the Annual Report values captioned as "Other"? And why are these different amounts not included in the Revenue Requirements Schedule 14?

31.2 Has the use of the term "Other" in the Annual Service Plan Report and its predecessor Annual Reports been the same for the last 10 years. If not please explain the difference in use. Please explain the wide variation in the annual volume of gigawatt-hours recorded as "Other" in the Annual Service Plan Report and its predecessor Annual Reports over the last ten years.

31.3 Please provide a table (and a working Excel model) reconciling the differences between the total Domestic Electricity Sales (GWh) shown in the Annual Reports and the Total on line 10 of Appendix A, Schedule 14, for the period shown in Schedule 14, which covers the actual results from F2007 to F2016, and forecast amounts forward through the test period to include F2019.

32.0 Reference: Exhibit B-10, response to CEBC IR 1.7.1, Residential Energy Sales Forecast

BC Hydro's response indicates that the compound growth rates for residential sales in Section 3.2.1 of the Application have been shown for a 5-year period, a 10-year period, and a 19-year period. By CEBC's estimation, this will mean that the rate of increase for the first 5 years will be approximately 1.9% per annum. Then for the years 6 to 10, the rate of increase will rise to approximately 2.3% per annum, and for years 11 to 19 the rate will drop off significantly to only 1.7% per annum.

32.1 Please confirm that the rates of increase calculated by CEBC for the three periods are approximately correct based on the forecasts given in the Application, Section 3.2.1.

32.2 Please explain why BC Hydro believes the rate of increase will jump significantly for the middle period of 5 years (years 6 to 10) and then fall off significantly for the final 9 years. What is responsible for the significant jump expected in the middle years and the falloff in the latter years?

33.0 Reference: Exhibit B-10, response to CEBC IR 1.9.1 to 1.9.3, the role of DSM in advancing Climate Leadership Plan goals through electrification

BC Hydro's response to CEBC 1.9.1 indicates that it does view the use of demand side measures to help achieve climate leadership goals as a totally consistent purpose for those measures. It stated, *"Our view is that helping our customers with energy management solutions that include the reduction of greenhouse gas emissions by using clean electricity in place of other forms of energy such as gasoline, natural gas and diesel is consistent with our definition of demand-side management..."* This would include both new loads whose base case would be using non-clean fuels, and existing loads that could be converted from non-clean fuels.

In its response to CEBC 1.9.2 BC Hydro outlined work on low-carbon electrification to date, which included:

- development of an initial inventory or low-carbon electrification end-uses;
- working with government and industry to fulfill the Climate Leadership Plan;
- scanning electrification programs in other jurisdictions;
- considering how to expand DSM programs to support low-carbon electrification.

In its response to CEBC 1.9.3 BC Hydro agreed that electric vehicles and heat pumps were opportunities that had been included in the low-carbon inventory of end-uses for potential electrification and would further explore a role for DSM programs in advancing their adoption.

33.1 Can BC Hydro please provide more detailed information about its initial inventory of end-uses? What low-carbon electrification end-uses has it included in its initial inventory? What existing loads and what new loads is BC Hydro considering for electrification? What does BC Hydro consider to be the potential electrification amounts for each of these end uses and what amounts of GHG emissions can be eliminated?

33.2 Please provide more detail on what measures are being pursued to encourage electric vehicles and heat pumps. What proposals have been made to senior management or the Board, and what approvals have been given?

33.3 Is the Climate Leadership Plan released by the government in August, 2016 on the record in this proceeding? If not, can BC Hydro please place it on the record?

34.0 Reference: Exhibit B-10, response to CEBC IR 1.9.4, Advancing electrification in northeast oil and gas fields, and Exhibit B-1-1, Application, Appendix G, Board briefing - BC Hydro 10 Year Capital Forecast Update (July 2016)

In its response, BC Hydro quotes from the Climate Leadership Plan:

"Capital funding will be necessary to develop upstream electrification of several key projects: Peace Region Electricity Supply Project; North Montney Power Supply Project; and Other upstream electrification infrastructure.

Electrification of natural gas developments in the Montney formation in Northeast B.C. is currently proceeding with existing infrastructure to avoid GHG emissions by up to an estimated 1.6 million tonnes per year. Full electrification of the Montney Basin could avoid up to 4 million tonnes of emissions per

*year, minimizing the GHG footprint of upstream natural gas development to ensure that B.C. has th*e *cleanest LNG in the world*."

34.1 The Climate Leadership Plan identifies two specific Northeast transmission projects: the Peace Region Electricity Supply Project, and the North Montney Power Supply Project, plus other electrification infrastructure. Are these projects in the present capital plan as it was described in the Board briefing note of July 2016 - BC Hydro 10 Year Capital Forecast Update (July 2016)? The first appears to be in the list in Attachment #2 but the 2nd doesn't seem to appear by that name.

34.2 If these two major transmission projects are considered necessary in order to electrify the Montney region, what priority have they been given, and what are the amounts of capital are being budgeted for these two projects in the context of the 10 Year Capital Forecast? When does BC Hydro think it is feasible to have these two projects in service.

34.3 Please provide the full details for the calculations of 1.6 and 4 million tonnes per year including raw gas production, electrical intensity factors for well drilling, fracking, transport of gas from the wellhead to the gas processing plant, gas processing plant, compression to market gas pipeline standard, any probabilities used in the evaluations, and other information provided by gas producers to key account managers used in the evaluations.

34.4 What would the emissions be in tonnes per year if no electricity was used for natural gas development in the Montney assuming the same volumes of raw gas production as for full electrification?

34.5 Would full electrification reduce GHG emissions by approximately 75% as compared to no electrification?

34.6 Does BC Hydro agree that the saving of 1.6 million tonnes of GHG emissions per year by electrification will require approximately 3,000 GWh of new electricity? If not, what amount does BC Hydro calculate? Within what time frame is BC Hydro intending to have this amount of new electricity available, and how does it plan to generate it?

34.7 Does BC Hydro also agree that the saving of 4 million tonnes of GHG emissions per year by electrification will require approximately 8,000 GWh of new electricity? If not, what amount does BC Hydro calculate? Within what time frame is BC Hydro intending to have this amount of new electricity available, and how does it plan to generate it?

35.0 Reference: Exhibit B-10, response to CEBC IR 1.9.4, Advancing electrification in northeast oil and gas fields, and recent news release from the Minister

The following statement by the Energy Minister was reported December 1, 2016:

"BC Hydro to offer incentives to oil and gas companies to go electric: Bennett

December 1, 2016 Chris Newton News, Regional

http://energeticcity.ca/2016/12/bc-hydro-offer-incentives-oil-gas-companies-go-electric-bennett/

FORT ST. JOHN, B.C. – *The B.C. Ministry of Energy and Mines is hoping that an aggressive new plan will see more oil and gas companies operating in the Peace Region to switch to using electricity to run some of their key equipment.*

Energy Minister Bill Bennett says that many companies are using natural gas to run their gas processing

equipment, because it is currently cheaper than using electricity from BC Hydro's grid. According to Bennett, BC Hydro is proposing to offer cash rebates to these oil and gas companies to be used towards the purchase of new electric-powered natural gas processing equipment. In return, Bennett says that these companies would then sign contracts with Hydro to purchase power from them at the same industrial rate that pulp mills, mines, and other users currently pay. He says that the switch to using electricity from BC Hydro's grid would greatly reduce greenhouse gas emissions and would also be cost-effective in the long term."

35.1 Can BC Hydro please give the full details of this proposal to offer incentives to oil and gas operators to electrify?

35.2 When will these incentives be in place and what will be the anticipated impact on the demand for electrical services in the area?

35.3 How and how quickly will BC Hydro be able to serve this additional load?

36.0 **Reference: Exhibit B-10, response to CEBC IR 1.11.1 re Generation Growth Capital Planning, and Exhibit B-1-1, the Application, Appendix G, 10 Year Capital Forecast Update (July 2016)**

In its response to CEBC IR 1.11.1, BC Hydro gave the following summary table of the 12-year total of its capital spending from F2015 to F2026 (excluding Site C), broken down by business segment and expenditure category:

($ millions)	Generation	Transmission	Distribution	Support Services	Total
Growth	718.0	3,274.1	1,800.0	33.4	5,825.5
Redevelopment	1,382.4				1,382.4
Dam Safety	1,610.8				1,610.8
Sustaining	2,723.7	3,673.0	2,475.2	2,129.6	11,001.5
Total	6,434.9	6,947.1	4,275.2	2,163.0	19,820.2

Since Site C is excluded from the Generation Growth category, the only remaining projects in that category are Revelstoke 6, Revelstoke Switch Gear, and GMS upgrades to units 1-5, none of which produce significant amounts of new energy. However, $5 billion has been identified as "Growth" projects in Transmission and Distribution.

36.1 Since, after DSM, there is very little new customer load showing in the May 2016 updated Load Forecast, and since the only new energy is coming from the Site C project beginning no sooner than F2025, what is the $5 billion in Transmission and Distribution "Growth" capital spending needed for? What loads or generators are growing that will require this amount of infrastructure spending? Or is it all needed to deliver the new energy being generated by Site C?

37.0 **Reference: Exhibit B-10, responses to CEBC IRs 1.15.1, 1.15.2, and 1.15.3, Miscellaneous Revenues**

CEBC tried to ascertain the value to BC Hydro of Renewable Energy Credits earned from the sale of energy generated by IPPs in BC and would like additional information.

37.1 What revenue has Powerex been able to achieve over the past 5 years from the sale of Renewable Energy Credits attributed to generation from IPPs in BC?

37.2 Powerex delivers power to California from the BC Hydro System. Under California's Carbon Cap and Trade system power suppliers must procure carbon allowances to offset carbon emissions. Power sourced from BC Hydro and delivered to California is deemed to have a lower carbon content than generic unspecified power or thermal power. Please estimate the annual savings to Powerex for the last three years in the procurement of Carbon Allowances to cover the delivery of BC Hydro sourced power to California, relative to the alternative of procuring carbon allowances if BC Hydro sourced power was considered to have an unspecified carbon content.

37.3 How much of this saving is attributable to IPPs in BC?

37.4 Please provide a table listing all projects which BC Hydro classifies as Independent Power Producers, showing the average annual energy delivered by each over the past 5 years, and indicating which projects generate energy that qualifies for Renewable Energy Credits or low carbon content under California's Cap and Trade rules. Run-of-river projects smaller than 15 MW can be shown as a group (with the number of projects in parentheses), and biomass projects less than 15 MW shown as a group (with the number of projects in parentheses).

38.0 Reference: Exhibit B-10, response to CEBC IR 1.16.3, John Hart

38.1 Please provide the most recent version of the Facility Asset Management Plan for the Campbell River System.

38.2 In Exhibit B-4 of the BCUC review of BC Hydro's application for a CPCN for the John Hart Generating Station Replacement and in response to BCUC IR No. 1.40.3, page 2 of 2, issued July 23, 2012, BC Hydro stated in part, "A conceptual level cost estimate has been developed for reinvestment in the Campbell River System, please refer to Table 3-2 of Exhibit B-1."

38.3 Has this conceptual level cost estimate been updated? If yes please provide it.

39.0 Reference: Exhibit B-10, response to CEBC IR 1.17.3, John Hart Dam Seismic Upgrade

BC Hydro states, "*Investigations have shown that extreme floods on the Campbell River System are best controlled at the Strathcona dam, and any improvements considered for flood handling capability should be focused on that site. Modeling has shown that the annual exceedance probability of a inflow equal to the PMF is in the order of 1/100,000 or less. This compares to the more vulnerable Campbell River seismic withstands that are in the order of 1/1000. Further modifications to increase flood storage at Strathcona will be pursued on an opportunistic basis during other projects involving dam or spillway seismic upgrades."*

39.1 How are extreme floods controlled at the Strathcona Dam?

39.2 How can the Probable Maximum Flood ("PMF") be controlled at the Strathcona dam when the Strathcona Dam spillway can't pass more than 72% of the PMF?

39.3 What does "1/100,000 or less" mean? How is this interpreted?

39.4 How is 1/100,000 calculated and please provide the full details of this calculation?

40.0 Reference: Exhibit B-9, response to BCUC IR 1.82.9, John Hart Dam Seismic Upgrade

BC Hydro states "*...the combined unit cost of energy from both the John Hart Replacement Project and*

the Seismic Upgrade Project would be $87/MWh (in 2019 dollars), plus the cost of energy water rentals. Water rentals are currently $7.30/MWh in real dollar terms, for a total unit energy cost of $94/MWh (in 2019 dollars).

40.1 Does the $94/MWh levelized cost also include the impact of the lost generation as a result of the failure to rehabilitate the Salmon River Diversion? If not, what is the levelized cost including this impact?

40.2 What was the original levelized cost as proposed in the John Hart CPCN?

41.0 Exhibit B-10, response to CEBC IR 1.20.2, Bridge River System

41.1 Other than the estimated mitigation cost of individual assets of the Bridge River System, has BC Hydro developed a conceptual level cost estimate for reinvestment in the Bridge River System? If so, please provide it. If not, why not?

42.0 Exhibit B-10, response to CEBC IR 1.21.1, Large Industrial Sector, Montney shale gas production

42.1 Are the entries in the table under the heading "Montney Shale Gas Production (Bcf/d)" for raw gas or market gas meaning the total volume of gas at the outlet of gas processing plants in B.C.?

42.2 Are the electrical intensity factors provided by BC Hydro in response to CEBC 1.21.4 applied to raw gas or market gas?

42.3 If the values under the heading "*Montney Shale Gas Production (Bcf/d)*" are not for raw gas please provide a new table based on raw gas production.

42.4 Please confirm that in the first quarter of 2016, raw gas production from the B.C. Montney shale fields ("Montney") was approximately 3.5 Bcf/d.

42.5 Please confirm that this figure is expected to markedly increase as more gas processing plants in the Montney that are currently under construction are brought into commercial operation.

42.6 How are energy conservation savings achieved in the Montney through Power Smart?

43.0 Exhibit B-10, response to CEBC IR 1.21.4, Large Industrial Sector, Montney shale gas production

43.1 Please provide the maximum electrical intensity factor for moving the gas from the wellhead to a gas processing plant if this activity is electrified to the fullest technical extent.

43.2 Please provide the maximum electrical intensity factor for a shallow cut gas processing plant if this activity is electrified to the fullest technical extent.

43.3 Please provide the maximum electrical intensity factor for boosting the compression of market gas from a gas processing plant to pipeline level compression if this activity is electrified to the fullest technical extent.

43.4 What percentage of the raw gas from the Montney is processed at the shallow cut or higher level?

43.5 Please provide the maximum electrical intensity factor for a gas drilling rig of the type used in the Montney if this activity is electrified to the fullest technical extent.

43.6 Please provide the maximum electrical intensity factor for fracturing equipment of the type used in the Montney if this activity is electrified to the fullest technical extent.

43.7 Please provide the maximum electrical intensity factor to pump market gas on a MW/MMcf/day/100 kilometer basis in a pipeline if this activity is electrified to the fullest technical extent.

43.8 Please provide the maximum electrical intensity factor on a MW/bbl/day/100 kilometer basis to pump diluted bitumen in a pipeline if this activity is electrified to the fullest technical extent.

44.0 Exhibit B-10, response to CEBC IR 1.21.7, Large Industrial Sector, Montney shale gas production

44.1 Please explain what "*probability-weighted electrical service requests*" means, how BC Hydro makes this calculation and how it was applied to derive the figures in the table that BC Hydro supplied in response to CEBC IR 1.21.1.

44.2 In BC Hydro's response to BCUC IR1.6.1 reference is made to specific adjustments to sales forecasts. What specific adjustments, if any, has BC Hydro made with respect to the total energy requirements associated with BC Hydro's estimated shale gas production?

44.3 In B.C. Hydro's response to BCUC IR 1.6.1 reference is also made to "*other information from Key Account Managers*". What other information, if any, did the key account managers obtain from Montney gas producers and how was it applied the total energy requirements associated with BC Hydro's estimated shale gas production?