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British Columbia Hydro and Power Authority

F2017 to F2019 Revenue Requirements Application

Decision
and Order G-47-18

March 1, 2018

Before:
D. M. Morton, Panel Chair
D. J. Enns, Commissioner
K. A. Keilty, Commissioner

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Executive summary

On July 28, 2016, the British Columbia Hydro and Power Authority (BC Hydro, the Company) filed its Revenue Requirements Application (RRA) requesting approval of rates for the three-year test period (Application) from fiscal 2017 to fiscal 2019 (F2017–F2019 test period). Among the requests set out in the Application, BC Hydro seeks approval of interim and permanent general rate increases of 4.0 percent effective April 1, 2016, 3.5 percent on April 1, 2017 and 3.0 percent on April 1, 2018. These general rate increases reflect the rates as set out in BC Hydro's 2013 10 Year Rates Plan (covering fiscal years 2015 to 2024) and are the maximum allowable under section 9 of the Provincial Government's Direction No. 7 to the Commission.[1] Pursuant to section 9 of Direction No. 7, BC Hydro also requests that the balance of its BC Hydro's revenue requirement which is not forecast to be recovered by the proposed general rate increases above be recorded in the Rate Smoothing Regulatory Account (RSRA).[2]

On November 8, 2017, BC Hydro filed a letter with the Commission (Amended Application) seeking certain amendments to its fiscal 2019 proposed rate increase. In particular, BC Hydro seeks approval to:

i. change its requested rate increase for fiscal 2019 from 3 percent to 0 percent; and
ii. maintain its 2018 Open Access Transmission Tariff rates for fiscal 2019

Upon review through a written hearing, the Panel approves BC Hydro's Application and Amended Application with the following exceptions:

1. BC Hydro's Amended Application is not approved and rates are set at the amount requested in the original application. The Panel finds that there is insufficient regulatory justification to approve the zero percent rate increase in the Amended Application.
2. BC Hydro's proposal to change the scope and name of the Future Removal and Site Restoration Regulatory Account is denied and the Panel further directs BC Hydro to close out this regulatory account in F2017 once the balance has been drawn down to zero. For the F2017 to F2019 test period only, the Panel directs the establishment of a new regulatory account, the Dismantling Cost Regulatory Account (DCRA), to defer, on an annual basis, any variances between planned and actual dismantling costs during the F2017 to F2019 test period subsequent to the full draw down of the Future Removal and Site Restoration Regulatory Account.
3. The Panel denies BC Hydro's proposal to include in the Non-Current Pension Costs Regulatory Account the deferral of the annual variance between the forecast costs and actual costs related to the operating cost portion of post-employment benefit current pension costs. The Panel directs the establishment of a new regulatory account, the Post Employment Benefit (PEB) Current Pension Costs Regulatory Account, to defer the annual variance between the forecast costs and actual costs related to the operating cost portion of PEB Current Pension Costs to be amortized over the subsequent test period. The F2016 variance of $17.2 million approved by Order G-148-15 is to be amortized over the F2017–F2019 test period. The Panel also denies BC Hydro's proposal to use an average of actual past discount rates used in the calculation of actual current service costs in the preceding five fiscal years for forecasting purposes.

[1] Direction No. 7 to the British Columbia Utilities Commission, OIC 097/2014 and amended OIC 405/2015.
[2] Exhibit B-1-1, pp. 1-1, 1-3.

Rates

In its review of the Application and the Amended Application, the Panel considered the 10 Year Rates Plan and the impact of deferring the collection of the Revenue Requirement during the test period. Interveners expressed concerns about the risks associated with the recovery plan for the RSRA. The Panel generally agrees with these concerns. Key among these concerns are:

1. the historical tendency to over-forecast load; and
2. the Cost of Energy, especially that acquired from Independent Power Producers (IPPs).

Because BC Hydro's actual load has been less than its forecast since F2009, there have been significant additions to the Non Heritage Deferral Account (NHDA) every year. The annual variance related to domestic revenues has steadily increased from $20 million in F2009 to $269 million in F2016 for total additions of $998 million in 8 years. On average the variance has been $125 million per year over the fiscal 2009 to fiscal 2016 period and the average annual addition has been $171 million over the last five-year (i.e., fiscal 2012 to fiscal 2016) period.

Additions to the deferral account arise not only because of variances between forecast and actual domestic demand, but also from purchases of energy from long term contractual obligations. If this oversupply cannot be managed there will continue to be upward pressure on BC Hydro's rates. The Commission also grapples with its requirement under Direction no. 7 to set rates to allow BC Hydro to clear the balances of regulatory accounts from time to time and within a reasonable period.

In its consideration of the Amended Application to "freeze" rates in F2019, the Panel considered the recent history of rate increases (both in nominal and real terms), the risk of additional upward pressure on future rates, and the concerns of growing deferral and regulatory accounts due to BC Hydro's load forecast and cost of energy. Accordingly, the Panel finds that there is not sufficient regulatory justification for approving real rate decreases.

Load forecast

In its review of BC Hydro's load forecast for the test period, the Panel observes that since the 10 Year Rate Plan was first prepared in 2013, forecast revenues have declined by $3.5 billion, comprised mainly of reductions in forecast revenues from large industrial customers, reductions in the forecast growth of large industrial load, reductions in forecast revenues from LNG, and reductions in revenues in fiscal 2015 and fiscal 2016 which reduced sales to residential customers.

Even though BC Hydro identifies challenges in forecasting revenues and states that variances are due to variables that are beyond its control, it continues to forecast improvements in the industrial load forecast. Although, the F2017 actuals have tracked fairly closely to forecast, this is not an indicator that the next two years will track accurately. The Panel notes that other utilities such as Pacific Northern Gas Ltd., FortisBC Energy Inc. and FortisBC Inc. use a different load forecast methodology for their short-term forecast for setting rates as compared to its long-term forecast for resource planning.

We further note that the forecast for the remaining two years of the test period does not reflect a significant upward trend. The average of the forecast load for the next two years, 52,251 GWh, is virtually identical to the average of the actual load of 52,173 GWh for the past five years. The Panel is of the view that the forecast for the remaining two years of the test period appears reasonable given the current economic circumstances.

The Panel also recognizes that any adjustments to BC Hydro's load forecast result in a shifting of variances from the NHDA to the RSRA, and therefore for the purpose of this test period, accepts the load forecast as reasonable and declines to make any adjustments.

Cost of Energy

As required by Direction No. 7, the Panel determined the energy required by BC Hydro to meet its domestic service obligations and the cost to BC Hydro of the portion of that required energy that is in excess of the energy supplied under the heritage contract. That determination is shown in the table below:

	2017	2018	2019
Non-Heritage Energy Required (GWh)	**8,472**	**8,497**	**9,399**
Unit Cost of Non-Heritage Energy ($MWh)	**$92.30**	**$91.30**	**$94.70**
Cost of Non Heritage Energy ($mil)	**$782**	**$776**	**$890**
BC Hydro's Forecast Costs of total Non-Heritage Energy ($mil)	**$1,312**	**$1,510**	**$1,547**

The Panel identified the following issues and requested further information from BC Hydro in a compliance filing:

1. Heritage Assets may not be providing optimal value to BC Hydro customers as anticipated in the Heritage Contract.
2. The discrepancy between the Heritage Energy forecast in the Load Resource Balance and forecast in Table 4 of Appendix A in the Application.
3. The accounting treatment of surplus energy costs and recoveries.
4. The cost of IPPs and Long-Term Commitment included in BC Hydro's Cost of Energy.

BC Hydro's forecast Cost of Energy consists of mostly payments on contracts that were entered into prior to 2017 along with the incremental costs of providing Heritage Energy. The Panel recognizes the $2.1 billion in reduced purchase commitments that BC Hydro has already achieved. However there remains a significant amount of additional surplus energy acquisitions. However, the Commission is required by Direction No. 7 to allow BC Hydro recovery of these costs. Accordingly, the Panel approved the forecast Cost of Energy.

The Panel recommends that in the 2018 Integrated Resource Plan (IRP) process, BC Hydro's approach to optimizing its portfolio is reviewed. Further we recommend that BC Hydro consider the timing of its existing IPP contracts and contract renewals. In particular, it would benefit ratepayers if the timing of the delivery of energy was more aligned with BC Hydro's forecast load, after allowing for the Heritage Energy.

The Panel also recommends a review of the appropriateness of five years between refreshes of the IRP. Five years can be a long time - prices for clean energy have dropped significantly during the five years since the previous IPP review and also BC Hydro's demand has also fallen short of the previously forecasts.

Operating Costs

We are not convinced that an annual increase commensurate with inflation is a solid reason for supporting the reasonableness of BC Hydro's forecast costs in the test period. However, the Panel recognizes that there will be a "comprehensive review of BC Hydro that is expected to begin in fiscal 2018 and is likely to be completed in fiscal 2019."[3] Accordingly, the Panel is reluctant to make any adjustments to BC Hydro's operating costs at this time. The Panel notes however that reducing operating costs is one of the few steps BC Hydro can take to reduce it revenue requirements with immediate effect. The Panel has identified a number of areas of concern and recommends these areas be included in the government's upcoming review. The Commission may also perform its own investigation in future revenue requirement applications.

Capital Costs

The Panel finds BC Hydro's forecast capital additions reasonable for the F2017 to F2019 test period. With respect to forecast capital expenditures, the Panel considers that certain projects could have potentially significant public interest issues and directs BC Hydro to file CPCN applications, if there is intention to pursue any of these extensions:

a. Metro North Transmission
b. West Kelowna Transmission/Westbank Substation Upgrade
c. Northwest Substation Upgrade
d. Peace Region to Kelly Lake 500kV Transmission Reinforcement
e. Mainwaring Substation Upgrade

The Panel finds that although overall BC Hydro projects delivered between fiscal 2012 to fiscal 2016 were comparable to budget in aggregate, there were several larger projects where BC Hydro was significantly over budget. The Panel recommends the issue of the adequacy of BC Hydro's planning and execution related to large capital projects be explored in this upcoming BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding.

Future Revenue Requirement Reviews

Much of the discussion in these findings underlines our concern in the apparent decoupling of revenues and expenditures within the test period. Expenditures have risen faster than revenues and this situation is not sustainable. Accordingly, a Performance Based Rate (PBR) setting mechanism could help BC Hydro accomplish its cost control objectives and provides incentives for utilities to improve productivity and create efficiencies to allow for rates to be more effectively managed, while maintaining service quality. Section 60(1)(b.1) of the UCA provides the necessary legislative framework for a PBR plan. Accordingly, the Panel directs BC Hydro to file, by June 30, 2018, a report outlining a potential PBR plan in the next test period.

[3] Exhibit B-23, p. 3.

1.0 Introduction

On July 28, 2016, the British Columbia Hydro and Power Authority (BC Hydro, the Company) filed its Revenue Requirements Application (RRA) requesting approval, from the British Columbia Utilities Commission (BCUC, Commission), of rates for the three-year test period (Application) from fiscal 2017 to fiscal 2019 (F2017 – F2019 test period). This Application, originally scheduled for filing in late February 2016, was delayed to July 2016 as BC Hydro required additional time to determine the impact on its demand and revenue forecast as a result of a reduction in its industrial customer load growth.[4]

Among the requests set out in the Application, BC Hydro seeks approval of interim and permanent general rate increases of 4.0 percent effective April 1, 2016, 3.5 percent on April 1, 2017 and 3.0 percent on April 1, 2018. These general rate increases reflect the rates as set out in BC Hydro's 2013 10 Year Rates Plan (covering fiscal years 2015 to 2024) and are the maximum allowable under section 9 of the provincial government's Direction No. 7 to the Commission.[5] Pursuant to section 9 of Direction No. 7, BC Hydro also requests that the balance of its BC Hydro's revenue requirement which is not forecast to be recovered by the proposed general rate increases above be recorded in the Rate Smoothing Regulatory Account (RSRA).[6]

On November 8, 2017, BC Hydro filed a letter with the Commission (the Amended Application) seeking certain amendments to its fiscal 2019 proposed rate increase to essentially "freeze" the F2019 rates from F2018 rates (the rate freeze). In particular, BC Hydro seeks approval to:

i. change its requested rate increase for fiscal 2019 from 3 percent to 0 percent; and
ii. maintain its 2018 Open Access Transmission Tariff rates for fiscal 2019.

1.1 The Applicant

BC Hydro is a Crown corporation established under the *Hydro and Power Authority Act*. BC Hydro is the third largest electric utility in Canada serving 95 percent of British Columbia's population[7] with 1.9 million customer accounts comprised of a customer base of 4 million people and businesses. BC Hydro's system includes 30 hydroelectric generating facilities and two natural gas-fired generating facilities. In addition, there are 127 independent power producer (IPP) project owners and operators with whom BC Hydro contracts to purchase energy.

BC Hydro delivers electricity over 78,000 kilometers of transmission and distribution lines. The transmission system includes facilities used to transmit electricity, usually at voltages greater than 69 kilovolts (kV); and the distribution system includes electrical lines, cables, transformers and switches used to distribute electricity from substations to customers, generally at voltages lower than 69 kV.[8]

[4] Exhibit B-1-1, pp. 1-1 to 1-3.
[5] Direction No. 7 to the British Columbia Utilities Commission, OIC 097/2014 and amended OIC 405/2015.
[6] Exhibit B-1-1, pp. 1-1, 1-3.
[7] Ibid, p. 1-5.
[8] Ibid, p. 1-5.

1.2 Approvals sought

BC Hydro originally outlined its approvals sought in Appendix T of the Application. These items were subsequently restated in its Final Argument to reflect updates, errata and commitments made during the proceeding.[9] Accordingly, the final approvals sought, along with the sections of the decision in which the approvals are addressed, are:

Approval Sought	Location in this Decision
Final rate increases of 4.0 percent, 3.5 percent and 3.0 percent, to be applied as set out in Appendix T of the Application, and effective April 1, 2016, April 1, 2017 and April 1, 2018, respectively.	Section 5.1
The requested final Open Access Transmission Tariff (OATT) rates for F2017 - F2019 as set out in Appendix T of the Application, and corrected in Errata No. 1[10] to be approved effective April 1, 2016, April 1, 2017 and April 1, 2018, respectively. The difference between the final OATT rates and the interim refundable OATT rates is to be collected from applicable customers through a one-time charge as described in Chapter 9 of the Application.	Section 5.1
BC Hydro be directed to re-calculate its revenue requirements, including its rate of return, based on the updates, errata and commitments made by BC Hydro.	Section 5.1
Pursuant to Direction No. 7, BC Hydro be directed to record in the Rate Smoothing Regulatory account for each year of the test period the difference between BC Hydro's recalculated revenue requirements and the revenues expected to be collected under the approved rates.	Section 5.1
Approval of the requested depreciation rates for property, plant and equipment at the Burrard synchronous condense facility as set out in Table 8-1 of the Application.	Section 4.1
Approval of the requested changes to deferral and regulatory accounts and associated financial treatment, as described in Chapter 7, summarized in Table 7-9 of the Application and clarified in Part Nine E and F of the Final Submission.	Section 3.4
Acceptance of the requested demand-side management expenditure schedule for F2017 – F2019, as set out in Table 10-1 of the Application and revised in BC Hydro's response to BCUC IR 314.3, for a total expenditure over the test period of $361.1 million.	Section 3.5

1.3 Regulatory process and participants

Subsequent to the Commission's approval of BC Hydro's interim rate increase of 4.0 percent effective April 1, 2016,[11] the Commission Panel hosted a number of Community Input Sessions throughout the province to

[9] BC Hydro Final Argument, pp. 260–263.
[10] Exhibit B-1-2.
[11] Order G-40-16, dated March 22, 2016.

promote a public understanding of the scope of the Commission's review in this Application. The Commission visited five urban centers in the province (Victoria, Nanaimo, Prince George, Fort St. John and Vancouver).

The intent of the Community Input Sessions was to inform members of the public on how to participate in the Commission's regulatory processes, to explain the scope of BC Hydro's Application, and provide an opportunity for parties to dialogue with the Panel appointed by the Commission to consider their interests specific to this Application.[12]

The Commission also held two Procedural Conferences on September 1, 2016 and November 28, 2016, and invited comments from interveners on a number of scope and procedural matters.

Subsequent to the procedural conferences, the Commission issued Orders G-144-16 and G-7-17 establishing the Regulatory Timetable to review the Application through a written hearing process and determined that the scope of the review will be focused on the F2017 – F2019 test period including expenditures that affect future years beyond the test period, and on aspects that the Commission retains discretion over while recognizing that some matters are to be discussed in separate proceedings.

There were seventeen registered interveners and five interested parties to this proceeding. The registered interveners were:

- BC Sustainable Energy Association and the Sierra Club of British Columbia (BCSEA);
- Movement of United Professionals (MoveUp);
- British Columbia Old Age Pensioners' Organization et al. (BCOAPO);
- Clean Energy Association of BC (CEABC);
- Mr. Richard McCandless;
- Peace River Regional District (PRRD);
- TransCanada Energy Ltd. (TCE);
- FortisBC Energy Inc., and FortisBC Inc. (FortisBC);
- Association of Major Power Customers of British Columbia (AMPC);
- Commercial Energy Consumers Association of British Columbia (CEC);
- Non-Integrated Areas Ratepayers Group (NIARG);
- Skywind Foundation (Skywind);
- Ms. Gwen Johansson;
- Save Our Northern Seniors (SONS);
- Mr. Richard Landale;
- Ms. Margaret Little, and Mr. James Little; and
- Zone II Ratepayers Group (Zone II).

The Commission also received letters of comment from members of the public in this proceeding.

The Commission's regulatory review process for this Application included two rounds of information requests (IR) to BC Hydro, Intervener Evidence and IRs on that evidence, rebuttal and additional evidence from BC Hydro and IRs on that evidence; followed by final and reply arguments from all parties.

[12] Exhibit A-4-1.

During the course of this proceeding, and in accordance with Direction No. 7 to the BCUC, the Commission approved the following interim rate increases, subject to the further review of the evidence filed:

- Order G-40-16 dated March 22, 2016, approved an interim increase of 4.0 percent effective April 1, 2016.
- Order G-39-17 dated March 16 2017, approved a further 3.5 percent rate increase effective April 1, 2017.

Additionally, on August 2, 2017, the Lieutenant Governor in Council requested the Commission to advise the Lieutenant Governor in Council respecting BC Hydro's Site C project. In light of the requirement for the Commission to review additional details related to BC Hydro's 2016 load forecast as part of the Site C Inquiry, the Panel considered it appropriate to provide its findings on the 2016 Load Forecast for the fiscal 2017 to fiscal 2019 test period in advance of issuing its full decision on the remaining issues and determinations on approvals sought in the Application. Accordingly, on August 25, 2017, the Commission issued the Panel's Key Findings on the 2016 Load Forecast for the fiscal 2017 to fiscal 2019 test period.

Subsequent to the filing of final and reply arguments by BC Hydro and interveners, BC Hydro filed its Amended Application. Accordingly, the Commission held a procedural conference and subsequently issued Orders G171-17 and G-16-18 establishing the Regulatory Timetable to review the Amended Application through a written hearing process. The regulatory review process for the Amended Application included one round of IRs, limited in scope to matters related to the amended requests, followed by final and reply arguments from all parties.

2.0 Approach to the Decision

This section of the decision outlines the Panel's approach in the review and consideration of the evidence filed in this proceeding and acknowledges the concerns and issues raised by various parties. The Panel outlines it views on whether the review of the Application should extend beyond the test period, considerations related to the legislative and legal parameters impacting the Commission's regulatory oversight of BC Hydro. The Panel then examines the issues related to BC Hydro's revenue requirements, including operating and capital costs, deferral accounts, demand side management, and other items. Finally, the Panel will discuss the 2013 10 Year Rates Plan and the Amended Application, providing its overall direction and determinations on this Revenue Requirement Application.

2.1 Focus on the test period

Parties to this proceeding have provided various submissions that pertain to longer term issues and concerns beyond the test period. These include BC Hydro's load forecast and the Company's ability to amortize deferral account balances in accordance with the schedule provided in the Application.

Panel discussion

The Panel's focus is on the F2017–F2019 test period as previously stated in the Panel's Reasons for Decision accompanying Commission Order G-144-16. Specific approvals granted in this decision will also be aligned with this determination. Further, the scope of the proceeding was reiterated by the Panel in its Key Findings on the 2016 Load Forecast issued August 25, 2017, in which the Panel's review was focused on the load forecast as it related to the F2017 – F2019 test period as inputs to calculating BC Hydro's revenue forecast and the cost of energy component of BC Hydro's proposed revenue requirement.

2.2 Legal and legislative framework

The Commission's oversight of BC Hydro is impacted by a number of key enactments and policies that also affect BC Hydro's plans and actions in the test period and beyond. These include applicable statutory provisions and regulatory requirements contained in the *Hydro and Power Authority Act*, the *Clean Energy Act*, and the *Utilities Commission Act* (UCA), in particular sections 59-60. In addition, BC Hydro, and the Commission must also consider specific directions enacted through a several Order in Council's (OICs). The most notable of these is, Direction No. 7, to which the Panel must adhere. Direction No. 7 requires the Commission to:

1. Cap rate increases during the test period and the balance of BC Hydro's [allowed] forecast revenue requirements to be transferred to the Rate Smoothing Regulatory Account (RSRA).
2. Maintain the deferral account rate rider (DARR) at 5 percent.
3. Ensure that the rates allow BC Hydro to collect sufficient revenue to enable it to (a) provide reliable electricity service, (b) meet all of its debt service, tax and other financial obligations, and (c) comply with government policy directives requiring BC Hydro to construct, operate or extend a plant or system.
4. Allow BC Hydro to recover a number of specified costs in its forecast revenue requirements.
5. Refrain from performing certain duties under the *Clean Energy Act* regarding expenditures for export and may not exercise any power under the Utilities Commission Act in regard to certain activities of Powerex.[13]

In addition, BC Hydro notes there are also directions relating to cost of energy, operating expenses, capital and demand side management (DSM).[14]

BC Hydro summarizes some of the key regulatory statutes that impact the Commission's oversight and review of this Application:

[13] Exhibit B-1-1, pp. 2-6 to 2-10.
[14] Ibid, p. 2-6.

Table 2-1: Key Regulatory Statutes[15]

Policy Area	Synopsis	Source
British Columbia Utilities Commission Review Exemptions	BC Hydro is exempt from sections 45 to 47 and 71 (Certificate of Public Convenience and Necessity & Energy Supply Contracts) of the *Utilities Commission Act* to the extent applicable, with respect to the following projects, programs, contracts and expenditures of BC Hydro: • The Northwest Transmission Line, • Mica Units 5 and 6, • Revelstoke Unit 6, • Site C Clean Energy Project, • A bio-energy Phase 2 call to acquire up to 1 000 gigawatt hours per year of electricity, • One or more agreements with pulp and paper customers eligible for funding under Canada's Green Transformation Program, • The clean power call request for proposals, • The standing offer program.	*Clean Energy Act*
British Columbia Utilities Commission Review Exemptions	Section 32 of the *BC Hydro Power and Authority Act* exempts BC Hydro from sections 50, 51 (c), and 52 of the *Utilities Commission Act* with respect to the need for British Columbia Utilities Commission approval to issue securities, including the setting of interest rates for those securities, or for the disposition of property.	*BC Hydro Power and Authority Act*
Dividend	Special Direction HC1 sets out the dividend calculation for BC Hydro.	HC1
Expenditures for Export	The British Columbia Utilities Commission must refrain from performing its duty under section 4 (5) of the *Clean Energy Act* when setting rates for BC Hydro for F2014, F2015, F2016, F2017, F2018 and F2019. Section 4(5) of the *Clean Energy Act* states: "(5) In setting rates for BC Hydro, the British Columbia Utilities Commission must ensure that the rates do not allow the authority to recover: (a) its expenditures for export as set out in a report approved by the Lieutenant Governor in Council under subsection (4), and any other expenditures for export."	Direction No. 7 Order in Council No. 539
Thermal-Mechanical Pulping Program	The British Columbia Utilities Commission must not disallow for any reason the recovery of rates of the costs incurred by the authority in carrying out the Thermal-Mechanical Pulping program. The costs recovered by rates cannot exceed $100 million. BC Hydro is to defer to the Demand-Side Management Regulatory Account costs incurred as a result of carrying out the Thermal-Mechanical Pulping program.	Order in Council No. 404 (TMP Pricing)

15 Ibid, pp. 2-20 – 2-22, Extracted portion of Table 2-6.

Policy Area	Synopsis	Source
Mining Customers	The British Columbia Utilities Commission must allow BC Hydro to establish a regulatory account to defer to future fiscal years amounts equal to the sum of the impaired account balances of mining customers (refer to Order in Council for definition of eligible). This account will include interest charges determined in a fiscal year at a rate equal to BC Hydro's weighted average cost of debt in that fiscal year.	Order in Council No. 123 (Mining)

Direction No. 7 further prescribes the scope of the Commission's review of these expenditures as illustrated by the excerpts below:

Basis for establishing authority revenue requirements

4. Subject to section 7, in regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to
    a) provide reliable electricity service,
    b) meet all of its debt service, tax and other financial obligations,
    c) comply with government policy directives, including, without limitation, government policy directives requiring the authority to construct, operate or extend a plant or system, and
    d) achieve an annual rate of return on deemed equity,
        i. for F2017, that would be necessary to yield a distributable surplus of $684 million,
        ii. for F2018, that would be necessary to yield a distributable surplus of $698 million, and
        iii. for F2019 and subsequent fiscal years, that would be necessary to yield a distributable surplus of $712 million.

Determining the cost of energy

5. In setting the authority's rates, the commission
    a) must treat the heritage contract as if it were a legally binding agreement between 2 arms-length parties,
    b) must determine the energy required by the authority to meet its domestic service obligations and must determine the cost to the authority of the portion of that required energy that is in excess of the energy supplied under the heritage contract,
    c) may employ any mechanism, formula or other method authorized by section 60 (1) (b.1) of the Act, and
    d) unless a different mechanism, formula or method is employed under paragraph (c), must ensure that electricity used by the authority to meet its domestic service obligations is provided to customers on a cost-of-service basis.

Regulatory Accounts

7. When regulating and setting rates for the authority, the commission

   a) must allow the authority to continue to defer to the heritage deferral account the variances between the actual and forecast heritage payment obligation,

   b) must allow the authority to continue to defer to the trade income deferral account the variances between actual and forecast trade income,

   c) must, in regard to the non-heritage deferral account, allow the authority to

      (i) continue to defer to that account the variances between actual and forecast cost of energy arising from differences between actual and forecast domestic customer load, and

      (ii) defer to that account the Burrard costs,

   d) must, in regard to the DSM regulatory account, allow the authority to

      (i) defer to that account the authority's costs arising from its development, implementation and administration of demand-side measures, including costs arising from specified demand-side measures and public awareness programs, and

      (ii) amortize from that account in each fiscal year an amount equal to the sum of

         (A) the amount amortized in the immediately preceding fiscal year less the amortization in that year associated with costs incurred more than 15 fiscal years prior to that year, and

         (B) the product of the amount deferred to that account in the immediately preceding fiscal year and 1/15,

   e) must allow the authority to continue to defer to the Rock Bay remediation regulatory account the Rock Bay costs,

   f) must allow the authority to continue to defer to the asbestos remediation regulatory account the variances between actual and forecast asbestos remediation costs,

   g) must allow the authority to continue to defer to the non-current pension costs regulatory account the variances between actual and forecast non-current pension costs,

   h) must allow the authority to establish the following regulatory accounts:

      (i) an account to defer for recovery in rates in future fiscal years of the authority those portions of the authority's allowed revenue requirement in a particular fiscal year that were not or are not to be recovered in rates in that particular fiscal year;

      (ii) an account to defer the variances between the authority's actual and forecast real property gain/loss,

   i) must allow the following regulatory accounts to accrue interest in a fiscal year at the authority's weighted average cost of debt in that year:

      (i) the first nations costs regulatory account;

      (ii) the real property sales regulatory account,

   j) may allow the authority to establish one or more other regulatory accounts for other purposes, and

k) subject to section 9 (1) of this direction, must set the authority's rates in such a way as to allow the regulatory accounts to be cleared from time to time and within a reasonable period.

Annual distributable surpluses allowed

8. When regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to allocate annual distributable surpluses in the manner specified by the Lieutenant Governor in Council under section 4 of the *BC Hydro Public Power Legacy and Heritage Contract Act* or section 35 of the *Hydro and Power Authority Act.*

F2017, F2018 and F2019 rates

9. (1) When regulating and setting rates for the authority for F2017, F2018 and F2019, under sections 4, 5, 6, 7, 9 (2), 10 (3) and 11 of this direction, the commission must not allow the rates to increase by more than 4% in F2017, 3.5% in F2018 and 3% in F2019, on average, compared to the rates of the authority immediately before the increase.

(2) If the base line rate change exceeds 4% in F2017, 3.5% in F2018 or 3% in F2019, the commission must order the authority to defer to the rate smoothing regulatory account the amount that is determined by subtracting the amount in paragraph (b) from the amount in paragraph (a)

a) the forecast revenue that the authority would have earned under a base line rate change, and

b) the forecast revenue that the authority is expected to earn under this direction.

(3) In setting the authority's rates for F2017, F2018 and F2019 under sections 4, 5, 6, 7, 9 (2), 10 (3) and 11 of this direction, the commission must not set rates for the authority for the purpose of changing the revenue-cost ratio for a class of customers.

Commission reviews

11. When setting rates for the authority under the Act, the commission must not disallow for any reason the recovery in rates of the costs that were incurred by the authority or Powerex Corp. in consequence of decisions of either with respect to

a. the construction of extensions to the authority's plant or system that come into service before F2017,
b. energy supply contracts entered into before F2017,
c. the Rock Bay settlement,
d. the First Nations settlements,
e. the California settlements,
f. the Burrard costs, and
g. the costs deferred to the Smart Metering Infrastructure (SMI) regulatory account.

Expenditures for export

12. The commission must refrain from performing its duty under section 4 (5) of the *Clean Energy Act* when setting rates for the authority for F2014, F2015, F2016, F2017, F2018 and F2019.

Burrard Thermal

15. On application by the authority the commission must

a) grant permission to the authority under section 41 of the Act to cease operating those portions of Burrard Thermal that are not required for transmission support services, and b) set depreciation rates for the classes of property, plant and equipment at Burrard Thermal as shown in Appendix B to this direction.
Rates 16. 1) The commission may not reconsider, vary or rescind the orders it issues under this direction or Direction No. 6 to the British Columbia Utilities Commission, except on application by the authority. 2) For F2014, F2015 and F2016, the commission must not issue any orders in regard to the authority's regulatory accounts, except on application by the authority. 3) In setting the authority's rates for F2015, F2016, F2017, F2018 and F2019, the commission must exercise its powers and perform its duties consistently with the orders it issues under Direction No. 6 to the British Columbia Utilities Commission, except on application by the authority. 4) Nothing in this section prevents the commission from making determinations on applications made by the authority respecting revenue-cost ratios, rate design and regulatory accounts, including interim rate orders in regard to one or more of the authority's customers.

These directives to the Commission, in addition to the statutory framework provided by the UCA, including sections 59–60 concerning rate setting, the *Clean Energy Act* (CEA) the *BC Hydro Public Power Legacy and Heritage Contract Act*, the *Hydro and Power Authority Act* and other Directions to the Commission guide the Panel in its review of these revenue requirements.

BC Hydro also states the government issues a letter each year that confirms BC Hydro's mandate, provides government's strategic direction and sets out key performance expectations for the fiscal year. BC Hydro identifies the strategic actions set out in the Minister's Mandate Letter in section 2.2.5 of the Application. BC Hydro submits the Minister's March 14, 2016 Mandate Letter sets the priorities for the test period and has implications for its operating expenses, capital, cost of energy and DSM expenditures.[16]

Panel discussion

The legislative framework currently in place for BC Hydro has considerable effect on the scope of the Commission's review of BC Hydro's 2017–2019 RRA. Although some parties to this proceeding including CEC,[17] Landale,[18] McCandless,[19] MoveUp[20] and BCOAPO[21] have challenged these legislative parameters, the Panel cannot consider these challenges because they are outside of the Commission's jurisdiction.

[16] BC Hydro Final Argument, p. 12.
[17] CEC Final Argument, p. 13.
[18] Landale Final Argument, p. 6.
[19] McCandless Final Argument, p. 2.
[20] MoveUp Final Argument, p. 9.
[21] BCOAPO Final Argument, p. 8.

3.0 Revenue requirement – key issues

The Panel reviews BC Hydro's revenue requirement components to determine whether the forecasts presented are reasonable within the context of its three -year test period, the legislative parameters as outlined in section 2.2, and whether the approvals sought will support just and reasonable rates, as outlined in section 59–60 of the *UCA*.

Direction 6 and 7 give little or no discretion to the Commission with respect to:

- finance charges and amortization related to capital projects previously exempt from Commission oversight,
- depreciation, interest, finance charges and other capital expenses related to heritage assets,
- return on equity, and
- deferral account rate rider revenue.

Accordingly, the Panel approves these items.

The Panel finds taxes, non-tariff revenue, inter-segment revenue, subsidiary net income, and other utilities revenue to be reasonable forecasts for the three-year test period.

In subsections 3.1 to 3.5, the Panel identifies a number of issues related to other components of BC Hydro's revenue requirements and provides its findings and determinations on these key issues. These are: cost of energy, operating (O&M) costs, capital related issues, deferral and regulatory account requests, and demand side management. Other issues are identified and discussed by the Panel in section 4.

In the Application, and as subsequently updated in the Amended Application, BC Hydro requests approval for its total revenue requirements for F2017, F2018 and F2019 of $4,679.9 million, $4,912.1 million, and $5,137.6 million, respectively.[22] Subsequent to transfers of amounts in excess of what can be collected in rates to the RSRA, and pursuant to section 9(2) of Direction No. 7, the revenue proposed to be recovered from ratepayers is $4,469.9 million, $4,626.2 million, and $4,695.9 million respectively for each year in the test period:

Table 3-1: Fiscal 2017 to Fiscal 2019 Amounts Transferred to the Rate Smoothing Regulatory Account

Updated Table 1-8 Fiscal 2017 to Fiscal 2019 Amounts Transferred to the Rate Smoothing Regulatory Account[1]

	F2017 ($ million)	F2018 ($ million)	F2019 ($ million)	F2019 Rate Freeze ($ million)
Total Revenue Requirements	4,679.9	4,912.1	5,136.1	5,137.6
Revenue Recovered under Rate Caps	4,469.9	4,626.2	4,836.8	4,695.9
Amount Transferred to Rate Smoothing Regulatory Account	210.0	285.9	299.4	441.7
Rate Smoothing Regulatory Account Balance	497.4	783.3	1,082.7	1,225.0

[22] Exhibit B-1-1, p. 1-44.

BC Hydro submits that the forecast revenue requirements in the test period represent the cost of investing to meet system requirements, providing safe and reliable service to customers, and reflect BC Hydro's significant effort to manage and control costs in order to deliver on the 2013 10 Year Rates Plan.[23]

3.1 Cost of Energy

BC Hydro's Cost of Energy is the sum of the cost of Heritage Energy and the cost of Non-Heritage Energy. Heritage Energy refers to energy or capacity associated with BC Hydro's 30 hydroelectric generation facilities, also known as BC Hydro's Heritage Resources. The cost of Heritage Energy is the cost that BC Hydro incurs to provide up to 49,000 GWh per year under the Heritage Contract to serve domestic load obligations.[24] Non-Heritage Energy refers to energy from other sources, such as energy obtained through Electricity Purchase Agreements with Independent Power Producers (IPPs).[25] The cost of Non-Heritage Energy is the cost that BC Hydro incurs to provide energy from Non-Heritage sources to serve domestic load.[26]

BC Hydro submits that its forecast Cost of Energy "is based on a sound methodology and reasonable assumptions." Further, it requests that the Commission find that its forecast Cost of Energy for the test period, the vast majority of which is associated with Heritage Resources and energy purchase agreements with IPPs that are covered by Direction No.7, is reasonable. BC Hydro further submits that the Commission's determination on the forecast, while necessary for rate setting purposes, will not impact the *actual* Cost of Energy paid by customers that is "trued up" using existing deferral accounts.[27]

BC Hydro points out that it is not requesting approval for any Electricity Purchase Agreements in this Application, so the Commission should not make any determinations on the appropriate renewal terms. BC Hydro further states that it will be filing with the Commission any renewed Electricity Purchase Agreements, as required, under section 71 of the UCA.[28]

The Panel will review BC Hydro's forecast cost of energy, and the requirements of Direction No. 7 in order to assess the reasonableness of BC Hydro's forecast cost of energy.

BC Hydro presents the following summary of its recent actual and test period forecast energy costs:

---

[23] BC Hydro Final Submission, p. 1.
[24] Exhibit B-1-1, p. 4-2.
[25] Ibid., p. 4-1.
[26] Ibid., p. 4-3.
[27] BC Hydro Final Argument, p. 81.
[28] Ibid.

Table 3-2: Summary of Energy Costs[29]

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1				**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**	**Reference**						
2				**Actual**	**Actual**	**Actual**	**Plan**	**Plan**	**Plan**							
3	**Cost of Energy ($ million)**															
4		**Heritage Energy**														
5			*Total ($million)*	$ 406.40	$ 388.90	$ 206.08	$ 279.28	$ 250.24	$ 279.32	Exhibit B-1-1, Appendix A, Schedule 4.0, line 34						
6			*Total (GWh)*	45,877	41,197	42,022	43,095	41,473	42,182	Exhibit B-1-1, Appendix A, Schedule 4.0, line 8						
7																
8		**Non-Heritage Energy**														
9			Waneta (water rentals)	$ 7.40	$ 7.29	$ 7.61	$ 6.81	$ 6.42	$ 6.31	Exhibit B-1-1, Appendix A, Schedule 4.0, line 36						
10			IPPs and Long-Term Commitments (with capital leases)	$ 887.30	$1,129.39	$1,292.51	$1,312.55	$1,509.92	$1,547.88	Exhibit B-1-1, Appendix A, Schedule 4.0, line 106						
11			Non-Integrated Area	$ 28.80	$ 25.53	$ 22.63	$ 24.61	$ 27.36	$ 31.14	Exhibit B-1-1, Appendix A, Schedule 4.0, line 39						
12			Gas & Other Transportation	$ 12.90	$ 10.63	$ 10.49	$ 10.57	$ 10.11	$ 6.08	Exhibit B-1-1, Appendix A, Schedule 4.0, line 40						
13			Net Purchases (Sales) from Powerex	$ 28.90	$ 16.20	-$ 0.08	-$ 6.45	-$ 5.98	$ 0.74	Exhibit B-1-1, Appendix A, Schedule 4.0, line 42						
14																
15			*Total ($million)*	$ 965.30	$1,189.04	$1,333.17	$1,348.08	$1,547.84	$1,592.16	Exhibit B-1-1, Appendix A, Schedule 4.0, line 43; Exhibit B-9, BCUC IR 23.2						
16			*Total (GWh)*	12,033	14,531	14,837	14,067	15,714	15,907	Exhibit B-1-1, Appendix A, Schedule 4.0, line 13						
17																
18		**Total Gross COE** with Capital Leases **($million)**		**$1,371.70**	**$1,577.93**	**$1,539.25**	**$1,627.37**	**$1,798.08**	**$1,871.48**	Exhibit B-1-1, Appendix A, Schedule 4.0, line 44; Exhibit B-9, BCUC IR 23.2						
19		**Total Weighted Cost** without Capital Leases **($/MWh)**		**$ 25.17**	**$ 29.54**	**$ 28.92**	**$ 29.87**	**$ 31.98**	**$ 33.47**	Exhibit B-1-1, Appendix A, Schedule 4.0, line 25						
20		**Total Volume** included line losses and system use **(GWh)**		**57,910**	**55,727**	**56,859**	**57,162**	**57,187**	**58,089**	Exhibit B-1-1, Appendix A, Schedule 4.0, line 14						

*Note: includes IPP capital leases: In reviewing the Application costs related to Electricity Purchase Agreements classified as capital leases and categorised as operating costs, taxes, amortization and finances, as set out in Table 8-14 of the Application, were considered as part of Non- Heritage Cost of Energy

Cost of Energy Forecast

Energy Study models are used by BC Hydro to inform operational decisions on system storage operations, thermal dispatch, and purchases and sales of market electricity. The same models are used for BC Hydro's ongoing financial forecasting of the Cost of Energy, including the forecasts in this application.[30]

BC Hydro states that it optimizes its supply portfolio by maximizing consolidated net revenues.[31] BC Hydro further explains that "The net revenue from operations is calculated as the sum of revenue from billed sales and consolidated market electricity sales minus the sum of the cost of water rentals gas for thermal generation, Electricity Purchase Agreements and consolidated market electricity purchases… During each study, models that forecast the primary drivers of the study (inflows, market prices, Electricity Purchase Agreements deliveries and domestic loads) are run, and these provide inputs to models that represent the individual components of the generating system."[32] BC Hydro states "Regardless of the surplus or deficit in system energy, BC Hydro will shape generation into the highest priced periods available, given the flexibility of the system… BC Hydro, through its subsidiary Powerex, will then sell its surplus energy at times and in geographical markets that provide the highest value."[33]

Existing oversight

BC Hydro stated that its Energy Study models consist of a suite of proprietary in-house software developed and maintained by a specialized team within Generation Resource Management.[34] BC Hydro further explained that The Energy Studies team, working with Finance, prepares and presents a confidential report on a monthly basis which details the latest system forecast, highlighting changes in key system drivers, their effects on the forecast,

[29] Exhibit B-1-1, Appendix A, Schedule 4; Exhibit B-9-1, BCUC IR 18.2.
[30] Exhibit B-1-1, p. 4-6.
[31] Exhibit B-10, FBC IR 1.1.
[32] Exhibit B-9, BCUC IR 15.1, Attachment 1, pp. 1–2.
[33] Ibid., BCUC IR 15.3.
[34] Ibid., BCUC IR 15.1 Attachment 1, p. 1.

and variances from previous forecasts.[35] A key element of this report is a forecast of market energy purchases and sales volumes and costs and a domestic threshold purchase or sale price. This forecast must be approved by the Vice-President of Generation, or his/her delegate. In addition, the results of the Energy Study are reported on a quarterly basis to the BC Hydro Board of Directors.

3.1.1 Heritage Energy

The *Clean Energy Act* (CEA) provides the definition of "heritage assets" as follows:

a) any equipment or facilities for the transmission or distribution of electricity in respect of which, on the date on which this Act receives First Reading in the Legislative Assembly, a certificate of public convenience and necessity has been granted, or has been deemed to have been granted, to the authority or the transmission corporation under the *Utilities Commission Act*,

b) the authority's interests in the generation and storage assets identified in Schedule 1 of this Act, and

c) the authority's interests in the equipment and facilities that are for the transmission or distribution of electricity and that are identified in Schedule 1 of this Act;[36]

CEA section 2 (e) states that "to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers" as one of the British Columbia's energy objectives.

The CEA lists Heritage Assets under Schedule 1 as:

Aberfeldie	Falls River	Peace Canyon	Shuswap
Alouette	Fort Nelson	Prince Rupert	Spillimacheen
Ash River	G. M. Shrum	Puntledge	Stave Falls
Bridge River	Hugh Keenleyside Dam (Arrow Reservoir)	Revelstoke, including units 1 to 6	Strathcona
Buntzen/Coquitlam	John Hart	Ruskin	Waneta
Burrard Thermal	Jordan	Site C	Wahleach
Cheakamus	Kootenay Canal	Seton	Walter Hardman
Clowhom	La Joie	Seven Mile	Whatshan
Duncan	Ladore		
Elko	Mica, including units 1 to 6		

Directive 7, Schedule A states that:

The heritage payment obligation for any Year is the amount determined by:

(a) adding those of the following costs incurred by BCH Generation in the Year that the Commission orders may be included in the heritage payment obligation:

i. cost of energy such as the cost of water rentals and energy purchases, including purchases of gas and electricity, required to supply heritage electricity;

[35] Ibid., p. 8.

[36] *Clean Energy Act*, Section 1

ii. operating costs such as the costs of operating and maintaining the heritage resources, including an allocation of corporate costs;

iii. all costs of owning the heritage resources, including, without limitation, depreciation, interest, finance charges and other asset related expenses;

iv. all costs or payments related to generation-related transmission access required by the heritage resources, and

(b) subtracting from the sum obtained under paragraph (a) any revenues BCH Generation receives from other services provided from the heritage resources, including, without limitation,

i. revenues related to Skagit Valley Treaty obligations,

ii. revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, and

iii. revenues from the sale of surplus hydro electricity under section 5 of the Transfer Pricing Agreement.

BC Hydro submits the following as its forecast Heritage Energy:

Table 3-3: BC Hydro Forecast Cost of Energy[37]

All numbers are in GWh.	**F2017**	**F2018**	**F2019**
Hydro Electric (water rentals)	47,985	46,626	45,781
Net purchases (sales) from Powerex	-267	-263	105
Market Electricity Purchases	230	747	934
Market Purchases to Non-Heritage	0	0	0
Natural Gas for Thermal Generation	224	232	234
Surplus Sales	-4,962	-5,556	-4,517
Exchange Net	-115	-323	-354
Total	**43,095**	**41,473**	**42,182**

However, the load resource balance presented on page 3-31 of the Application in Table 3-8 shows the Heritage Energy for the F2017 to 2019 test period to be 48,445 GWh, 46,895 GWh and 46,014 GWh respectively. Schedule 4, Line 8 appears to suggest that the Heritage Energy is 43,095 GWh, 41,473 GWh and 42,182 GWh respectively (as shown in the table above). [38] BC Hydro was asked to reconcile and explain in detail how the amount of Heritage Energy is calculated and to explain why the amount of Heritage Energy forecast during the F2017 to F2019 test period does not equal to 49,000 GWh less the demand for Seattle City Light.

BC Hydro responded:

> The Heritage energy numbers shown in Table 3-8 for fiscal 2017 to fiscal 2019 are calculated by adding line 1 “Hydroelectric (water rentals)”, line 7 “Exchange net” and line 9 “Waneta (water rentals)” in Appendix A, Schedule 4.0. These Heritage energy numbers are representative of the energy expected to be generated by the Heritage system reflecting near term conditions such as

[37] Exhibit B-1-1, Appendix A, Schedule 4.0, Lines 1-8.

[38] Ibid., Appendix A, Schedule 4.0, Line 8.

reservoir elevations, generation de-rates and expected inflows. They are not meant to be directly comparable to the Heritage Energy Obligation of 49,000 GWh less the demand for Seattle City Light, which was set based on long term average conditions for the system as it existed at the time the Heritage Contract was defined.[39]

BC Hydro also states:

> The forecast for Heritage Energy in the Heritage Payment Obligation is based on 43,095 GWh, 41,473 GWh, and 42,182 GWh for Fiscal 2017, Fiscal 2018 and Fiscal 2019 test years because that is the forecasted generation from Heritage Resources required to meet the domestic load.
>
> Heritage Energy is a defined term under Direction No. 7 which was enacted on March 6, 2014. Direction No. 7 repealed Heritage Special Direction No. HC2, but continues the essential elements of the Heritage Contract framework formerly enshrined in Heritage Special Direction No. HC2. Heritage Energy means 49,000 GWh per year less the energy generated for delivery under the Skagit Valley Treaty. BC Hydro is obligated to supply from its generating resources each year the Heritage Energy, or such lesser amount of energy as may be required.
>
> The 49,000 GWh per year is based on the energy capability from the Heritage Resources under average water conditions and includes 2,365 GWh of generation from BC Hydro's thermal plants. The forecast Heritage Energy values are considerably lower than 49,000 GWh because:
>
> - Surplus Sales are subtracted from the Heritage Resource production, which is consistent with Schedule A to Appendix A Heritage Payment Obligation in Direction No. 7; and
> - Generation from thermal plants is forecast to be considerably lower than 2,365 GWh.[40]

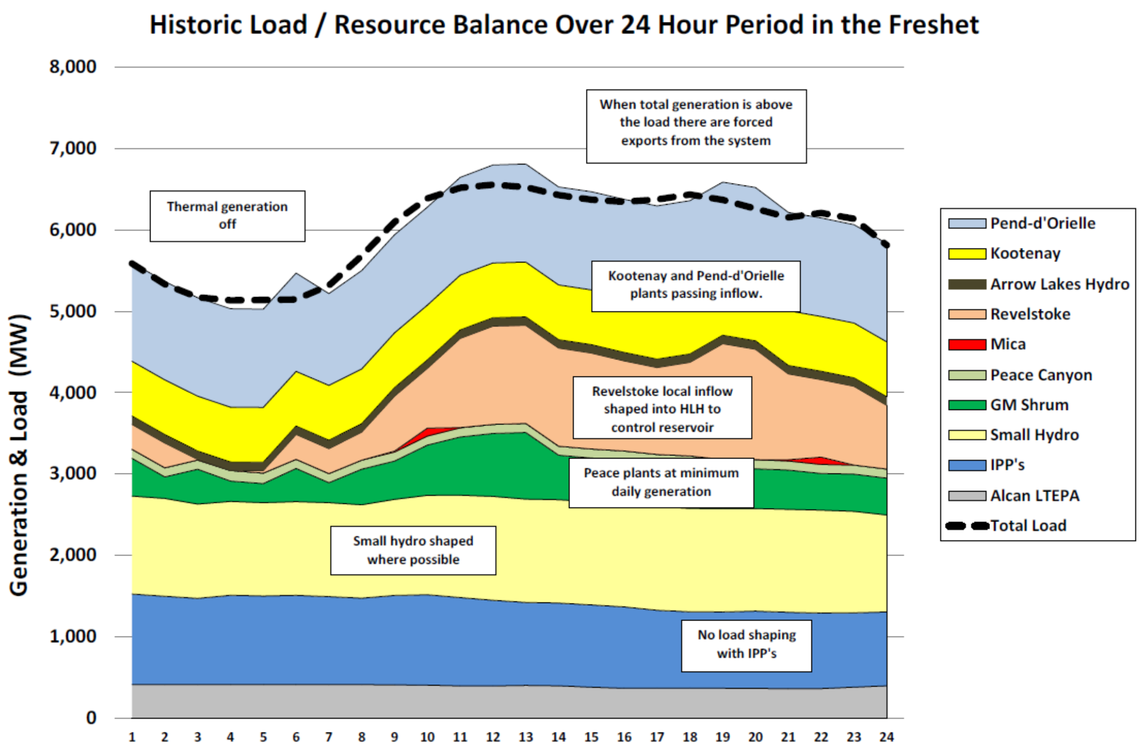
BC Hydro explains that "[h]igh surplus sales across the test period are due to a combination of initial above average system storage which results in a forecast net draw from storage of 2900 GWh in fiscal 2017 and 1170 GWh in fiscal 2018 as well as annual energy surpluses."[41] BC Hydro also notes that surplus sales are not necessarily attributable to BC Hydro energy purchases from IPPs.[42]

BC Hydro further explains that it:

> makes market purchases when energy is needed to meet load or to support system reservoirs. On the other hand, BC Hydro sells when energy is surplus to load or to reduce spill risk. As a result, surplus sales should not be considered a re-sale of market purchases because BC Hydro does not purchase market electricity above its needs with the intention of reselling it… The separation into Heritage and Non-Heritage Energy is not considered in operational decisions or in forecast modelling, but is instead an accounting allocation between Heritage and Non-Heritage Energy arising from the Heritage Contract.[43]

[39] Exhibit B-14, BCUC IR 206.1.
[40] Exhibit B-9, BCUC IR 127.2.
[41] Exhibit B-1-1, p. 4-15.
[42] Exhibit B-15, CEC IR 145.3.
[43] Exhibit B-10, CEC IR 38.2

BC Hydro elaborates that "[d]uring freshet, and at other times of low load and high river flows, generation from inflexible resources, such as wind, hydro with no reservoirs (run of river), or hydro with small reservoirs that fill quickly, can exceed the BC Hydro load in some hours. In these hours BC Hydro backs down its flexible generation as much as possible and exports any remaining surplus into the best geographical markets, or if no positive value can be achieved from this (when market prices are negative), BC Hydro will spill at certain resources to avoid generation so that it can balance generation and load without exporting at negative prices"[44] BC Hydro presents the following chart to demonstrate that IPP power has no load shaping ability:



When asked to confirm the significant burden on BC Hydro's domestic customers from BC Hydro surplus sales averaging at $23.8, $27.1 and $28.6 per MWh respectively, and at the same time BC Hydro is paying IPPs $92.3, $91.3 and $94.7 per MWh respectively, BC Hydro does not confirm, and explains:

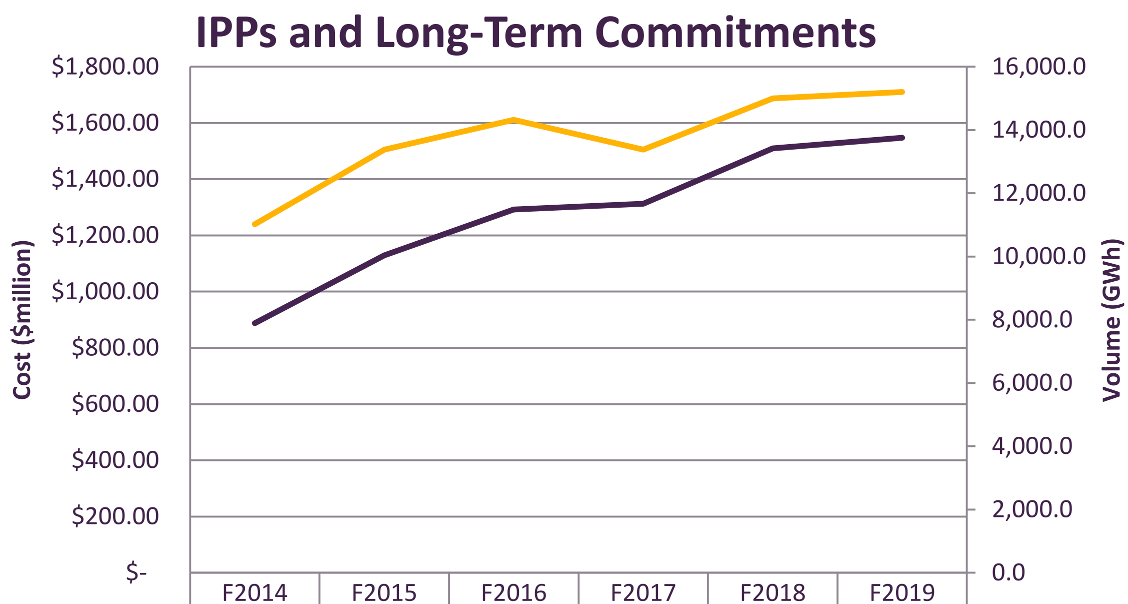
> As required by subsection 6 of the Clean Energy Act and the Electricity Self-Sufficiency Regulation, BC Hydro acquires resources to meet our obligation to be self-sufficient based on average water conditions from our heritage resources and our mid load forecast. Planning to average expected conditions will result in years in which BC Hydro has net surplus sales or net market purchases depending on a number of factors including customer loads, market prices and system conditions and constraints. Once acquired, BC Hydro and/or its subsidiary Powerex optimize the purchase and sale of electricity and natural gas in relation to BC Hydro's capabilities and domestic requirements.[45]

[44] Exhibit B-9, BCUC IR 15.3.
[45] Exhibit B-10, MoveUp 14.1.

3.1.2 Non-Heritage Energy

3.1.2.1 IPPs (including capital leases)

Figure 3-1: IPPs and Long-Term Commitments[46]



	F2014	F2015	F2016	F2017	F2018	F2019
Cost ($million)	$887.30	$1,129.3	$1,292.5	$1,312.5	$1,509.9	$1,547.8
Volume (GWh)	11,025.0	13,377.4	14,318.6	13,375.3	15,002.1	15,199.3

*Note: Certain Electricity Purchase Agreements are deemed to be capital leases for accounting purposes and are not included in the Cost of Energy, and is reflected in the "accounting adjustments" column.

BC Hydro explains that the overall increases in the Cost of Energy are driven primarily by IPP costs.[47] BC Hydro further states that on average over the test period, 97 percent of the energy purchased from IPPs relates to energy supply contracts entered into before fiscal 2017 that, pursuant to Direction No.7, the Commission must allow recovery in rates the costs associated with that energy.[48]

The increase in unit cost from IPPs over the test period is primarily attributed to an increase in the number of IPPs achieving commercial operation and delivering energy to BC Hydro during the test period. As these new resources are added, those contract prices are higher than the average, the average unit cost for the IPP portfolio will increase. Annual price escalation provisions included in Electricity Purchase Agreements also increase the unit cost to some degree.[49] The drivers of the increase in IPP costs by $237 million during the test period, including 22 projects that are expected to achieve commercial operation during the test period, is presented in the table below.[50]

[46] Table prepared using data from Exhibit B-1-1, Appendix A, Schedule 4, lines 10 and 106.
[47] Exhibit B-1-1, p. 4-9.
[48] BC Hydro Final Argument, pp. 9–10.
[49] Exhibit B-9, BCUC IR 17.2.
[50] Ibid.

Table 3-4: Costs and Volumes for Pre-COD IPPs and Long-Term Commitments[51]

Costs and Volumes for Pre-COD IPPs and Long-Term Commitments	F2017 Plan		F2018 Plan		F2019 Plan	
	Volume (GWh)	$ million	Volume (GWh)	$ million	Volume (GWh)	$ million
22 projects[1] with Electricity Purchase Agreements	601	85.2	2,106	255.6	2,383	287.8
Expected Standing Offer Program Projects[2]	71	7.8	130	13.6	291	29.2
Total before Accounting Adjustments	672	93.0	2,236	269.2	2,674	317.0
Accounting Adjustments	n/a	(16.5)	n/a	(79.4)	n/a	(80.0)
Total	672	76.5	2,236	189.8	2,674	237.0

For planning purposes, BC Hydro has assumed that 50 percent of the energy contribution from expiring biomass Electricity Purchase Agreements will be renewed, and 75 percent of the energy contribution from expiring run-of-river hydro projects will be renewed, consistent with the 2013 Integrated Resource Plan Recommended Action 4. Renewals of Electricity Purchase Agreements are subject to the review by the Commission in separate regulatory processes pursuant to section 71 of the *Utilities Commission Act*.[52]

BC Hydro submits that "[t]he Commission's determination in this proceeding as to the forecast Cost of Energy affects the variances captured in the Cost of Energy Variance Accounts during the test period, but does not affect what BC Hydro (and, ultimately, ratepayers) will pay for energy… the actual Cost of Energy is influenced by the cost of Heritage Resources and both past and future Electricity Purchase Agreements. Recovery of costs associated with existing Electricity Purchase Agreements pre-dating fiscal 2017 is mandated, and the Commission will review future Electricity Purchase Agreements, as required, in section 71 applications."[53]

BC Hydro was asked if it could contract for renewals of IPPs to match its anticipated load curves. BC Hydro responded that this approach "does not provide BC Hydro with certainty." BC Hydro further explains:

> 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

[51] Ibid., BCUC IR 17.4.
[52] Exhibit B-1-1, p. 4-22.
[53] BC Hydro Final Submission, pp. 75–76.

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.[54]

While the RRA review focuses on the test period forecast, BC Hydro, in determining the amount of energy and capacity it plans to procure from the renewal of IPP Electricity Purchase Agreements does not focus on a particular test period. Rather, BC Hydro states that it considers how a renewal will contribute to meeting long-term system need, for both energy and capacity, over the renewal contract term to determine cost-effectiveness which may, or may not, include the applicable test period.[55] BC Hydro confirmed that the currently planned actions are still appropriate given the updated Load Resource Balance, and that "any resource reduction in the near term could potentially advance the need for more costly supply in the longer term."[56]

3.1.2.2 Management of IPP Contracts

BC Hydro manages its Electricity Purchase Agreements in accordance with the terms of each specific agreement which may include the following mechanisms to allow BC Hydro to reduce its purchase commitments through provisions that: allow BC Hydro to request an IPP to reduce or cease energy deliveries for specified periods; periodically may reduce an IPP's firm energy obligations from the initial contractual obligations based on historical performance; and limit energy purchase commitments through hourly or annual caps on eligible energy.[57]

BC Hydro has executed agreements with IPPs to terminate 14 Electricity Purchase Agreements, downsize and defer two Electricity Purchase Agreements, and defer the delivery of energy to BC Hydro from an additional 11 Electricity Purchase Agreements. As a result of these actions, BC Hydro has reduced electricity purchase commitments by $2.1 billion through ongoing reductions representing 435 MW in nameplate capacity and approximately 1,890 GWh per year contracted energy through Electricity Purchase Agreement (EPA) downsizing and terminations, and one-time reductions in purchase commitments of approximately 2,050 GWh occurring between fiscal 2015 and fiscal 2018 through deferrals of commercial operations for Electricity Purchase Agreements.[58] The $2.1 billion in reduced purchase commitments is already reflected in the forecast Cost of Energy.

[54] Exhibit B-10, CEC IR 1.41.1.
[55] Exhibit B-9, BCUC IR 15.2.
[56] Exhibit B-10, CEC IR 1.32.3.
[57] Exhibit B-9, BCUC IR 17.3.
[58] Exhibit B-1-1, p. 3-42.

BC Hydro states that for future Electricity Purchase Agreements, it is also examining ways to reduce its forecasted purchase commitments. For Electricity Purchase Agreement renewals, BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. Moreover, for the Standing Offer Program and Micro-Standing Offer Program BC Hydro is going through an optimization process to ensure that they reflect future system needs, consider recent advancements in technology, and are aligned with the 2013 10 Year Rates Plan.[59]

Intervener arguments

Although BCSEA-SCBC, NIARG, and BCOAPO, addressed cost of energy in their final arguments, they have no issues with the cost of energy forecast. CEABC, MoveUp and ZoneII RPG have not raised any issues specific to the COE forecast component of the revenue requirement, however, they have requested for additional reporting from BC Hydro. CEABC requested reporting on BC Hydro revenue from sale of renewal credits, MoveUp requested the Commission to direct BC Hydro to publish all details on EPAs on its website, and ZoneII RPG requested reporting to ensure NIA communities' interest, needs and local realities are addressed. Landale and McCandless did not comment on COE.

CEC

CEC recommends that the Commission provide diligent oversight over the BC Hydro cost of energy performance and request BC Hydro to comply with orders to reduce the cost of energy in the test period and change parameters of its energy acquisition activities to avoid excess surplus risks in the future.[60]

CEC recognizes the main driver of forecast increases in the cost of IPP energy during the test period is higher cost IPP projects achieving commercial operation under EPAs that pre-date fiscal 2017 and for which cost recovery is mandated through Direction #7. It submits, however, that regardless of the existing circumstances it remains appropriate for the Commission to address the cost-effectiveness of BC Hydro's proposed future acquisitions at this time.[61]

CEC also recommends that the Commission determine that in the face of the extensive surplus on hand that BC Hydro revise its Standing Offer program to reduce actual purchase of energy and instead purchase options on the energy projects for when they will be needed; revise its IPP renewal purchase program to buy IPPs only at the expected net electricity market values or the low cost DSM values, whichever is lower; and acquire additional cost effective DSM energy as needed to avoid the costs of more expensive energy acquisition options.[62] CEC also raised issues with the benchmark price at which IPP energy are acquired, including consideration for the power supply at minimum operating costs of the IPP, market spot price for energy, and the use of long-run marginal cost.[63]

[59] Exhibit B-9, BCUC IR 17.3.
[60] CEC Final Argument, pp. 101–102.
[61] Ibid p. 78.
[62] CEC Final Argument, p. 6.
[63] Ibid., pp. 82, 89, 91.

CEC also recommends that the Commission ensure that there are appropriate criteria in place in energy purchase contracts with IPPs to avoid acquiring energy at high prices and having to sell that energy at depressed freshet prices.[64]

MoveUp

MoveUp submits that BC Hydro forecasts surplus sales to be 4,962 GWh, 5,556 GWh and 4,517 GWh for F2017, F2018 and F2019, respectively, average $23.8, $27.1 and $28.6 per MWh respectively; while at the same time BC Hydro forecasts that it must pay IPPs $92.3, $91.3 and $94.7 per MWh respectively. MoveUp "respectfully submits that the Commission should lift the veil of confidentiality from the EPAs BC Hydro has entered into and direct BC Hydro to publish all details on its website".[65]

BCOAPO

BCOAPO has no material concerns regarding the forecast cost of Heritage Energy and notes that, via the Heritage Deferral Account, the actual cost of Heritage Energy will be eventually be trued up against the forecast.[66]

No other interveners commented on surplus sales or the Heritage Energy component of COE.

BC Hydro reply

In BC Hydro's view, the majority of CEC's submission on Cost of Energy focuses on long-term resource planning issues and reasons or criteria for renewing IPP Energy Purchase Agreements.[67] CEC's submissions in this regard belong in the Integrated Resource Planning process or in section 71 filings.[68] BC Hydro will file Electricity Purchase Agreements with the Commission as required. CEC can comment on the merits of renewing an Electricity Purchase Agreement in the context of future section 71 filings.[69]

BC Hydro's submits that its balanced approach to supply acquisition is based on ensuring the delivery of reliable and cost effective electricity both in the near and long-term, while being consistent with the requirements of the *Clean Energy Act*, including the 16 energy objectives.[70] BC Hydro's energy acquisition is guided by the 2013 Integrated Resource Plan. The Recommended Actions of the 2013 Integrated Resource Plan include optimizing the existing portfolio of IPP resources and supporting the clean energy sector through renewal of Electricity Purchase Agreements and the Standing Offer Program.[71]

In response to MoveUp's submission that BC Hydro's purchase of IPP energy is costing ratepayers several million dollars per year, BC Hydro submits that it "is based on a misleading calculation that assumes all surplus energy is from IPPs. The high surplus sales during the test period are due to a combination of factors, including the initial above average system storage which results in a forecast net draw from storage of 2900 GWh in fiscal 2017 and

[64] Ibid., p. 7.
[65] MoveUp Final Argument, p. 5.
[66] BCOAPO Final Argument, p. 19.
[67] BC Hydro Reply Argument, p. 47.
[68] Ibid., pp. 47–48.
[69] Ibid., p. 52.
[70] Exhibit B-15, CEC IR 2.175.1.
[71] BC Hydro Reply Argument, p. 50.

1170 GWh in fiscal 2018 as well as annual energy surpluses. Moreover, BC Hydro plans on a long-term basis. Once resources are acquired, BC Hydro and/or its subsidiary Powerex optimize the purchase and sale of electricity in the context of the total resource portfolio. Surplus sales are therefore attributable to the resource portfolio as a whole, not solely to energy purchases from IPPs."

Commission determination

Section 5(b) of Direction 7 states that "[i]n setting the authority's rates, the commission must determine the energy required by the authority to meet its domestic service obligations and must determine the cost to the authority of the portion of that required energy that is in excess of the energy supplied under the heritage contract."

The Panel previously found BC Hydro's load forecast for the test period to be reasonable and is satisfied for the purpose of this determination the load forecast represents "the energy required by the authority to meet its domestic service obligations" for the test period. The Heritage Contract states that Heritage Energy, unless the Commission determines otherwise, is 49,000 GWh per year less the energy generated for delivery under the Skagit Valley Treaty. Energy delivered under the Skagit Valley Treaty is delivered to Seattle City Light and is forecast as 310 GWh for each of the three test years. [72] Based on the definition of Heritage Energy contained in the Heritage Contract, the Panel estimates the amount of energy that is required in excess of the energy supplied under the heritage contract as follows:

Table 3-5: Panel Calculation of Heritage and Non-Heritage Energy Required (in GWh)

	2017	2018	2019
Load Forecast (GWh)	**51,860**	**51,838**	**52,664**
Plus Line Losses (GWh)[73]	5,302	5,349	5,425
Energy Required (GWh)	**57,162**	**57,187**	**58,089**
Heritage Energy			
Base Amount (GWh)	49,000	49,000	49,000
Less: Skagit River Treaty (GWh)	310	310	310
Heritage Energy Supplied (GWh)	**48,690**	**48,690**	**48,690**
Non-Heritage Energy Required (GWh)	**8,472**	**8,497**	**9,399**

[72] Exhibit B-1-1, Appendix A, Schedule 14.0, Domestic Energy Sales and Revenue, Line 9.
[73] Ibid., Appendix A, Table 4.0, Line 15.

BC Hydro provides the following tables showing the unit costs of energy and the sources of energy supply:

Table 3-6: Unit Costs of Energy[74]

	A	B	C	D	E	F	G	H	I	J	K
1						F2014	F2015	F2016	F2017	F2018	F2019
2						Actual	Actual	Actual	Plan	Plan	Plan
3	line	**Unit Costs ($/MWh)**									
4	18			Hydroelectric (water rentals)		9.0	9.0	7.3	7.9	7.5	7.6
5	19			Waneta (water rentals)		8.3	7.0	18.7	11.9	10.8	10.8
6	20			IPPs and Long-Term Commitments		74.8	79.5	85.8	92.3	91.3	94.7
7	21			Market Electricity Purchases		45.6	28.8	22.8	37.5	40.5	38.5
8	22			Surplus Sales		(36.4)	(10.1)	(27.7)	(23.8)	(27.1)	(28.6)
9	23			Natural Gas for Thermal Generation		118.3	112.7	93.1	66.5	45.4	45.9
10	24			Non-Integrated Area		246.2	222.6	203.9	209.6	229.4	258.9
11	25			Total Weighted Cost		25.2	29.5	28.9	29.9	32.0	33.5

Table 3-7: Sources of Supply[75]

	A	B	C	D	E	F	G	H	I	J
1					F2014	F2015	F2016	F2017	F2018	F2019
2					Actual	Actual	Actual	Plan	Plan	Plan
3	line	Sources of Supply (GWh)								
4			Non-Heritage Energy							
5	9			Waneta (water rentals)	891.0	1038.5	407.2	574.7	592.8	587.4
6	10			IPPs and Long-Term Commitments	11025.0	13377.4	14318.6	13375.3	15002.1	15199.3
7	11			Mkt Purchases From Heritage	0.0	0.0	0.0	0.0	0.0	0.0
8	12			Non-Integrated Area	117.0	114.7	111.0	117.4	119.3	120.3
9	13			Total	12033.0	14530.5	14836.8	14067.4	15714.2	15907.0

Based on the unit cost of "IPPs and Long Term Commitments" shown in the table above, the Panel calculates the cost to acquire the energy needed in excess of the amount supplied under the Heritage Contract as follows:

Table 3-8: Panel Calculation of Cost of Surplus

	2017	2018	2019
Non-Heritage Energy Required (GWh)	**8,472**	**8,497**	**9,399**
Unit Cost of Non-Heritage Energy ($MWh)	**$92.30**	**$91.30**	**$94.70**
Cost of Non Heritage Energy ($mil)	**$782**	**$776**	**$890**
BC Hydro's Forecast Costs of total Non-Heritage Energy ($mil)	**$1,312**	**$1,510**	**$1,547**

The Panel has the following concerns with the BC Hydro's Forecast Cost of Energy:

1. Heritage Assets may not be providing optimal value to BC Hydro customers as anticipated in the Heritage Contract.
2. The discrepancy between the Heritage Energy forecast in the Load Resource Balance and forecast in Table 4 of Appendix A.

[74]Information extracted from Exhibit B-15, CEA IR 2.031.03, Attachment 01, RRA Appendix A Schedule 4.

[75]Ibid.

3. The accounting treatment of surplus energy costs and recoveries.
4. The cost of IPPs and Long-Term Commitment included in BC Hydro's Cost of Energy.

With regard to point one above, BC Hydro's evidence is that the variance in its calculation of Heritage Energy is due to "near term conditions such as reservoir elevations, generation de-rates and expected inflows" and not because a lesser amount of electricity is required by BCH Distribution. Further, a significant amount of energy is being sold as surplus during freshet because it is in excess of domestic load and as a result, the amount of Heritage Energy actually available is less than anticipated in the Heritage Contract.

With regard to the second item, the Panel has concerns about the way BC Hydro calculates the quantum of Heritage Energy. As previously discussed, in the load resource balance presented on page 3-31 of the Application in Table 3-8, BC Hydro showed Heritage Energy for the F2017 to 2019 test period as 48,445 GWh, 46,895 GWh and 46,014 GWh respectively. However this doesn't appear to align with the total heritage energy volumes presented in Exhibit B-1-1 Appendix A, Schedule 4.

To better understand the rate impact resulting from energy surpluses, portfolio management of the Heritage Assets, and the variances discussed above, The Panel directs BC Hydro, in a compliance filing, to provide to the Commission with the following:

i. **A reconciliation of the calculation in Exhibit B-1-1 Appendix A, Schedule 4 with the forecast Heritage Energy in Table 3-8 of the 2013 IRP. A detailed schedule, by year, of the actual Heritage Energy delivered to BC Hydro distribution in each of the last 10 years;**
ii. **A breakdown of the Net Purchases (sales) from Powerex line item within the Heritage Energy section of Exhibit B-1-1, Appendix A, Schedule 4 into gross volumes;**
iii. **A description of the items included in each category contained in the Heritage Energy section of Exhibit B-1-1, Appendix A, Schedule 4, particularly including a description of the items included in "Surplus Sales," as well as gross volumes from Powerex, per ii) above;**
iv. **A discussion of whether actual energy delivered for distribution by Heritage Assets has been reduced below availability in any way due to energy supplied by IPP energy;**
v. **A thorough explanation of the amount of Heritage Energy that is deliverable and expected to be delivered in each of the next 5 years and, if appropriate, a description of how this varies from actual historical deliveries;**
vi. **A thorough discussion of whether the generating abilities of any Heritage Assets have been impaired or reduced in any way; and**
vii. **A recommendation regarding whether the definition of Heritage Energy in the Heritage Contract should be revised pursuant to Section 8 of the Heritage Contract.[76]**

With regard to the fourth point, we have reviewed BC Hydro's explanation of optimizing the supply portfolio by maximizing the consolidated net revenue as explained in Exhibit B-10, FEI IR 1.1.1 and find that further information is required. **Therefore we direct BC Hydro to explain in its compliance filing the accounting**

[76] Section 8 states that the Commission may, by Order, modify one or both of the definitions of "heritage energy" and "heritage payment obligation" if the Commission is satisfied that a change in circumstances has permanently affected (i) the capability of the heritage resources to provide one or both of capacity and energy, or (ii) the authority's cost of generating the heritage energy.

treatment of surplus energy costs and recoveries. Specifically, BC Hydro is to provide the Commission with a detailed accounting policy for treatment of surplus energy that explains how recoveries are calculated and recorded, the treatment of costs for under-utilized assets and/or any take or pay arrangement that exist with IPP's, and any other relevant details to describe how costs resulting from surplus energy are offset by recoveries for that energy.

Further, to demonstrate how these policies are applied to BC Hydro's accounts, the Compliance filing should include an annual analysis, for the last 5 years, that quantifies the value of actual surplus energy purchased above domestic consumption. To the extent the surplus energy is purchased from IPPs, the analysis should include relevant formulas and should note any recoveries, broken down by categories such as penalties or transfers. A description should be included to support how such amounts are determined in accordance with the accounting policy described above.

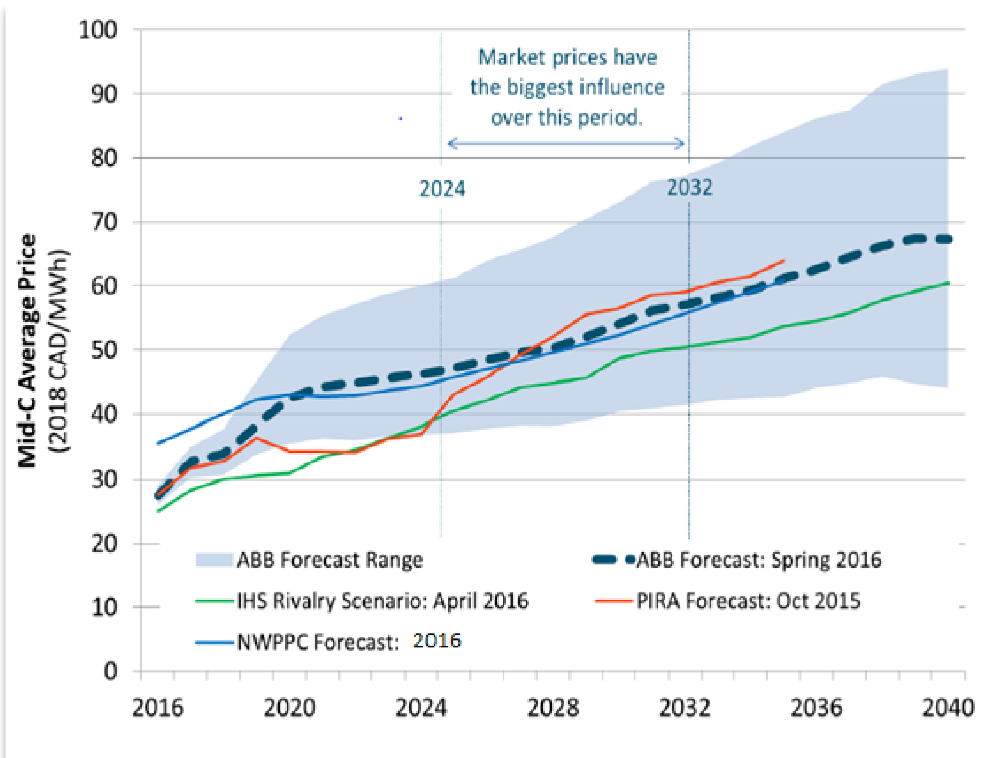
With regard to the fifth point listed above, we note that the unit cost of IPPs and Long-Term Commitments is the second most expensive resource on BC Hydro's resource stack, after the resource for Non-Integrated Area. On the other hand, the gains from surplus sales per unit are lower than the total weighted cost of the energy portfolio in each of the test years. The Panel also notes that the lack of load shaping with IPPs during freshet periods contributes to the need for surplus sales to mitigate spill risk and when energy exceeds load. The Panel observes that there is potential for cost savings if additional IPP contracts are canceled or amended to reduce IPP purchases. The Panel acknowledges BC Hydro's obligation to meet self-sufficiency requirement as per section 6 of the CEA.

The Panel has concerns about the high unit costs of BC Hydro's portfolio of IPP purchases – regardless of how the calculation of Heritage Energy is made – and we are of the view that careful consideration be given to the need for and length of renewals. The Site C Report identified the effect of disruptive technologies on the price of renewable energy – driving it down faster than previously predicted - and the downward pressure on the forecast prices of energy in Western North America. Given these trends, the view expressed by BC Hydro that "[t]he 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 green-field energy resources" may need to be reconsidered. The evidence in the Site C Inquiry demonstrates a significant downward trend in the cost to acquire clean, renewable energy. In the Site C Inquiry, BC Hydro stated that it estimated prices for 2024 to 2030 short-term energy sales to be in the CAD $48/MWh range. BC Hydro explained that electricity markets are currently over built but are returning to a more balanced position, but acknowledges this recovery may take some time as clean energy subsidies and Renewable Portfolio Standards continue to create a surplus in the market.[77]

[77] Site C Report, p. 88.

In the Site C Inquiry, the Commission considered the following forecasts:

Figure 3-2 : Mid-C Average Price Forecasts



In the Site C Inquiry, the Commission concluded the following:

> Given the current low market prices and the likelihood of increasing supply, the Panel is persuaded that a conservative approach for the estimation of future market pricing is warranted and finds that BC Hydro's proposed Mid C forecast should not be relied upon. Accordingly, the Panel finds that for the purposes of this assessment the future market price for 2024 and beyond should be considered to be at a point mid-way between BC Hydro's proposed Mid C forecast and the low end of the ABB range. Given the current low market prices and the likelihood of increasing supply, the Panel is persuaded that a conservative approach for the estimation of future market pricing is warranted and finds that BC Hydro's proposed Mid C forecast should not be relied upon. Accordingly, the Panel finds that for the purposes of this assessment the future market price for 2024 and beyond should be considered to be at a point mid-way between BC Hydro's proposed Mid C forecast and the low end of the ABB range.[78]

We note that BC Hydro is forecasting selling surplus energy at an average unit price of $23.8/MWh which is consistent with the above data and conclusions. However its forecast average cost of acquisition for IPP power over the test period of approximately $93/MWh is considerably higher. However, as stated above, the Panel acknowledges that because of BC Hydro's self-sufficiency obligations under the Clean Energy Act, it is restricted in the amount of energy it can access at Mid C and therefore at Mid C prices.

[78] Ibid., p. 95.

As specified in *the Clean Energy Act*, the Minister has jurisdiction over BC Hydro's long term resource planning through the Integrated Resource Plan (IRP) process. BC Hydro is scheduled to complete its next IRP in 2018. The Panel agrees with BC Hydro with regard to the submissions of CEC that focus on long term resource planning issues. These issues do belong in the IRP process. Further, CEC's submissions regarding the price of IPP renewals belong in the Commission's IPP renewal process. Therefore, we make no determinations on these issues at this time. However, we provide some recommendations that may be helpful in BC Hydro's next IRP review.

The Panel recommends that in the 2018 IRP process, BC Hydro's approach to optimizing its portfolio is reviewed. Further we recommend that BC Hydro consider the timing of its existing IPP contracts and contract renewals. In particular, it would benefit ratepayers if the timing of the delivery of energy was more aligned with BC Hydro's forecast load, after allowing for the Heritage Energy.

The Panel also recommends a review of the appropriateness of five years between refreshes of the IRP. Five years can be a long time - prices for clean energy have dropped significantly during the five years since the previous IPP review and also BC Hydro's demand has also fallen short of the previously forecasts. Many utilities update their long term resource plans on a more frequent basis and/or review their supply portfolio annually. For example, in BC, Fortis Energy Inc., a gas utility of comparable size to BC Hydro submits its Annual Contracting Plan to the Commission. FortisBC Inc., BC Hydro's counterpart in the southern interior also files its Annual Electric Contracting Plan with the Commission.

Regardless of the amount of time between IRP reviews, given the speed of technological advancements and possible changes in the policy environment in which BC Hydro operates, it is important to monitor and adjust the planning process in accordance with the external environment in periods between the review processes. The Panel recognizes the $2.1 billion in reduced purchase commitments that BC Hydro has already achieved. However there remains a significant amount of additional surplus energy acquisitions. It is in neither the Utility's nor the Ratepayer's interests to follow a plan that was approved at a time when circumstances were materially different. In this regard we note that BC Hydro has responded to changes in the environment and has modified its approach to demand side management.

3.2 Operating costs

With respect to the operating cost component of its revenue requirements, BC Hydro uses the term *base* operating costs to reflect the expenditures incurred in its day to day operations.[79] *Base* operating costs are net of regulatory account transfers and provisions and do not include costs related to Independent Power Producer (IPP) capital leases or ineligible capital overhead under International Financial Reporting Standards (IFRS). BC Hydro's explains that IPP's capital leases are affected by new electricity purchase agreements and are excluded because accounting rules may vary from year to year. BC Hydro states IFRS ineligible overhead is a credit to operating costs which is phased in over a 10-year period and therefore excluded from operating costs.

BC Hydro explains that its "base operating expenditures (excluding Smart Metering and Infrastructure Program costs which were previously deferred while the project was in implementation and are now being

[79] Exhibit B-1-1, p. 5-18.

operationalized as the Program is complete), are forecast to increase by $11.7 million in fiscal 2017, $2.1 million in fiscal 2018 and $11.9 million in fiscal 2019, averaging approximately 1.2 per cent per year over the test period."[80]

Base operating costs are set out in the following table:

Table 3-9: Base Operating Costs during the Test Period[81]

		F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Base Operating Cost (Table 5-5 Chapter 5)	A	**712.7**	**746.5**	**747.2**
Test Period Savings/Efficiencies	B	**(33.2)**	**(0.3)**	**(0.2)**
Test Period Cost Increases				
Unavoidable Costs		10.1	7.6	9.3
Capital-Driven		19.0	(3.1)	2.6
Initiatives		6.5	(1.5)	
Other Cost Pressures		9.3	(0.6)	0.2
Total Test Period Cost Increases	C	44.9	2.4	12.1
Net Increase/(Decrease) Excluding Smart Metering and Infrastructure - Operationalized Cost Net of Savings	D=B+C	11.7	2.1	11.9
Total Percentage Increase Excluding Smart Metering and Infrastructure - Operationalized Costs Net of Savings (%)	D/A	**1.6**	**0.3**	**1.6**
Smart Metering and Infrastructure	E	22.1	(1.4)	(0.1)
Net Increase/(Decrease) Including Smart Metering and Infrastructure - Operationalized Cost Net of Savings	F=D+E	33.8	0.7	11.8
Base Operating Costs	G=A+F	**746.5**	**747.2**	**759.0**
Total Percentage Increase Including Smart Metering and Infrastructure - Operationalized Costs Net of Saving (%)	G/A	**4.7**	**0.1**	**1.6**

BC Hydro explains various cost drivers trigger increases and decreases over the test period. BC Hydro categorizes these cost drivers as:

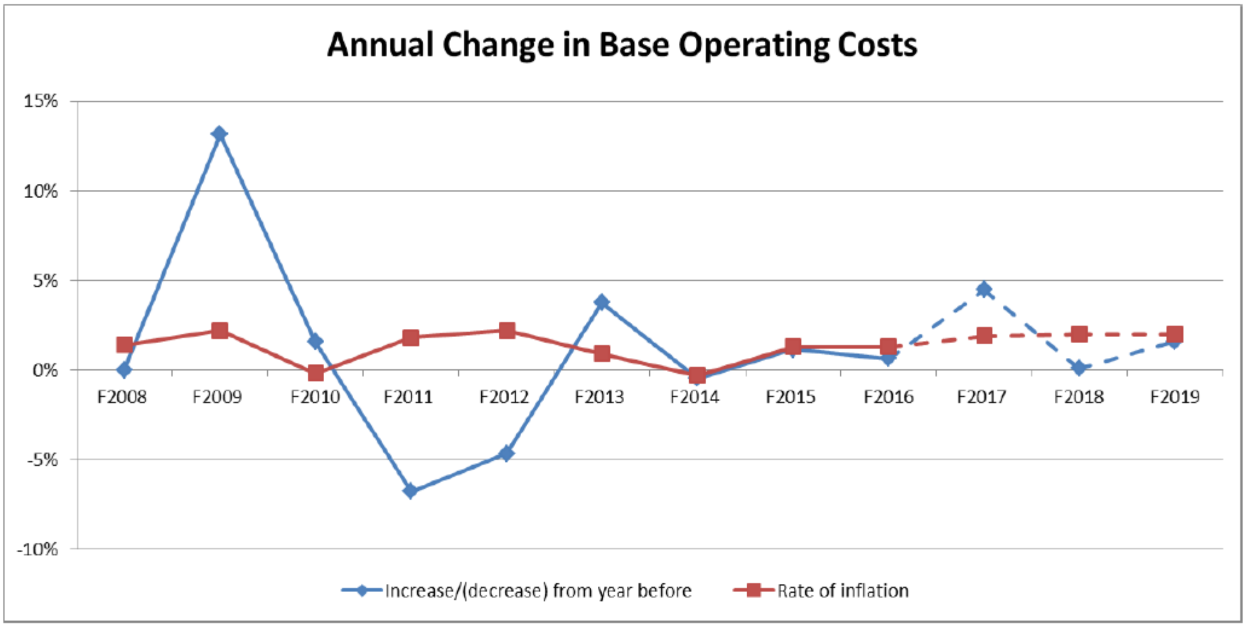
1. unavoidable costs (costs arising from external regulators and collective agreements);
2. capital driven costs (project investigation and maintenance);
3. initiatives (safety and customer service strategy); and
4. other cost pressures (including storm restoration, and investments in technology).

[80] Ibid., p. 5-1.

[81] Ibid., Table 1-1, p. 1-23.

BC Hydro reports that average annual increases in base operating costs from fiscal 2013 through fiscal 2016 were 1.8 percent per year.[82] For the test period, BC Hydro stated that it has undertaken a full review of its base operating costs and as a result, cost increases will be held below the rate of inflation[83] at an average rate of 1.2 percent per annum over the test period, as noted above. This is illustrated in the Figure below:

Figure 3-3: Annual Change in Base Operating Costs[84]



BC Hydro reports savings and efficiencies in F2017 of $33.2 million, which will continue throughout the test period, with further additional savings in F2018 and F2019 which are a result of the Company's efforts to manage its operating costs.[85] BC Hydro submits that $15 million of the $33.2 million in annual savings is attributed to an efficiency initiative in the Transmission, Distribution and Customer Service Business Group which resulted in the identification of over 20 projects addressing a number of themes, including inspections frequency optimization, vegetation management tools implementation and trouble response process improvements.[86] A further $7 million out of the $33.2 million is related to the partial decommissioning of the Burrard Thermal Plant and its conversion to operating as a synchronous-condense facility, and $6.9 million is related to savings in various areas including consultants, donations and sponsorships. Finally, BC Hydro submits that $4.3 million in company-wide savings from ongoing efforts to find cost savings and efficiencies are planned within the $33.2 million savings.[87]

Prior to the test period, BC Hydro submits by March 2014 that it implemented all 50 recommendations from the July 2011 Government Review report recommendations, "including reducing operating costs by $391 million

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[82] Ibid., p. 5-1.
[83] Exhibit B-14, BCUC IR 193.0.
[84] Ibid., BCUC IR 219.1.
[85] Exhibit B-1-1, p. 5-20; Exhibit B-10, BCOAPO IR 31.1.
[86] Ibid., pp. 5-20, 5-61.
[87] Ibid., p. 5-20.

over a three-year period."[88] BC Hydro states that these savings were reflected in the Fiscal 2012 - Fiscal 2014 Amended Revenue Requirements Application, and included "workforce reductions, savings from efficiency projects, and reductions in consultants and contractors, travel, and various other reductions."[89]

Intervener arguments

BCOAPO acknowledges BC Hydro's planned savings for 2017 of $33.2 million[90] but submits that the Commission should reduce BC Hydro's revenue requirement as it relates to operating costs by the following amounts:

- $5 million in each of F2017, F2018, and F2019 with respect to safety initiatives;[91]
- $3 million in F2017 and $2 million in each of F2018 and F2019 with respect to Smart Metering and Infrastructure (SMI) meter reading costs;[92]
- The operating costs of business groups other than the Transmission, Distribution and Customer Service which, cumulatively, found no more than $0.3 million in cost savings efficiencies in F2017 and recognize savings that will arise from the continuation of BC Hydro's Work Smart initiative in F2018 and F2019;[93] and
- $3.6 million in F2017, $1.7 million in F2018, and $0.8 million in F2019 with respect to First Nations negotiations costs.[94]

Based on these observations, BCOAPO submits that the total requested reduction in operating costs is between $14 million and $15 million in F2017,[95] and a further $9 million in F2018 and $8 million in F2019.[96]

Zone II raises concern over BC Hydro's use of local contractors, the need to upgrade the customer handbook, communications available for remote communities and the handling of security deposits in Tsay Keh Dene[97] and requests the Commission to instruct BC Hydro to reduce operating costs by $20 million per year for each of the test period. [98]

NIARG is generally supportive of BC Hydro's proposed operating costs, but submits that the goal of providing "better information to customers" has not yet been achieved in the non-integrated areas (NIAs) due to the limitations in the wireless network infrastructure required for Smart Meters to function as designed. NIARG asks the Commission to direct BC Hydro to address these concerns as part of its ongoing business and in the context of the Module 2 Rate Design filing.[99]

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[88] Ibid., p. 1-14.
[89] Exhibit B-9, BCUC IR 34.2.
[90] BCOAPO Final Argument, p. 24.
[91] Ibid., p. 27.
[92] Ibid., pp. 25, 27.
[93] Ibid., p. 27.
[94] Ibid., pp. 26, 28; F2017 calculated as $5.6 million forecast - $2 million maximum = $3.6 million proposed reduction to forecast. F2018 calculated as $3.7 million forecast – $2 million maximum = $1.7 million proposed reduction to forecast. F2019 calculated as $2.8 million forecast - $2 million maximum = $0.8 million proposed reduction to forecast.
[95] BCOAPO Final Argument, p. 26.
[96] Ibid., p. 28.
[97] Zone II Final Argument, pp. 15–20.
[98] Ibid., p. 20.
[99] NIARG Final Argument, p. 15.

CEC comments on the rising costs of the operations support group, raising specific concerns over the supply chain and related financial support group.[100] However, CEC does not request specific reductions, instead CEC recommends BC Hydro "establish a target for strategic facilities outage factor."[101]

BCSEA indicates they take no issue with the operating costs as proposed. AMPC supports BC Hydro's proposed operating costs.[102] CEABC, Landale, MoveUp and McCandless take no position on operating costs.

BC Hydro Reply

BC Hydro responds stating that BCOAPO's "submissions provide no valid basis upon which to modify BC Hydro's forecast operating expenses."[103] BC Hydro argues that smart metering sustainment costs are no longer being deferred, are not new costs and that BCOAPO is incorrect in concluding these are adding to overall costs. BC Hydro further asserts that:

- no offsetting savings are available to justify a reduction in safety initiative costs;[104]
- savings on meter reading costs have been properly reflected;[105]
- savings from company-wide efficiency initiatives are correctly forecast;[106]
- Work Smart benefits have been properly reflected as the intent of these costs not do reduce costs, but rather allow the company to reallocate its staff to more productive purposes; and
- First Nation negotiation costs are properly forecast because they can fluctuate from year to year.[107]

In response to Zone II, BC Hydro states the proposal to reduce operating costs by $20 million for each test year is based on mistaken assumptions regarding the use of contractors, and is reliant on "statistical information that provides no meaningful insight into BC Hydro's performance."[108]

Regarding NIARG's requests, BC Hydro notes that it is not responsible for cellular network upgrades, and sets out the steps it is taking to improve service in non-integrated areas.[109] BC Hydro states that NIARG regarding dealing with service issues in the context of the next rate design filing is not required and that it is beyond the jurisdiction of the Commission to direct changes to the management of the utility.[110]

BC Hydro responds to CEC noting that setting a single forced outage factor is impractical and that each facility must be assessed separately.[111] BC Hydro challenges CEC's statements regarding operations support cost growth

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[100] CEC Final Argument, pp. 111, 118, 129.
[101] Ibid., pp. 116, 117.
[102] AMPC Final Argument, p. 1.
[103] BC Hydro Reply Argument, p. 60.
[104] Ibid., p. 62.
[105] Ibid., p. 62.
[106] Ibid., p. 62.
[107] Ibid., p. 65.
[108] Ibid., p. 73.
[109] Ibid., p. 72.
[110] Ibid., p. 73.
[111] Ibid., p. 65.

indicating that the primary drivers of increased costs are as a result of IFRS ineligible capital overhead now included in operating costs, the impact of IPP capital lease costs, increases in standard labour rates and other specifically supportable costs.[112]

Commission determination

Given the limitations on the Commission's discretion because of the current regulatory framework as outlined in section 2.2 of this decision, a key area of focus for the Panel is BC Hydro's base operating costs. The Panel notes that BC Hydro states that test period increases in base operating costs are forecast to be below the rate of inflation[113] at an average of 1.2 percent per annum (excluding Smart Metering and Infrastructure Program costs).[114] The Panel recognizes that in some cases, comparing forecast cost increases to the rate of inflation may be considered an appropriate measure for evaluating the reasonableness of forecast cost increases in the test period. This method is likely suitable in situations where a regulator has consistently been empowered to oversee all aspects of the utility's forecast and historical expenditures through proceedings in which the underlying base costs were initially established. However, given the Commission's limited involvement in the approval of BC Hydro's recent revenue requirements, the Panel does not have a high degree of comfort in BC Hydro's starting point, being the 2016 base operating cost.

Accordingly, the Panel is not convinced that an annual increase commensurate with inflation is a solid reason for supporting the reasonableness of forecast costs in the test period. The Panel notes that the 2011 review indicated that BC Hydro "is focussed on justifying its costs through incremental rate increases rather than employing a zero-based operating budget development methodology to understand its underlying cost structure."[115] The Panel cannot conclude BC Hydro had used a zero based budgeting methodology when estimating costs proposed in this Application.

The Panel notes that the 2011 Review contained specific recommendations regarding BC Hydro's operating costs, which BC Hydro states have now been fully implemented.[116] BC Hydro also states it has completed a base budget review, taken steps to limit cost increases, initiated new programs to improve outcomes and gain capacity and restructured operations.[117] Given that the Commission was not involved in the 2011 review, the Panel makes no findings towards BC Hydro's efforts in this regard.

The Panel recognizes that there will be a "comprehensive review of BC Hydro that is expected to begin in fiscal 2018 and is likely to be completed in fiscal 2019."[118] Accordingly, the Panel is reluctant to make any adjustments to BC Hydro's operating costs at this time other than to note that reducing operating costs is one of the few steps BC Hydro can take to reduce it revenue requirements with immediate effect. Therefore the Panel approves the forecast operating costs for the test period.

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112 Ibid., pp. 66–68.
113 Exhibit B-14, BCUC IR 193.0.
114 Exhibit B-1-1, Table 5-5, p. 5-19.
115 Review of BC Hydro, June 2011, p. 20.
116 Exhibit B-1-1, p. 1-14.
117 Ibid., pp. 1-2-1-3.
118 Exhibit B-23, p. 3.

In its review of BC Hydro's operating costs, the Panel has identified a number of areas of concern and recommends these areas be included in the government's upcoming review. The Commission may also perform its own investigation of these and other areas in future revenue requirement applications:

1. BC Hydro has made and plans to invest in various technology assets and emerging technology pilot programs in a number of priority areas over the next five years.[119] While IT Investments are necessary for organizations to provide the right tools to support business functions, there should be a sound business case developed to support the investment with stated financial measurements such as NPV analysis ROI, or some other life cycle cost analysis. The Panel is unclear on whether these analyses were performed by BC Hydro and is unable to assess how technology investments will result in into quantifiable efficiencies and cost savings in other operational areas.

2. In the 2011 review of BC Hydro, it was recommended that there be a reduction of staff from the current 6,000 employees to 4,800.[120] In the Application, BC Hydro indicated it had net reduction of approximately 650 positions[121] in response to the 2011 review recommendations. However at this time, BC Hydro indicates it still has over 5,500 employees[122] and estimates total full time equivalent (FTE) staffing at 6,296 in 2017, 6,344 in 2018 and 6,365 in 2019.[123]

3. BC Hydro initiated a Work Smart program which uses Lean methodology to examine internal processes for opportunities to make them more efficient.[124] BC Hydro states these initiatives were implemented across the organization and are reported to have generated an estimated additional employee capacity of 22,550 hours annually.[125] Given these initiatives, in the Panel's view it should be expected that further efficiency savings should be identifiable in an organization as large as BC Hydro and that there should be incremental cost savings in F2018 and F2019. However, the Panel notes that BC Hydro states that it has not completed a cost benefit analysis for the initiatives[126] but instead will monitor as it is rolled out to evaluate its effectiveness.[127] The Panel recognizes that while BC Hydro states that it is not the intention of Work Smart to reduce costs but rather to allow for the reallocation of staff to more productive purposes, in our view a measured increase in productivity should result in costs savings.

4. In July 2015, BC Hydro launched the Workforce Optimization Program to examine its resourcing model to determine the right mix of internal and external resources. BC Hydro submits that increased labour costs are supposed to be more than offset by a reduction in capital labour costs associated with contractors.[128] Although BC Hydro reported the elimination of 900 positions,[129] its Workforce Optimization will actually add additional 170 FTE's through to F2019.[130] Although short-term savings are

[119] Exhibit B-1-1, Appendix O.
[120] Review of BC Hydro, June 2011, p. 6.
[121] Exhibit B-1-1, p. 1-14.
[122] Ibid., p. 1-34
[123] Ibid., Exhibit B-9, BCUC IR 41.4.
[124] Ibid., p. 1-25.
[125] Ibid., p. 1-36; Exhibit B-9, BCUC IR 32.4.1.
[126] Ibid., BCUC IR 31.3.
[127] Ibid., BCUC IR 32.4.1.
[128] Exhibit B-9, BCUC IR 33.3.
[129] Exhibit B-1-1, p. 5-15.
[130] Ibid., p. 5-16; Exhibit B-9, BCUC IR 35.4.1 and 1.35.5.

anticipated by BC Hydro,[131] there does not appear to be an assessment of the long-term effects and costs of hiring contractors as employees. Additional concerns related to an increasing workforce are also stated in #2 above.

5. BC Hydro states that based on its 2015 survey, salaries for electric utility jobs are 15 percent below market rates and general industry jobs as at market. On a total cash (salary plus short term incentives pay) basis, electricity utility jobs are 25 percent below market rates and general industry jobs are 7 percent below market rates.[132] To compensate, BC Hydro states that it provides benefits such as time off and the pension program to reduce the gap to market on a total rewards basis. The Panel notes that both the costs and benefits of these initiatives are unclear and should be further examined.

3.3 Capital costs

The context for the Panel's review of the forecast capital expenditures and additions for the test period is to find whether or not the forecasts are reasonable for use in the three-year test period in order to determine if the approvals sought comply with sections 59–60 of the UCA as well as the other elements of the legislative framework as summarized in Section 2.2 of the decision.

In Chapter 6 of the Application, BC Hydro details its planned capital expenditures and expected capital additions during the test period. BC Hydro submits the Commission should find that the forecast capital expenditures and additions forecast for the test period are appropriate as follows:

1. The capital forecast is the product of a well-defined planning process that considers system requirements, strategic priorities and rate impact;
2. BC Hydro is investing to meet reliability, safety and customer requirements while at the same time it is reducing expenditure and additions to help keep rates as low as possible;
3. BC Hydro has appropriate organizational structures, processes and oversight to deliver its capital plan on budget.[133]

BC Hydro states that its forecast capital expenditures and additions for the test period both reflect reductions of almost $400 million, in response to the reduced rate of forecast load growth and that as a result of the capital reductions and BC Hydro's other efforts, on track to meet the 2013 10 Year Rates Plan rate targets and make necessary capital investments. The Attachment to BC Hydro's response to BCUC IR 73.1 listed and described all projects greater than $20 million (greater than $5 million for Information Technology projects) that had been part of the initial capital investments but were delayed or cancelled to achieve the $400 million reduction. BC Hydro submits that it achieved the reductions in expenditures and additions primarily by delaying, not cancelling, investments.[134]

[131] Exhibit B-1-1, p. 5-16.
[132] Exhibit B-10, CEC IR 49.5.
[133] BC Hydro Final Argument, p. 148.
[134] Ibid., pp. 127–128.

Based on its review of the evidence and considering the arguments of the parties, the Panel has identified the following key issues to be addressed in its findings on the reasonableness of the forecast capital expenditures and additions for the three-year test period:

1. Forecast capital additions

Capital expenditures placed into service become capital additions resulting in the amortization and financing costs included in BC Hydro's revenue requirements and as such the Panel considers it appropriate to first assess the reasonableness of capital additions;

2. Planned capital expenditures

The Panel will then review BC Hydro's large prospective projects to determine if there are potentially significant public interest issues that require further investigation through separate certificates of public convenience and necessity (CPCNs) for these projects; and

3. Intervenor issues

The Panel then considers issues CEABC and CEC raise with respect to specific planned projects and as well as CEC's concern with BC Hydro's track record related to project delivery. The Panel also addresses Landale's issue regarding Burrard depreciation rates.

3.3.1 Forecast capital additions

Forecast capital additions for 2015, 2016 and those expected in the test period are set out in the following table:

Table 3-10: BC Hydro Actual and Planned Growth and Sustaining Capital Additions[135]

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Generation							
Growth	298.4	293.4	298.7	245.4	26.6	0.9	0.2
Sustaining	314.8	189.7	305.6	289.0	486.4	386.2	1,332.0
Transmission & Distribution							
Growth	1,313.3	1,137.9	1,627.0	1,486.8	581.9	472.8	442.8
Sustaining	330.0	340.5	400.3	431.5	437.4	374.6	429.0
Business Support							
Technology (Schedule 13, Line 45)	113.7	82.3	103.0	145.2	81.6	91.1	112.6
Properties (Schedule 13, Line 53)	113.4	83.6	92.4	160.9	68.3	118.1	25.5
Fleet / Other (Schedule 13, Line 56)	28.0	26.5	35.2	23.7	55.3	46.1	45.7
Total	2,511.6	2,153.8	2,862.2	2,782.6	1,737.6	1,489.9	2,387.8
Less: Contribution in Aid	(162.7)	(333.2)	(129.3)	(110.9)	(89.8)	(88.0)	(84.4)
TOTAL	2,348.9	1,820.6	2,732.9	2,671.7	1,647.8	1,401.9	2,303.4

[135] Exhibit B-1-1, p. 6-7.

BC Hydro states that the existing Capital Additions Regulatory Account and the Total Finance Charged Regulatory Account capture the effect of higher or lower than forecast amortization of capital additions in a given year and the result is these variances are recovered in future rates. BC Hydro proposes to continue using these accounts.

BC Hydro explains that test period actual capital additions can be expected to vary from forecast due to updated in-service dates.[136]

BC Hydro submits its forecast additions for the test period are reasonable and should be approved.[137]

Intervener arguments

With the exception of CEABC and CEC, interveners are satisfied or raise no issues with respect to BC Hydro's expenditures or additions. The issues CEABC and CEC raise with respect to specific planned projects and related to project delivery are addressed in section 3.3.3 below.

Commission determination

The Panel finds BC Hydro's forecast capital additions reasonable for the F2017 to F2019 test period. In the Panel's view, BC Hydro has provided sufficient evidence to support the reasonableness of its forecast capital additions for the test period.

The Panel recognizes that some variation in the timing of capital expenditures in a given year is to be expected and that such variances are captured in regulatory accounts so the only impact of actual additions are built into rates. This is further supported by the fact that in F2015 and F2016, BC Hydro's forecast additions were higher than actual which would have resulted in lower actual amortization for the periods and this variance would have been appropriately captured in the related variance regulatory accounts.

3.3.2 Planned capital expenditures

In this section, the Panel reviews BC Hydro's large planned projects to determine if, in addition to assessing the reasonableness of capital expenditures to the extent such expenditures impact the F2017 to F2019 revenue requirement (through capital additions), there are potentially significant public interest issues that require further investigation through a separate certificate of public convenience and necessity (CPCN) application and review process.

Planned capital expenditures for 2015, 2016 and those expected in the test period are set out in the following table:

[136] BC Hydro Final Argument, p. 147.
[137] Ibid., p. 83.

Table 3-11: BC Hydro Actual and Planned Growth and Sustaining Capital Expenditures[138]

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Generation							
Growth (Schedule 13, Line 4)	116.1	108.0	71.2	61.2	20.0	2.4	0.7
Growth - Site C Clean Energy (Schedule 13, Line 15)	-	25.2	-	489.4	742.5	716.5	829.2
Sustaining (Schedule 13, Line 5)	516.5	418.2	535.7	436.8	530.0	534.0	424.3
Transmission & Distribution							
Growth	972.2	1,029.0	679.8	607.4	641.8	455.4	402.2
Sustaining	357.6	332.4	421.4	427.5	440.5	486.4	561.6
Business Support							
Technology (Schedule 13, Line 19)	164.1	115.2	109.3	122.3	83.9	93.4	78.8
Properties (Schedule 13, Line 22)	96.3	83.9	85.1	78.8	95.7	75.0	88.3
Fleet / Other (Schedule 13, Line 25)	29.7	47.9	36.6	72.5	49.7	48.6	39.6
Total	2,252.5	2,159.8	1,939.2	2,296.0	2,604.0	2,411.8	2,424.6
Less: Contribution in Aid	(85.1)	(333.9)	(124.1)	(135.5)	(86.4)	(100.2)	(106.4)
TOTAL	2,167.4	1,825.9	1,815.1	2,160.5	2,517.6	2,311.6	2,318.2

Currently, BC Hydro's internal "Capital Project Filing Guidelines" (Guidelines) wherein BC Hydro established three different expenditure threshold levels for capital projects:

- $100 million for generation and transmission (including Substation Distribution Asset (SDA) components) projects;
- $50 million for distribution and building projects; and
- $20 million for information technology and telecommunication (IT&T) projects. [139]

BC Hydro submits, that where it deems appropriate, it may also file applications with the BCUC for capital projects below these expenditure threshold levels.

BC Hydro also states that:

1. It will follow its Guidelines and will continue to do so until it is changed. BC Hydro expects new Guidelines as an outcome of the Capital Projects and Expenditures proceeding.
2. Non-financial CPCN criteria should not be used to trigger a CPCN application.
3. BC Hydro will file either a CPCN or a section 44.2 application for projects that exceed the Guidelines thresholds. CPCN applications will be made for extensions that exceed the thresholds. For all projects that meet the expenditure thresholds, but do not meet the definition of extension as described above, BC Hydro will file an expenditure schedule for acceptance under section 44.2.

[138] Exhibit B-1-1, p. 6-6.
[139] Exhibit B-9, BCUC IR 66.1.

4. Extensions are not defined in the UCA, however, a definition may be an outcome of the Capital Projects and Expenditures proceeding.
5. The Commission always retains discretion to order that a CPCN is required for a project regardless of thresholds set in advance. Therefore, the Commission can always require a CPCN in the unusual situation where it perceives that a lower-cost project warrants the process. [140]

Commission determination

Capital spending directly affects finance charges and amortization, and indirectly affects operating costs. As such, capital spending is one of the largest factors affecting BC Hydro's revenue requirement.

Notwithstanding BC Hydro's position on when it perceives it necessary to file a CPCN, the Panel retains its legislative mandate under section 45(5), where appropriate. The Panel reviews large planned projects to identify projects that have potentially significant public interest issues requiring further investigation through separate CPCN review processes. Based on the Panel's review of the capital projects in Appendix I and Appendix J of the Application together with BC Hydro's position on these capital projects, for the reasons outlined below, and **pursuant to section 45(5) of the UCA, if BC Hydro intends to pursue any of these extensions, the Panel directs BC Hydro to file CPCN applications for the following projects:**

- **a. Metro North Transmission**
- **b. West Kelowna Transmission/Westbank Substation Upgrade**
- **c. Northwest Substation Upgrade**
- **d. Peace Region to Kelly Lake 500kV Transmission Reinforcement**
- **e. Mainwaring Substation Upgrade**

a) <u>Metro North Transmission</u>

BC Hydro states that the purpose of this project is to "Reinforce the Metro North Transmission System by constructing a new 230 kV transmission circuit between Coquitlam and Vancouver to serve the load growth and strengthen the Metro Vancouver Regional Transmission System." Potential public interest issues include:

- Route selection, including crossing of Burrard Inlet;
- Impact of underground cables, overhead transmission lines;
- Electromagnetic fields and effect on health;
- Impact on property values; and
- Environmental impact.[141]

BC Hydro further explains that: "As a result of load growth, a shortfall of supply capacity is anticipated by winter 2018/2019 in the Metro North 230 kV Transmission System. An interim operational solution has been identified to temporarily resolve these constraints by reconfiguring the system with real-time switching operation, such that no load curtailment will be required until winter 2020, after which time this project is expected to resolve the constraints." [142]

[140] Ibid., BCUC IR 66.1.
[141] Ibid., BCUC IR 100.1.
[142] Exhibit B-1-1, Appendix J, p. 44.

The Commission finds the Metro North Transmission project is an extension as it is caused by load growth and public interest issues require a public review.

b) West Kelowna Transmission/Westbank Substation Upgrade

The West Kelowna Transmission Project will provide a second transmission line to supply Westbank Substation.[143] The Westbank Substation Upgrade project will increase the substation's summer firm capacity to address the current capacity deficit and future load growth. The project will also add a second 138 kV line position to connect a new transmission line to be built under a separate project.[144] The total value of the two projects is not yet determined, and at this time consultation with stakeholders has not been completed and both projects are in the identification phase.[145]

In response to a CEC IR, BC Hydro notes that it expects to file an application for a CPCN or section 44.2 for the West Kelowna Transmission project in F2018 or F2019.[146] However in its final argument, BC Hydro suggests the opposite:

> The planning allowance for each of the West Kelowna Transmission project and the Westbank Substation Upgrade project in Supplemental Appendix I-A indicate that these projects would not meet the threshold in BC Hydro's Capital Project Filing Guidelines for a CPCN or section 44.2 application. Both of the projects are in the Identification Phase, are not sufficiently advanced to have a preferred alternative and there is insufficient information on the scope of each project to establish a complete total project estimate. As the projects progress and Authorized Amounts are established for them, BC Hydro will confirm whether or not each of the projects meets the threshold.[147]

The Panel notes that this project has a planning allowance of $77.6 million and that the Westbank Substation Upgrade project is an additional $24 million. The Panel finds the West Kelowna Transmission project is an extension as it is adding a second transmission line. The Panel also finds that the Westbank Substation Upgrade project is an extension as it is the result of load growth. As the Westbank Substation Upgrade project is providing space for the West Kelowna Transmission project, the Panel finds these two projects are sufficiently linked that they could be expediently reviewed in one process.

c) Northwest substation Upgrade

BC Hydro submits that this project:

> …involves upgrades at Williston, Glenannan, Telkwa, Skeena and Minette substations. The northwest area of the province is connected to the main BC Hydro transmission system via a single radial 500 kV line. Currently the line and substations cannot be maintained without line outages during which the northwest area is separated from the main transmission system. At

[143] Ibid., Appendix J, p. 46.
[144] Ibid., Appendix J, p. 62.
[145] BC Hydro Final Argument, pp. 28–29.
[146] Exhibit B-10, CEC IR 72.3.2.
[147] BC Hydro Final Argument, Appendix A, p. 29.

> this time, such outages are not an issue because the northwest area load can be supplied by local generation. However, future load growth associated with LNG [liquefied natural gas (LNG)] and other industrial load interconnections will exceed the capacity of local generation meaning BC Hydro will be unable to meet normal reliability standards and customers' requirements.
>
> Additionally, the proposed interconnection of LNG Canada requires additional line positions at Minette substation and will cause voltage issues in the area."[148]

BC Hydro sets out important matters of public interest:

> The cost responsibility for the Northwest Substations Upgrades Project is dependent on whether a Liquefied Natural Gas or non-Liquefied Natural Gas industrial project is the driver for the required upgrades.
>
> If a non-Liquefied Natural Gas industrial project is the driver for the required upgrades, then BC Hydro's transmission extension policy (Tariff Supplement No. 6) will be applied to the project to determine cost responsibility between the customer and BC Hydro.
>
> If a Liquefied Natural Gas project is the driver for the project, then Order in Council No. 612 determines how system reinforcements costs associated with Liquefied Natural Gas projects are treated; specifically, Order in Council No. 612 requires that Liquefied Natural Gas customers being served at voltages of 60 kV or higher are responsible to "pay for full cost of interconnecting with the authority's transmission system and any system upgrades identified by the authority as required to service the customer.[149]
>
> …
>
> For Non-LNG customers, the risk of stranded assets is managed through the application of Tariff Supplement No. 6 cost allocation/security provisions, which requires the customer to pay the full cost of the interconnection facilities and provide security for the full cost of the System Reinforcements triggered by the addition of the customer's new load. Once the new load is in service, a portion of the security is released annually based on the security release formula in Tariff Supplement No. 6.
>
> For LNG customers the risk of stranded assets will be mitigated through the Order in Council 612, which requires LNG proponents to "pay the full cost of interconnecting to the authority's transmission system and any system upgrades identified.[150]

In response to BCOAPO, BC Hydro states further:

> …the difference in customer cost responsibility between Liquefied Natural Gas and Non-Liquefied Natural Gas customers is in how System Upgrades/System Reinforcement costs are treated. There is no difference in how Interconnection costs are treated.

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[148] Exhibit B-1-1, Appendix J, p. 53.
[149] Exhibit B-9, BCUC IR 105.1.
[150] Ibid., BCUC IR 105.1.1.

> Order in Council No. 612 requires that Liquefied Natural Gas customers being served at voltages of 60 kV or higher be responsible to "pay for full cost of ... any system upgrades identified by the authority as required to service the customer."
>
> The full cost is paid by the Liquefied Natural Gas customers at the time the upgrades are constructed and the payment is recorded in the capital project as Contribution in Aid of construction.
>
> For Non-Liquefied Natural Gas customers, Tariff Supplement No. 6 applies and cost allocation/security provisions require a customer to provide security for the full cost of the System Reinforcements triggered by the addition of the customer's new load. Once the new load is in service and revenues are collected by BC Hydro, a portion of the security is released annually based on the security release formula in Tariff Supplement No. 6.[151]

The Panel finds that ratepayers may be significantly affected by this project. The project is heavily influenced by whether BC Hydro is successful in attracting a suitable LNG customer. In order to make attempts to mitigate stranded asset risk, it appears to the Panel that Order in Council 612 suggests LNG customers pay for full cost of any required interconnection and upgrades. If a non-LNG project is the driver, Tariff Supplement No. 6 would apply and interconnection costs would be covered by the customer whereas upgrades would be covered by the transmission class**.**

d) <u>Peace Region to Kelly Lake 500kV Transmission Reinforcement</u>

BC Hydro states that the purpose of this project is to increase the Peace Region to Kelly Lake 500 kV transmission system transfer capacity to facilitate transmission of available generation from the Peace Region to the load centers in the Lower Mainland and Vancouver Island regions. It consists of two sections of three parallel 500 kV transmission lines: Peace to Williston section and Williston to Kelly Lake section. The first section is approximately 280 km and the second section is approximately 330 km.

Additional generation will be added in the Peace Region in the next 20 years including the Site C Clean Energy Project and IPPs. The additional generation will require increased transfer capability of the Peace Region to Williston section to supply the growing system load south of the Peace region and of the Williston to Kelly Lake section to supply the growing load in the Lower Mainland.[152]

BC Hydro also notes that: "The project is a System Plan Network Upgrade, for the benefits of all users of the transmission system… Based on the planning allowance and current Capital Filing Guidelines, BC Hydro will likely apply for a CPCN for the project."[153]

In response to Commission IRs: "BC Hydro confirms that there are likely to be significant public interest issues for the Peace Region to Kelly Lake 500 kV Transmission Reinforcement Project. Some of these potential issues

[151] Exhibit B-10, BCOAPO IR 2.85.1.
[152] Exhibit B-1-1, Appendix J, p. 54.
[153] BC Hydro Final Argument, pp. 40–41.

will involve compliance with the British Columbia Environmental Assessment Act (BCEAA), and First Nations consultation for land and site selections."[154]

The planning allowance cost estimate of $268 million exceeds BC Hydro's Capital Project Filing Guidelines threshold of $100 million; it is an extension and there may be significant public interest issues such as route selection and linkages to Site C**.**

e) <u>Mainwaring Substation Upgrade</u>

BC Hydro submits that the Mainwaring Substation project replaces assets that have reached end of life, and is not intended to provide additional capacity. BC Hydro explains that the project is currently in the Identification Phase and has not sufficiently advanced to have a preferred alternative and there is insufficient information on the scope. Therefore, BC Hydro cannot determine at this time whether the project is an extension, based on the meaning of extension in the Capital Project Filing Guidelines. As the project progresses to the Definition Phase and a preferred alternative is identified, BC Hydro will be able to determine if the project is an extension.[155]
BC Hydro also submits that "…based on the driver and need for the Project, we expect that most of the work will be Substation Distribution Assets. The power transformers and feeder sections are Substation Distribution Assets while the control building is a common asset to Transmission and Distribution. There is no expected work related to property assets."[156]

In BC Hydro's response to a CEC IR, the Company notes that it expects to file a CPCN or an expenditure approval application in fiscal 2018 or fiscal 2019 for this project.[157]

BC Hydro explains that an Area Plan for the area encompassing Mainwaring Substation is not currently available. When complete, the Area Plan will address load growth in the Vancouver (excluding downtown) and South Burnaby areas. In addition, BC Hydro notes that the redevelopment of the Mainwaring Substation will be considered in the Area Plan being prepared.[158]

The Panel finds the planning allowance of $92.9 million to be material. BC Hydro appears to be planning to file this project as a CPCN or a section 44.2 expenditure schedule in F2018 or F2019. The Panel finds this project will most likely include substation distribution assets and appears to likely be a major redevelopment, at least in part, as a result of load growth in the area. Given the potential community impact to a major urban center, the Panel finds the public interest issues require a full review.

[154] Exhibit B-9, BCUC IR 106.5.
[155] Ibid., BCUC IR 110.3.
[156] Ibid., BCUC IR 110.4.
[157] Exhibit B-10, CEC IR 1.72.3.2.
[158] Exhibit B-14, BCUC IR 267.1.

3.3.3 Other intervener issues

3.3.3.1 Project delivery

Intervener arguments

CEC "…submits that on an overall basis BC Hydro's track record has a considerable record of being over authorized amount projects."

CEC raises specific issues with respect to BC Hydro's capital expenditure plan:

1. BC Hydro should institute further measures to manage project costs;[159]and
2. The Commission should "engage BC Hydro …in building a better understanding of capital planning, decision making, and capital project implementation performance to enable ongoing assessment of its effectiveness;"[160]

BC Hydro Reply

BC Hydro responds to CEC in that it has a full and well documented planning process and that no further actions are required to manage project costs.[161] BC Hydro also notes that with respect to additional initiatives to apprise the Commission of its planning and execution, existing processes are sufficient.[162]

With respect to instituting further measures to manage project costs:

> BC Hydro submits that it already has a well-defined planning process that considers BC Hydro's system requirements, strategic priorities and rate impacts. BC Hydro has put groups and processes in place for project delivery. These processes have yielded results: projects delivered between fiscal 2012 to fiscal 2016 were 0.18 per cent under budget in aggregate.[163]

Commission determination

Capital spending directly affects finance charges and amortization, and indirectly affects operating costs. Capital spending is one of the largest components of BC Hydro's revenue requirement. Accordingly, effective project planning and delivery processes are essential to keeping rates reasonable and predicable.

The Panel finds that although overall BC Hydro projects delivered between fiscal 2012 to fiscal 2016 were comparable to budget in aggregate, there were several larger projects where BC Hydro was significantly over budget. The list of $5 million or greater projects that went over the expected amount over the last 5 years is provided below, with highlights indicating the larger projects that have gone significantly over budget:[164]

[159] CEC Final Argument, p. 136.
[160] Ibid.
[161] BC Hydro Reply Argument, pp. 79–80.
[162] Ibid., p. 80.
[163] Ibid., p. 80.
[164] Exhibit B-15, CEC IR 2.158.1

Fiscal Year	Project Title	Final / Forecast Costs	First Full Approved Expected Amount	Variance	First Full Approved Authorized Amount	Variance
2011/2012	Spillway Gates Reliability Program - Standby Power Supply	7,907,236	7,471,600	(435,636)	7,471,600	(435,636)
2011/2012	Dam Safety Seismic Hazard Model	9,123,541	5,913,300	(3,210,241)	7,413,300	(1,710,241)
2011/2012	Fort Nelson Resource Smart Upgrade	165,310,716	149,565,500	(15,745,216)	164,620,100	(690,616)
2011/2012	Terzaghi Spillway Gate Reliability Upgrade	38,914,564	21,871,200	(17,043,364)	26,134,700	(12,779,864)
2011/2012	Mica Sewage Treatment Plan	8,422,464	6,082,200	(2,340,264)	6,973,800	(1,448,664)
2011/2012	Cheakamus Spillway Gate Reliability Upgrade	63,594,343	36,432,600	(27,161,743)	49,293,000	(14,301,343)
2011/2012	Seton Spillway Gate Reliability Upgrade	22,283,627	16,837,500	(5,446,127)	20,310,400	(1,973,227)
2011/2012	Lake Buntzen Turbine System Replacement	15,348,684	14,239,600	(1,109,084)	18,162,600	2,813,916
2011/2012	G.M. Shrum Station Service Upgrade	30,780,836	29,804,600	(976,236)	34,508,200	3,727,364
2011/2012	Cheakamus U1 & U2 Turbine Upgrade	15,533,668	8,699,000	(6,834,668)	8,699,000	(6,834,668)
2011/2012	Bridge River 2 Penstock Recoating	9,300,502	7,980,000	(1,320,502)	8,980,000	(320,502)
2011/2012	2L22 Fraser River Crossing - Transmission Line Restoration	12,500,279	9,599,000	(2,901,279)	11,569,000	(931,279)
2011/2012	500 kV Airblast Circuit Breaker Replacement (Ingledow)	10,297,677	5,900,000	(4,397,677)	5,900,000	(4,397,677)
2011/2012	Clowhom Transmission Upgrade 1L44	7,140,901	5,570,600	(1,570,301)	5,570,600	(1,570,301)
2011/2012	Transmission Recurring Capital - Multiple circuits	9,498,619	8,427,000	(1,071,619)	8,427,000	(1,071,619)
2012/2013	G.M. Shrum Units 6 to 8 Capacity Increase	45,188,384	39,113,100	(6,075,284)	44,613,100	(575,284)
2012/2013	Transmission Recurring Capital - Multiple Circuits	8,984,892	8,925,000	(59,892)	8,925,000	(59,892)
2012/2013	Valemount 25kV Outdoor Metalclad Switchgear Replacement	6,001,305	5,572,000	(429,305)	5,572,000	(429,305)
2013/2014	Hugh Keenleyside Navlock Upstream and Downstream Control System Replacement	10,065,862	7,054,999	(3,010,863)	7,885,200	(2,180,662)
2013/2014	Ruskin Dam Safety Improvement Right Abutment Remediation (Stage 1)	16,317,752	14,535,000	(1,782,752)	20,878,000	4,560,248
2013/2014	Smithers Substation - Transformer Addition	6,487,028	5,636,000	(851,028)	5,636,000	(851,028)
2013/2014	5L44 Fraser River Crossing - Transmission Line Restoration	12,012,022	11,920,000	(92,022)	14,294,000	2,281,978
2013/2014	Cape Scott Wind Farm Project - CPC08 IPP	9,063,848	8,834,000	(229,848)	9,421,000	357,152
2013/2014	Vanderhoof Substation T1 Transformer Replacement	12,815,764	11,921,000	(894,764)	13,113,000	297,236
2013/2014	Kelly Lake Synchronous Condenser Unit 2 Refruhishment	6,861,160	6,531,000	(330,160)	7,184,000	322,840
2013/2014	Customer 1	23,963,210	21,686,000	(2,277,210)	28,346,000	4,382,790
2013/2014	Bridge River Generating Station 1 Transformer Addition	12,424,796	9,986,000	(2,438,796)	10,975,000	(1,449,796)
2014/2015	Mica SF6 Gas Insulated Switchgear Replacement	188,636,075	180,624,800	(8,011,275)	200,159,800	11,523,725
2014/2015	G.M. Shrum Fire Alarm Upgrade	11,350,823	11,101,600	(249,223)	12,101,600	750,777
2014/2015	Northwest Transmission Line	704,666,003	560,998,000	(143,668,003)	560,998,000	(143,668,003)
2014/2015	Kidd 1 - Substation Redevelopment	33,897,752	19,410,000	(14,487,752)	19,410,000	(14,487,752)
2014/2015	Forest Kerr Hydro projects (Forest Kerr, McLymont, Volcano)	7,041,003	6,250,000	(791,003)	6,863,000	(178,003)
2014/2015	Customer 2	13,614,832	10,483,000	(3,131,832)	10,483,000	(3,131,832)
2014/2015	Vancouver Island Terminal Synchronous Conderser unit 2 Refurbishment	10,212,124	5,861,000	(4,351,124)	6,751,000	(3,461,124)
2014/2015	Kidd 2 Substation (Richmond Area Reinforcement)	35,125,574	27,326,000	(7,799,574)	29,726,000	(5,399,574)
2014/2015	230 kV Airblast Circuit Replacements	7,611,972	6,718,000	(893,972)	7,108,000	(503,972)
2014/2015	System Spare Transformers Project	16,469,014	16,075,000	(394,014)	16,075,000	(394,014)
2015/2016	Interior to Lower Mainland Transmission Line	740,501,204	657,000,000	(83,501,204)	725,000,000	(15,501,204)
2015/2016	Hugh Keenleyside spillway gate reliability upgrade	112,863,877	90,226,000	(22,637,877)	101,983,500	(10,880,377)
2015/2016	G.M. Shrum Units 1 to 5 Rotor Rehabilitation	33,481,689	26,954,000	(6,527,689)	29,844,000	(3,637,689)
2015/2016	Horsey Substation-Add Feeder	13,769,258	9,951,000	(3,818,258)	11,771,000	(1,998,258)
2015/2016	Dawson Creek/Chetwynd Area Transmission	295,616,514	254,100,000	(41,516,514)	296,400,000	783,486
2015/2016	Merritt Area Transmission	59,823,967	55,834,000	(3,989,967)	64,534,000	4,710,033
2015/2016	Surrey Area Substation Project	79,799,383	76,405,000	(3,394,383)	94,405,000	14,605,617
2015/2016	Forestview 12/25 kV Voltage Conversion	10,531,268	7,974,000	(2,557,268)	8,816,000	(1,715,268)
2015/2016	Customer 3	5,863,882	5,049,000	(814,882)	5,552,000	(311,882)
2015/2016	Customer 4	33,352,862	30,666,000	(2,686,862)	35,933,000	2,580,138
2015/2016	Silverdale Substation	49,300,982	41,482,000	(7,818,982)	45,082,000	(4,218,982)
2015/2016	500 kV Airblast Circuit Breaker Replacement NIC/WSN/ACK	21,515,569	20,204,000	(1,311,569)	21,684,000	168,431
2015/2016	GMS Auxiliary Building Service Upgrade	9,610,135	7,560,200	(2,049,935)	7,560,200	(2,049,935)
2015/2016	60/138 kV Circuit Breakers Replacements	10,676,716	10,664,000	(12,716)	10,664,000	(12,716)
2015/2016	Ashton Creek 500 kV Circuit Breakers and Current Transformer Replacement	9,395,486	8,594,000	(801,486)	9,405,000	9,514
2015/2016	Good Hope Lake / Jade City	9,899,582	6,898,000	(3,001,582)	7,916,000	(1,983,582)

In addition to the larger projects that have gone significantly over budget as identified in the table above, the Panel in BC Hydro's Site C Inquiry found that Site C "is not within the proposed budget of $8.335 billion" and further that "the total cost at completion may be in excess of $10 billion as there are significant risks remaining that could lead to further budget overruns."[165]

The Panel acknowledges that the upcoming BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding will provide another opportunity for the Commission and interveners to further refine their understanding of the effectiveness of BC Hydro's capital processes. The Panel recommends the issue of the adequacy of BC Hydro's planning and execution related to large capital projects be explored in this upcoming proceeding.

[165] BCUC Site C Inquiry Final Report, p. 121, www.bcuc.com/Documents/wp-content/11/11-01-2017-BCUC-Site-C-Inquiry-Final-Report.pdf

3.3.3.2 Specific projects and plans

Intervener arguments

CEC

CEC raises three specific issues with respect to BC Hydro's capital expenditure plan:

1. BC Hydro should quantify the benefits of extending the refresh rates for laptops;[166]
2. The Commission should reduce BC Hydro's technology capital budget by the costs of the Graphic Design Tool project;[167] and
3. The Commission should further review the Enterprise Billing Infrastructure Project, including how it relates to the adoption of the SAP platform.[168]

CEABC

CEABC states it "sees only two projects mentioned in BC Hydro's Capital Plan that can address the need to serve the low-carbon electrification goals for the northeast gas producers and processors. These are:

- The Fort St. John and Taylor Electric Supply ($53 million, in the Implementation Phase); and
- Peace Region Electric Supply ("PRES", in the Identification Phase).

CEABC suggests that they are both transmission projects, urgently needed, and not a big portion of the approximately $20 billion Capital Plan. They should both be given the highest priority.[169]

CEABC further notes, "As for generation projects, the only real growth project in the Capital Plan is Site C, and it is an enormous long-lead-time project that is, unfortunately, set to produce its energy with no particular short term need in mind to be served. However, the other generation projects that could be producing energy that is actually needed (but at a much earlier time), are nowhere to be found in the Capital Plan. There are no generation projects in the Capital Plan, IPPs or otherwise that could serve the very current need for the electrification of northeast gas production and processing. These projects are needed long before the Site C energy will be available. They should be in the Capital Plan."[170]

CEABC requests a clean sheet analysis be completed for the Bridge and Campbell River projects, noting that further planning is required.[171]

BC Hydro reply

Regarding the reassessment of the refresh rate for laptop and desktop computers, BC Hydro notes that subject to its assessment criteria, periodic upgrades are required to ensure BC Hydro maintains stability, performance and the ability to connect to networks and peripherals.[172]

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[166] Ibid., p. 140.
[167] CEC Final Argument, p. 143.
[168] Ibid., p.143.
[169] CEABC Final Argument, p. 27.
[170] Ibid., p. 28.
[171] CEABC Final Argument, pp. 27–28.

With respect to eliminating the Graphic Design Tool project from proposed capital investments, BC Hydro notes that it has made adjustments for the project not proceeding.[173]

Finally, BC Hydro indicates that it does not believe that examining the Enterprise Billing Infrastructure Project as part of the SAP Inquiry should be pursued because the terms of the Inquiry have already been established.[174]

BC Hydro responds to CEABC by stating it "is advancing the Peace Region Electricity Supply Project through the project life cycle",[175] and notes that "the growing load under normal conditions is expected to be exceeded in the winter of fiscal 2025."[176]

With respect to the Bridge and Campbell River systems, BC Hydro provides specific references to the plans it has provided in response to Information Requests during the proceeding.[177]

Commission determination

The Panel denies CEC's requested changes to the refresh rates for laptops. The Panel finds BC Hydro's current plan a more effective way of ensuring BC Hydro is able to keep pace with rapidly occurring developments in laptop and tablet technologies, and that keeping pace ensure that cyber security requirements can be met and other technology risks are mitigated.

The Panel denies CEC's request to reduce BC Hydro's technology capital budget by the costs of the Graphic Design Tool project. It is the Panel's view that BC Hydro will be faced with the need to make ongoing adjustments to its technology projects and programs and that by reducing the technology capital budget by this amount would be a material change to the budget and it may unnecessarily restrict BC Hydro's ability to pursue other opportunities.

The Panel denies CEABC's request that BC Hydro change its plans for the Fort St. John to Taylor Electric Supply project, the Peace Region Electric Supply project, the Bridge River system projects, and the Campbell River system projects. The PRES project is driven by load in the Peace Region and though the integrated resource plan (IRP) indicated that the transmission capacity would be exceeded due to load in F2018, BC Hydro has now provided an update to F2025 instead.[178] Therefore, there would likely be no reason to now reprioritize and accelerate the project as recommended by CEABC.

The Panel also notes that the construction for Fort St. John to Taylor Electric Supply was started in July 2017 and is targeted to be complete in F2020, and further BC Hydro is using accepted utility practice to address system constraints until the PRES project is in service.[179] The Panel is satisfied with BC Hydro's "accepted utility practice" as explained in response to BCUC IR 102.2 and 102.3.[180]

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172 Ibid., para. 165, p. 81.
173 Ibid., para. 171, p. 82.
174 Ibid., para. 162, pp. 79, 80.
175 BC Hydro Reply Argument, p. 78.
176 Ibid., p. 78.
177 Exhibit B-14, BCUC IR 261.3, Exhibit B-15, CEABC IR 41.1.
178 BC Hydro Reply Argument, p. 78.
179 Ibid.

BC Hydro filed plans for Bridge River and Campbell River which the Company says addresses CEABC's concerns about the "clean sheet".[181] The Panel finds this to be adequate and therefore does not require further work on the Bridge River and Campbell River projects.

3.4 Deferral and other regulatory accounts

In its Application, BC Hydro provides detailed discussions of each deferral and regulatory accounts, including a description of the account, its history and the existing or proposed recovery mechanism or period of the account balance.[182]

BC Hydro's actual and forecast deferral and regulatory account balances for the F2015 to F2019 period in the original Application are as follows:

Table 3-12: Summary of Deferral and Regulatory Account Balances[183]

$-Million	F2015 Actual	F2016 Actual	F2017 Forecast	F2018 Forecast	F2019 Forecast
Opening Balance	4,699.5	5,434.4	5,908.3	5,684.7	5,894.2
Additions	799.1	796.6	269.8	258.2	174.4
Interest	67.2	72.5	76.1	68.4	60.2
Recoveries/Other	(131.4)	(395.2)	(569.5)	(117.1)	(122.7)
Net change	734.9	473.9	(223.6)	209.5	111.9
Closing Balance	5,434.4	5,908.3	5,684.7	5,894.2	6,006.1

Pertaining to the Amended Application requesting a freeze on rates for F2019, BC Hydro's amends this summary as follows:

Table 3-13: Summary of Deferral and Regulatory Account Balances[184]

$ Million	F2015 Actual	F2016 Actual	F2017 Forecast	F2018 Forecast	F2019 Forecast	F2019 Forecast (Rate Freeze)
Opening Balance	4,699.5	5,434.4	5,908.3	5,684.7	5,894.2	5,894.2
Additions	799.1	796.6	269.8	258.2	174.4	174.4
Interest	67.2	72.5	76.1	68.4	60.2	60.2
Recoveries / Other	(131.4)	(395.2)	(569.5)	(117.1)	(122.7)	26.7
Net Change	734.9	473.9	(223.6)	209.5	111.9	261.3
Closing Balance	5,434.4	5,908.3	5,684.7	5,894.2	6,006.1	6,155.5

[180] Exhibit B-9, BCUC IR 102.2, 102.3.
[181] BC Hydro Reply Argument, pp. 78–79.
[182] Exhibit B-1-1, Chapter 7, Section 7.5.
[183] Exhibit B-1-1, p. 7-4, Table 7-1.
[184] Exhibit B-25, BCSEA IR 4.6.1.

BC Hydro states that it is not requesting approval for any new regulatory accounts and many existing regulatory accounts are proposed to continue unchanged. Generally, BC Hydro is requesting approval to:

i. Continue or change the scope and names for some of its existing regulatory accounts;
ii. Establish amortization periods for those regulatory accounts that do not currently have approved recovery mechanisms; and
iii. Continue to apply interest in a number of regulatory accounts, and to initiate the application of interest on one regulatory account.[185]

There are currently 28 deferral or regulatory accounts that are approved for use. All but two accounts have been approved for ongoing use over the test period, including many that are required by section 7 of Direction No. 7.[186] BC Hydro states that it manages these accounts in accordance with "sound regulatory principles, the 2013 10 Year Rates Plan and Directions No. 6 and 7."[187] Specific details of BC Hydro's requested proposal are listed in Table 7-9 of the Application.[188]

For information purposes, BC Hydro describes its regulatory account policies and principles that guide its treatment and requests for new regulatory account and outlines its strategy to reduce the overall regulatory account balances by F2024.

In section 7.3 of the Application, BC Hydro sets out the five situations (and types of account) where it considers appropriate to use regulatory accounts and the amortization periods (recovery periods) for each type of account. In the same section, BC Hydro describes its criteria for assessing whether a risk is controllable or non-controllable (BC Hydro's Principles).

In section 7.4, BC Hydro discussed what it considers to be an appropriate materiality threshold for creating a new regulatory account – namely un-forecast and non-controllable expenditures with a net income impact greater than $10 million in a fiscal year.[189]

BC Hydro is not requesting approval for the positions put forward in sections 7.3 and 7.4 of the Application;[190] rather, BC Hydro states that it uses the principles in the design of its regulatory account requests including those put forward in the Application.

BC Hydro states that the "proposals regarding specific regulatory accounts should be evaluated by the …Commission individually on their merits, recognizing that exceptions to the principles can sometimes be warranted." [191]

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[185] BC Hydro Final Argument, p. 149.
[186] Ibid., p. 150.
[187] Exhibit B-1-1, p. 7-3.
[188] Ibid., pp. 7-51 to 7-60.
[189] Ibid., p. 7-16.
[190] Exhibit B-9, BCUC IR 125.1.
[191] Ibid., BCUC IR 125.1.

The following table summarizes the regulatory accounts for which BC Hydro is not requesting any changes to the scope, recovery mechanism or application of interest.

Table 3-14: No requested changes to scope, recovery mechanism or interest[192]

Cost of Energy Variance Accounts	
1	Non-Heritage Deferral Account
2	Trade Income Deferral Account
Other Cash Variance Accounts	
3	Real Property Sales
4	Mining Customer Payment Plan
Non Cash Variance Accounts	
5	Foreign Exchange Gains/Losses
6	Debt Management
Benefit Matching Accounts	
7	Demand-Side Management
8	Pre-1996 Contributions in Aid of Construction
9	Capital Project Investigation Costs
Non-Cash Provisions Accounts	
10	First Nations Provisions
11	Arrow Water Systems Provision
Rate Smoothing Account	
12	Rate Smoothing
IFRS Transition Accounts	
13	IFRS Pension
14	IFRS Property, Plant and Equipment

The following table summarizes BC Hydro's requested changes regarding its deferral and regulatory accounts with respect to account scope, recovery mechanism and the application of interest.

[192] Exhibit B-1-1, pp. 7-51 – 7-60; BC Hydro Final Argument, pp. 152–160.

Table 3-15: Summary of Regulatory Account Orders Requested by BC Hydro[193]

	Regulatory Account	Requested Changes to Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
Cost of Energy Variance Accounts				
1	Heritage Deferral Account	• Effective starting in F2017, exclude First Nations negotiation costs from the calculation of the heritage payment obligation for the purposes of deferring variances to the Heritage Deferral Account.	• No change	• No change
Other Cash Variance Accounts				
2	Storm Restoration Costs	• No change	• The closing F2016 account balance be recovered over the F2017 to F2019 test period; and • On an ongoing basis, the forecast account balance at the end of a test period be recovered over the subsequent test period.	• No change
3	Amortization of Capital Additions	• Continue the scope on an ongoing basis.	• The closing F2016 account balance be recovered over the F2017 to F2019 test period; and • On an ongoing basis, the forecast account balance at the end of a test period be recovered over the subsequent test period.	• No change
4	Total Finance Charges	• Continue the scope on an ongoing basis.	• The closing F2016 account balance in the account be recovered over the F2017 to F2019 test period; and • On an ongoing basis, the forecast account balance at the end of a test period be recovered over the subsequent test period.	• No change

[193] Ibid.

	Regulatory Account	Requested Changes to Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
5	Rock Bay Remediation	• Effective starting in F2017, and on an ongoing basis, actual Rock Bay remediation costs be deferred to this account each year, and forecast Rock Bay remediation costs be amortized from this account in each year.	• The closing F2016 account balance be recovered over the F2017 to F2019 test period; • Effective starting in F2017, and on an ongoing basis, the forecast interest charged to this account each year be amortized from this account each year; and • On an ongoing basis, the forecast account balance at the end of a test period be recovered over the next test period.	• Interest be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt (WACD).
6	Arrow Water Systems	• No change	• Continue to recover on an ongoing basis the annual costs charged to the regulatory account and to draw down the Arrow Water Provisions account by an equal amount.	• No change
7	Asbestos Remediation	• Rename to "Remediation Regulatory Account"; • Effective starting in F2017, and on an ongoing basis, actual asbestos remediation costs at BC Hydro facilities be deferred to this account each year; and • Effective starting in F2017, and on an ongoing basis, actual expenditures related to compliance with polychlorinated biphenyl (PCB) regulations be deferred to this account each year.	• The closing F2016 account balance be recovered over the F2017 to F2019 test period; • Effective starting in F2017, and on an ongoing basis, forecast asbestos remediation costs be amortized from this account each year; • Effective starting in F2017, and on an ongoing basis, forecast expenditures related to compliance with PCB regulations be amortized from this account each year; • Effective starting in F2017, and on an ongoing basis, the forecast interest charged to this account each year be amortized each year; and • On an ongoing basis, the forecast account balance at the end of a test period be recovered over the subsequent test period.	• Interest be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current WACD.

	Regulatory Account	Requested Changes to Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
8	Minimum Reconnection Charges	• This account be closed upon recovery of the balance in the account in F2017 rates.	• No change	• No change
Non Cash Variance Accounts				
9	Non-Current Pension Costs	• Rename to “Pension Costs Regulatory Account”; • On an ongoing basis, expand this account to defer the annual variance between the forecast costs and actual costs related to the operating cost portion of the post-employment benefits current service pension cost variances; and • Effective F2017, and on an ongoing basis, use the five-year average of actual past discount rates when forecasting pension costs.	• The portion of the forecast account balance at the start of a test period related to variances transferred to the account during the previous test period be amortized over a period of time based on the expected average remaining service life (EARSL) of the active plan members at the start of the test period; • The actuarial gain forecast to be transferred to this account in F2017, as a result of the proposed change in methodology to forecast pension costs, be amortized, beginning in F2018, over a 12-year period; • The portion of the actual or forecast account balance at the start of the test period related to variances between its actual and forecast non-current pension costs for the F2015 to F2016 period, be amortized over the 12-year period ending in F2028; and • The portion of the actual or forecast account balance related to variances between its actual and forecast non-current pension costs for the F2011 to F2014 test period, continue to be amortized over the 13-year period ending in F2027.	• No change
Benefit Matching Accounts				
10	First Nations Costs	• Effective starting in F2017, and on an ongoing basis, actual lump sum settlement payments be deferred to this	• The actual F2016 closing balance in this account that is related to the difference between the specific amortization	• Interest be applied to balances in this account, consistent with the application of interest to

	Regulatory Account	Requested Changes to Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
		account each year, and the forecast lump sum settlement payments be amortized over ten years, starting in the year of payment; • Effective starting in F2017, and on an ongoing basis, actual negotiation costs be deferred and recovered from this account each year; and • Effective starting F2017, and on an ongoing basis, actual annual settlement payments be deferred to this account each year and forecast annual settlement payments be amortized from this account each year.	amounts directed by Order No. G-48-14, and the calculation of amortization based on actual transfers into this account in F2014 to F2016, be amortized in F2017; • The actual F2016 closing balance in this account that is related to settlement payments and negotiations costs incurred prior to F2015 be amortized over eight years beginning in F2017; • The actual F2016 closing balance in this account that is related to the lump sum settlement payment made in F2016 be amortized over nine years, beginning in F2017; • Effective starting in F2017, and on an ongoing basis, the forecast interest charged to this account be amortized from this account each year; • On an ongoing basis, the forecast account balance in this account at the end of a test period related to the difference between amortization of forecast annual and lump sum settlement payments and the calculation of amortization based on actual annual and lump sum settlement payments during that test period be recovered over the subsequent test period; and • On an ongoing basis, the forecast account balance in this account at the end of a test period related to the difference between forecast interest recovered and actual interest charged to this account during that test period be recovered over the subsequent test period.	other variance accounts, based on BC Hydro's current WACD.

	Regulatory Account	Requested Changes to Scope	Requested Changes to Recovery Mechanism	Requested Changes to Interest
11	Site C	• On an ongoing basis, include in this account for deferral any Site C Clean Energy Project costs that cannot be capitalized under the Prescribed Standards.	• No change	• No change
12	Future Removal and Site Restoration	• Rename to “Dismantling Cost Regulatory Account”; and • Change the terms of the account to defer, on an annual basis, any variances between planned and actual dismantling costs, to be effective starting in F2017.	• On an ongoing basis, the forecast account balance at the end of a test period be recovered over the subsequent test period.	• Interest be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro’s current WACD.
13	SMI	• No change	• The actual F2016 closing account balance be recovered over a period of 13 years, starting in F2017, which is the remaining period of the estimated 15-year average life of Smart Metering and Infrastructure assets.	• No change
Non-Cash Provisions				
14	Environmental Provisions	• Starting in F2017 and on an ongoing basis, as actual PCB compliance costs are deferred to the Asbestos Remediation Regulatory Account, this account be reduced by an equal amount.	• No change	• No change

BC Hydro states its deferral and other regulatory account proposals are just and reasonable and submits the following:

1. Approved deferral and regulatory accounts do not need to be revisited.
2. BC Hydro is not requesting to change the scope of the majority (19) of its 28 deferral and regulatory accounts.
3. The accounts that BC Hydro is requesting to continue or modify the scope will continue to serve appropriate regulatory functions and promote fairness.
4. BC Hydro has proposed principled recovery mechanisms for its regulatory accounts, which will enable the recovery of account balances over a reasonable time.
5. BC Hydro's request to record interest on balances in some regulatory accounts recognizes that BC Hydro incurs carrying costs, and that this mirrors the approved treatment for other regulatory accounts that attract interest.

With the existing and proposed recovery mechanisms in place, BC Hydro forecasts that the total balance in the regulatory accounts at the end of the test period will be reduced by approximately 40 percent at the end of the 2013 10 Year Rates Plan period.[194]

Intervener arguments

McCandless is concerned that there is no Commission approved amortization period with BC Hydro's Rate Smoothing Account.[195] McCandless also raised objections regarding BC Hydro's regulatory account proposals related to pension costs.[196]

Zone II raised issues with BC Hydro's Regulatory Account Principles and considers that the proposed $10 million threshold is too low.[197]

Landale, AMPC, CEABC, were silent on BC Hydro's regulatory account requests.

CEC, BCOAPO, BCSEA, NIARG, MoveUp, and Zone II (other than its stated issue with the $10 million threshold) support BC Hydro's requested changes to the regulatory accounts as filed.

BCOAPO submits that BC Hydro's recovery period proposals cannot be accepted and applied blindly on an ongoing basis (particularly after the conclusion of the 2013 10 Year Rates Plan), as they may need to be adjusted in order to smooth future year over year rate adjustments. This need should be explicitly recognized by the Commission rather than approving the proposed recovery mechanisms on an ongoing basis.[198]

[194] BC Hydro Final Argument, pp. 149–150.
[195] McCandless Final Argument, pp. 5–6.
[196] Ibid., pp. 6–7.
[197] Zone II Final Argument, pp. 21–22.
[198] BCOAPO Final Argument, p. 33.

BCOAPO agrees with BC Hydro that that proposals regarding specific regulatory account should be evaluated individually on their merits. BCOAPO also submits that the Commission should not make a determination on either the principles or the materiality threshold.[199]

BC Hydro reply

BC Hydro states that "it has taken a rigorous approach to its deferral and regulatory accounts, and is on track to significantly reduce the balance in its accounts."[200]

BC Hydro responds to McCandless stating that a proposed recovery mechanism for the Rate Smoothing Regulatory Account in this Application is not necessary since the account balance will be recovered after the current test period, and that it will propose to recover the account balance in a subsequent revenue requirement application.[201] With respect to Mr. McCandless' objections to the proposals related to pension costs, BC Hydro states that it has provided sound rationale for its proposal.[202]

BC Hydro responds to Zone II stating that it "is not requesting approval of the principles set out in sections 7.3 and 7.4 of the Application, including the $10 million threshold."[203] Furthermore, BC Hydro states that "it can be difficult for it to absorb variances of even less than $10 million in a fiscal year. Given that there could potentially be multiple categories of costs to which BC Hydro could be exposed to variances, Zone II's position that BC Hydro should have to absorb variances up to $20 million for each is not reasonable."[204]

BC Hydro responds to BCOAPO stating that it has applied the principles by which recovery mechanisms should be established, as set out in the Application, "to its existing accounts and approvals sought, including ensuring recovery mechanisms have been applied for or are in place for all but two regulatory accounts in use or with balances at the beginning of the test period."[205]

Commission determination

The Panel takes no exception to the treatment of the regulatory accounts for which BC Hydro is not requesting any changes to the scope, recovery mechanism or application of interest. Subject to the determinations on issues addressed in sections 3.4.1 to 3.4.4, the Panel approves the remaining deferral and regulatory account requests contained in BC Hydro's Table 7-9 of the Application.

The Panel notes that with the exception of McCandless, none of the interveners oppose the acceptance of specific BC Hydro requested changes. The Panel acknowledges intervener concerns with respect to the magnitude of the balances in the deferral and other regularity accounts, the lack of recovery mechanism for recovery of the balance in the rate smoothing account, the ability to meet the 2013 10 Year Rates Plan and the requirement under section 7(k) of Direction No. 7 that the Commission must allow BC Hydro to set rates in such

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[199] Ibid., p. 37.
[200] BC Hydro Reply Argument, p. 84.
[201] Ibid., p. 89.
[202] Ibid., pp. 91–92.
[203] Ibid., p. 86.
[204] Ibid., pp. 86–87.
[205] Ibid., pp. 84–85.

a way as to allow the regulatory accounts to be cleared from time to time and within a reasonable period. The Panel considers these issues further in section 5.0.

In addition to the issue raised by McCandless related to the Non-Current Pension Costs Regulatory Account, in sections 3.3.1 to 3.3.3, the Panel considers the following additional issues that were explored during the proceeding:

1. First Nations Costs Regulatory Account;
2. Future Removal & Site Restoration Regulatory Account; and
3. Asbestos Remediation and Environmental Provisions Regulatory Account.

3.4.1 First Nations Costs Regulatory Account

BC Hydro explains that by Order G-53-02, the First Nations Costs Regulatory Account was established to defer negotiation and settlement costs with First Nations and to amortize the actual negotiation and approved settlement costs over ten years. Settlement costs include both lump sum payments and annual payments.

Further, by Order G-56-06, the First Nations Provisions Regulatory Account was approved, which established an asset that corresponds to the amount of a loss provision in the financial statements related to two First Nations claims. By Order G-11-08, the First Nations Costs Regulatory Account was expanded to include any First Nations claim and directed BC Hydro "…to file an application, when a settlement is completed, for accounting treatment of the final amount for the aggregate loss provision in respect to any settlement claim and the manner in which, if any, that amount may be recovered in rates."[206]

Starting in F2015, when settlement payments are made, and subsequently approved for recovery, the corresponding amounts are transferred to the First Nations Costs Regulatory Account from the First Nations Provisions Regulatory Account and recovered in rates through amortization of the Fist Nations Costs Regulatory Account. The amortization expense is included in BC Hydro's calculation of current operating costs.[207]

Starting in F2017, and on an ongoing basis, BC Hydro proposes to recover (i) forecast lump sum settlement payments over a ten-year period starting in the year of payment; (ii) forecast annual settlement payments in the year of payment; and (iii) actual negotiation costs in the year of expenditures. Differences arising from variances between forecast and actual lump sum settlement payments and forecast and actual annual settlement payments in a test period are proposed to be recovered over the following test period. [208]

As required by Direction No. 6, section 3(g), the Commission issued Order G-48-14 and directed the amortization of specific amounts from the account for fiscal 2015 and fiscal 2016 as well as the accrual of interest on the account going forward. Actual transfers to the account in fiscal 2015 and fiscal 2016 were different from the amounts on which the specific amortization in Order G-48-14 was based, resulting in BC Hydro recording higher

[206] Exhibit B-1-1, p. 7-33; Order G-11-08.
[207] Exhibit B-14, BCUC IR 287.7.
[208] Exhibit B-1-1, p. 7-33.

amortization than what would have resulted if amortization had been calculated on actual transfers. BC Hydro proposes to refund this difference in amortization to the ratepayers.[209]

Direction No. 7, section 11(d), directs the Commission to allow BC Hydro to recover in rates a specific list of "First Nations settlements". BC Hydro is requesting approval to recover costs related to these First Nations settlement costs and lump sum settlement costs related to two First Nations settlements not included in the list.[210] However, the Application did not specifically state that the amounts requested for recovery included First Nations settlement costs not in the list of "First Nations settlements" as set out in Direction No. 7 nor was there any discussion of these settlement costs in the Application. In response to a Commission IR, BC Hydro explained that these two lump sum settlements were not explicitly identified in its Application because they were already included in the F2015 and F2016 amortization as directed by Order G-48-14, and in this Application BC Hydro is requesting the recovery of the same lump sum settlements.[211]

BC Hydro confirmed that it is not requesting as part of this Application for blanket approval to recover all future settlement payments and specifically stated that "BC Hydro will request, in future revenue requirements applications, approval to recover future First Nations lump sum settlements not covered in Direction No. 7, and in accordance with British Columbia Utilities Commission Order No. G-11-08."[212]

Commission determination

In this section, the Panel discusses its issues pertaining to BC Hydro's proposal:

1. Amortization directed by Order G-48-14 pursuant to Direction No. 6, section 3(g);
2. The continuation of the First Nations Costs Regulatory Account and the linkage to legislative requirements; and
3. The recovery mechanism and interest.

Amortization Directed by Order G-48-14 Pursuant to Direction No. 6, section 3(g)

The Panel approves the actual fiscal 2016 closing balance in the First Nations Costs Regulatory Account that is related to the difference between the specific amortization amounts directed by Order G-48-14, and the calculation of amortization based on actual transfers into the First Nations Costs Regulatory Account in F2014, F2015 and F2016 be amortized in fiscal 2017. The Panel notes BC Hydro's explanation related to the two lump sum settlements that were forecast to occur in F2015 and F2016 and included in the F2015 and F2016 amortization. Since these expenditures did not actually occur in the F2015 and F2016 test period, the Panel agrees with BC Hydro's proposal to refund this difference in amortization to the ratepayers.

Continuation of the First Nations Costs Regulatory Account

The Panel approves the following:

i. **Effective starting in F2017 and on an ongoing basis, the actual lump sum settlement payments and annual settlement payments be deferred to the First Nations Costs Regulatory Account each year.**

[209] Ibid.

[210] Exhibit B-9, BCUC IR 141.4.1.

[211] BC Hydro Final Argument, pp. 165–166.

[212] Exhibit B-9, BCUC IR 141.10.

ii. **Effective starting in F2017 and on an ongoing basis, the forecast lump sum settlement payments be amortized over ten years, starting in the year of payment, and forecast annual settlement payments be amortized in the year paid from the First Nations Costs Regulatory Account.**

The Panel approves, effective starting in fiscal 2017, and on an ongoing basis, actual negotiations costs will be deferred to this account each year, and actual negotiations costs will be recovered from this account each year.

The Panel concurs with BC Hydro that the timing and uncertainty of settlement payments can lead to variances outside of management's control and can make accurate forecasting difficult especially for test periods greater than one year. Further, given the nature of the expense the variance in any one year could be significant. The Panel agrees with the proposals made by BC Hydro to defer to the First Nations Costs Regulatory Account the variances between actual and forecast lump sum and annual settlement payments. The Panel acknowledges BC Hydro's view that it should bear the risks associated with the variances between forecast and actual annual negotiations costs and does not take exception to actual negotiation costs being deferred and recovered from the First Nations Costs Regulatory Account each year.

Recovery mechanisms and interest

The Panel approves the following requests:

i. **Effective starting in F2017, and on an ongoing basis, the forecast interest charged will be amortized from First Nations Costs Regulatory Account each year.**

ii. **On an ongoing basis, the forecast account balance in the First Nations Costs Regulatory Account at the end of a test period related to the difference between the amortization of the forecast annual and lump sum settlement payments and the calculation of amortization based on the actual annual and lump sum settlement payments during that test period will be recovered over the subsequent test period.**

iii. **On an ongoing basis, the forecast account balance in the First Nations Costs Regulatory Account at the end of a test period related to the difference between the forecast interest recovered and the actual interest charged to the First Nations Costs Regulatory Account during that test period will be recovered over the subsequent test period.**

iv. **The actual F2016 closing balance in the First Nations Costs Regulatory Account that is related to the lump sum settlement payment made in F2016 will be amortized over nine years, beginning in F2017.**

v. **The actual F2016 closing balance in the First Nations Costs Regulatory Account that is related to settlement payments and negotiation costs incurred prior to F2015 will be amortized over eight years beginning in F2017.**

vi. **Interest be applied to the balances in the First Nations Costs Regulatory Account, consistent with the application of interest to other variance accounts, based on BC Hydro's current WACD.**

Direction No. 6, section 3(g) and Direction No. 7, section 7(i)(i), Order G-48-14 directed BC Hydro to amortize specific amounts from the First Nations Costs Regulatory Account for F2015 and F2016, and accrue interest at BC Hydro's WACD in a fiscal year. In the Panel's view, the requested amortization period of ten years for lump sum settlement payments and annually for annual settlement payments and interest is consistent with Order G-53-02 and the amortization period used to set amortization amounts in Direction No. 6 for F2015 and F2016.

Further, the Panel considers the amortization of the variance between the actual and forecast settlement payments and interest charged to the First Nations Costs Regulatory Account at the end of a test period over the next test period to be consistent with BC Hydro's principles for a variance account, as described in section 7.3 of the Application, with recovery mechanism for other variance accounts and will allow the account to clear from time to time.

Similarly, the requested recovery of the historical balance in the First Nations Costs Regulatory Account is consistent with the ten- year amortization period and will allow the account to clear from time to time.

3.4.2 Future Removal and Site Restoration Regulatory Account

BC Hydro describes that prior to F2005 it accrued a provision for future dismantling costs over the lives of certain assets. In F2005, the accounting rules changed and a provision for future dismantling costs was no longer required to be accrued. Order G-96-04 (BC Hydro's Fiscal 2005 - Fiscal 2006 Revenue Requirements Application) directed the fiscal 2004 balance of the Future Removal and Site Restoration provision be transferred to the regulatory account to be available to offset future removal and site restoration activities as originally intended rather than being transferred to retained earnings to the benefit of the Province, as would have been the case in the absence of the order. BC Hydro states that this account is being drawn down as actual expenditures are incurred and the account is expected to be fully drawn down during fiscal 2017. As a result, BC Hydro will begin to forecast annual dismantling costs for inclusion in rates. [213]

BC Hydro now proposes to use the regulatory account to capture the variance between forecast and actual dismantling costs and agrees that it will no longer be a benefit matching account but rather a cash variance account.[214] BC Hydro explains that variances in dismantling costs can occur for reasons outside of management's control such as the timing of when dismantling takes place, emergency dismantling and accounting changes, all of which can make forecasting difficult.[215]

BC Hydro submitted that the requested changes to the account result in significant changes and thus could be considered a request for a new regulatory account.[216] It further stated that because the changes are so pervasive that BC Hydro's regulatory account principles, including the $10 million threshold, could be applied.[217]

The table below shows the variances between actual and planned dismantling costs for F2012 through F2016:

[213] Exhibit B-1-1, pp. 7-36 to 7-38.
[214] Ibid.; Exhibit B-9, BCUC IR 139.2, BCUC IR 39.3.
[215] BC Hydro Final Argument, p. 160.
[216] Exhibit B-14, BCUC IR 283.1.1.
[217] Exhibit B-15, CEC IR 2.162.1.

Table 3-16: Actual and Planned Dismantling Cost Variances[218]

$ million	Appendix A Reference	F2012	F2013	F2014	F2015	F2016
Actual	Sch. 2.2, Line 32	20.2	16.4	32.2	22.4	24.2
Plan	Sch. 2.2, Line 32	34.3	20.9	21.0	24.6	31.2
Variance from Plan		(14.1)	(4.5)	11.2	(2.2)	(7.0)
% Variance from Plan		(41.0)	(21.5)	53.1	(9.1)	(22.4)
Variance from Prior Year		1.1	(3.8)	15.8	(9.8)	1.8
% Variance from Prior Year		5.9	(19.0)	96.5	(30.4)	8.0

BC Hydro submits that the variance in F2012 was due to timing as the activities took place in F2013, the variances in F2013 and F2016 were due to accounting matters where actual costs were not classified as dismantling costs, and the increase in the F2014 was due to an emergency repair.[219]

Intervener argument

In BCOAPO's view, oversight of the account is particularly important and variance explanations such as those provided in BCUC IR 134.6 relating to Amortization of Capital Additions could also be important in considering future balances in this account.[220]

Commission determination

For the F2017 to F2019 test period only, the Panel directs the establishment of a new regulatory account, the Dismantling Cost Regulatory Account (DCRA), to defer, on an annual basis, any variances between planned and actual dismantling costs during the F2017 – F2019 test period subsequent to the full draw down of the Future Removal and Site Restoration Regulatory Account.

The Panel acknowledges that there may be some factors that may cause variances between the forecast and actual dismantling costs to be outside of management's control. However, in the Panel's view, BC Hydro should be able to provide its best estimate on site dismantling and restoration necessary for the facilities that it operates and manages. Any variance remaining from factors outside of management's control may not be significant enough to warrant the variance treatment for the forecast dismantling cost.

For example, while reviewing BC Hydro's historical variances, the Panel notes that there have only been variances greater than BC Hydro's own materiality threshold for new accounts of $10 million in two of the past five years (F2012 and F2014). As BC Hydro points out, the largest variance in the past five years (F2012), relates to the timing of the activities which instead took place in F2013. The Panel considers the timing of dismantling activities to be largely within the control of the Company.

The Panel acknowledges that the ability to offset actual expenditures against the Future Removal and Site Restoration Regulatory Account since 2005 may have meant it was not necessary for BC Hydro to develop a robust forecast of dismantling costs in recent revenue requirement applications. It is for this reason that the

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[218] Exhibit B-9, BCUC IR 139.3.1.

[219] Ibid., BCUC IR 152.13.

[220] BCOAPO Final Argument, p. 34.

Panel accepts that BC Hydro may need to gain more experience with forecasting the timing of expenditures. However, the Panel does not agree, at this time, that BC Hydro should be allowed to recover the variance between planned and actual dismantling costs on an ongoing basis. The Panel is of the view that allowing BC Hydro to recognize forecast variances during this test period should allow BC Hydro sufficient time to gain more experience in forecasting dismantling costs in subsequent test periods.

The Panel approves BC Hydro's proposal to recover the forecast account balance at the end of the test period over the next test period, and the application of interest, consistent with the application of interest to other variance accounts, based on BC Hydro's current WACD.

BC Hydro's proposal to change the scope of the regulatory account to defer the variances between planned and actual dismantling costs and BC Hydro's proposal to rename the Future Removal and Site Restoration Regulatory Account to the DCRA are denied. Given that the balance of the existing account has been drawn down to zero in the first quarter of F2017,[221] the Panel further directs BC Hydro to close out this regulatory account in F2017.

With respect to BC Hydro's proposal to change the name of the Regulatory Account to the DCRA and change the terms of the account, the Panel considers BC Hydro's proposed change to be so pervasive that it constitutes a request for a new regulatory account. Although the Panel acknowledges that there may be some administrative advantages to changing the scope and purpose of an existing regulatory account rather than creating a new one, the Panel is not convinced that these advantages outweigh the benefits of transparency in the maintenance of regulatory accounts.

3.4.3 Asbestos Remediation and Environmental Provisions Regulatory Account

BC Hydro outlines that by Order G-88-10, the Commission approved the Environmental Provisions Regulatory Account in the amount of the loss provision liability recognized in the financial statements in respect of compliance with Polychlorinated Biphenyl (PCB) Regulations and remediation of environmental contamination at Rock Bay. Beginning in F2013, BC Hydro states it began to incur expenditures related to asbestos remediation at its facilities and, by Order G-7-13, the Asbestos Remediation Regulatory Account was established for unplanned asbestos remediation costs in F2013 and F2014, and the Environmental Provisions Regulatory Account was expanded to include the loss provision liability related to asbestos remediation at BC Hydro's facilities.[222]

As BC Hydro makes actual asbestos remediation expenditures, the balance in the Provisions Regulatory Account is reduced accordingly.[223] Unlike asbestos remediation costs, costs associated with compliance with PCB regulations are expensed as incurred and recovered through operating expense. In this Application, BC Hydro is requesting to continue to defer the costs associated with asbestos remediation in the Regulatory Account, and to also expand the Regulatory Account to defer the costs and capture the variances associated with compliance with PCB regulation.

[221] Exhibit B-9, BCUC IR 124.2.
[222] Exhibit B-1-1, p. 7-42.
[223] Ibid., pp. 7-42 to 7-43.

In accordance with Direction No. 7, section 7(f), the Commission must allow BC Hydro to continue to defer to the Asbestos Remediation Regulatory Account the variances between actual and forecast asbestos remediation costs. With respect to expenditures related to compliance with PCB regulations, there is no such direction from government.[224]

The annual variance between the actual and forecast costs from F2012 through F2016 for PCB has been less than $10 million. BC Hydro's own materiality threshold for new regulatory accounts, are shown in the table below:

Table 3-17: Materiality Threshold for New Regulatory Accounts[225]

$ million	Appendix A Reference	F2012	F2013	F2014	F2015	F2016
Actual	Sch. 2.2, Line 131	8.2	7.3	8.4	9.2	13.9
Plan	Sch. 2.2, Line 131	13.2	14.7	14.9	13.6	13.3
Variance from Plan		(5.0)	(7.4)	(6.5)	(4.5)	0.6
% Variance from Plan		(37.8)	(50.2)	(43.8)	(32.8)	4.8
Variance from Prior Year		1.4	(0.9)	1.1	0.8	4.8
% Variance from Prior Year		20.6	(10.7)	14.7	9.0	52.2

BC Hydro explains that there have been material variances (due to timing and scope) between forecast and actual amounts (in both dollar and percentage terms), and significant variances between years are possible in the future.[226] BC Hydro states that PCB costs are similar to asbestos costs in that they can differ from forecast due to the timing and scope of work undertaken.

Commission determination

In this section, the Panel considers issues pertaining to BC Hydro's proposal:

1. Treatment of asbestos remediation costs;
2. The proposed name change and treatment of PCB compliance costs; and
3. The recovery mechanism and interest.

Treatment of asbestos remediation costs

The Panel approves BC Hydro's proposal to continue to defer to the Asbestos Remediation Regulatory Account the variances between actual and forecast asbestos remediation costs pursuant to Direction No. 7. Effective starting in fiscal 2017, and on an ongoing basis, actual asbestos remediation costs at BC Hydro facilities will be deferred to this account each year, and forecast asbestos remediation costs will be amortized from this account each year.

The proposed name change and treatment of PCB compliance costs

BC Hydro's request to expand the regulatory account to capture PCB compliance costs is approved. Accordingly, BC Hydro's proposal to change the name of this account from Asbestos Remediation Regulatory

[224] Direction No. 7 to the BCUC, section 7.
[225] Exhibit B-9, BCUC IR 137.4.
[226] Ibid.; Exhibit B-14, BCUC IR 282.2, 282.2.1.

Account to the Remediation Regulatory Account is also approved. Effective starting in fiscal 2017, and on an ongoing basis, actual expenditures related to compliance with polychlorinated biphenyl regulations will be deferred to this account each year, and forecast expenditures related to compliance with polychlorinated biphenyl regulations will be amortized from this account each year. Although the treatment for PCB is not prescribed by Direction No. 7, as it is for asbestos costs, the Panel concurs with BC Hydro that PCB costs are similar in nature to asbestos costs in that they involve long-term estimates, the actual expenditures are susceptible to variances in amount and timing and differences from forecast due to the timing and scope of work undertaken. Furthermore, the Panel finds consistent treatment of asbestos and PCB costs is reasonable.

Recovery mechanism and application of interest

The Panel also approves the following requests related to BC Hydro's Remediation Regulatory Account:

i. **The closing F2016 balance in the Regulatory Account will be recovered over the F2017 to F2019 test period;**
ii. **Interest will continue to be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current WACD;**
iii. **Effective starting in F2017, and on an ongoing basis, the forecast interest charged to the Remediation Regulatory Account each year will be recovered in each year; and**
iv. **On an ongoing basis, the forecast Remediation Regulatory Account balance at the end of a test period will be recovered over the next test period.**

The Panel finds that the recovery period proposed for the Remediation Regulatory Account is consistent with BC Hydro's principles put forward in the Application, the treatment of other regulatory accounts, and will help ensure the account clears from time to time.

The Panel also finds that the proposed interest treatment is consistent with the application of interest to other variance accounts and is based on BC Hydro's current WACD.

3.4.4 Non-Current Pension Costs Regulatory Account

By Order G-16-09 dated March 13, 2009, the Commission approved the establishment of the Non-Current Pension Cost Regulatory Account to defer the difference between the forecast and actual non-current pension costs. This regulatory account was extended through various Commission orders during F2011 - F2014 and was further expanded to capture the difference between forecast and actual non-current other post employee benefits (OPEB). Section 7(g) of Direction No. 7 required the Commission to allow BC Hydro to defer, on an ongoing basis, to the Regulatory Account the variances between actual and forecast non-current pension costs. Section 3(n) of Direction No. 6 required the Commission to allow BC Hydro to amortize specific amounts in F2015-F2016.[227]

By Order G-148-15, the Commission approved the deferral of the operating cost variance between the Fiscal 2015 - Fiscal 2016 RRA forecast and actual fiscal 2016 post-employment benefits current pension costs, arising from a change in the actuarial discount rate to the Non-Current Pension Costs Regulatory Account for future

[227] Exhibit B-1-1, p. 7-29.

recovery, with the disposition of the variance to be addressed by BC Hydro in its next revenue requirement application.[228]

Post-employment benefit (PEB) costs are comprised of both the current and non-current service costs. Non-Current Pension Costs consist of plan income and interest expense.[229] Current Service Costs are the annual costs of accruing employees' post-employment benefits and the recognition of future employee benefits earned by the employee in the current year. These are included in the Standard Labour Rates charged to current work with 60 percent recovered through operating and maintenance (O&M) and 40 percent through capital.[230]

Beginning in F2017, and on an ongoing basis, BC Hydro proposes deferral treatment of current service cost variances and submits that this is appropriate because "these costs are difficult to forecast" and the "variances have been frequent and material, and determined by factors not within BC Hydro's control."[231] Furthermore, deferral treatment "will reduce volatility in operating costs, customer rates, and actual net income, and will ensure that ratepayers, over time, will pay only the actual costs incurred."[232]

BC Hydro stated that variances between forecast and actual Current Service Costs arise primarily due to changes to the actuarial discount rate and actuarial assumptions regarding factors such as inflation, mortality rate and workforce.[233] BC Hydro submitted that it only has control over variances related to changes in its workforce.[234]

Over the last five years the operating cost portion of variances in the Current Service Costs have ranged from $2.7 million over forecast to $22.14 million under forecast, as seen in the table below. Of the operating cost portion of the F2016 variance, $17.2 million or 78 percent was caused by a change in the actual actuarial discount rate, which was approved for deferral in the Regulatory Account by Order G-148-15.[235]

Table 3-18: Variance between Forecast and Actual Current Service Costs[236]

$ million					
	F2012	F2013	F2014	F2015	F2016
Actual	70.2	81.8	94.4	89.8	113.4
Plan (previous method)	74.7	77.2	79.8	76.5	76.5
Variance from plan	-4.5	4.6	14.6	13.3	36.9
Operating portion (@60%)	**-2.7**	**2.76**	**8.76**	**7.98**	**22.14**

[228] Ibid.
[229] Ibid., pp. 5-172, 5-173.
[230] Ibid., p. 5-171.
[231] BC Hydro Final Argument, p. 157.
[232] Ibid., p. 158.
[233] Exhibit B-14, BCUC IR 293.2, 293.2.1; The discount rate used to value Current Service Costs is calculated by a third party actuary and is based on a hypothetical basket of AA Canadian corporate debt that has the same cash flow as the BC Hydro pension plan in terms of both timing and amount (BCUC IR 294.9).
[234] Exhibit B-14, BCUC IR 293.2.1.
[235] Exhibit B-9, BCUC IR 63.6.
[236] Table prepared using information from Exhibit B-9, BCUC IR 63.8 & 140.6; Exhibit B-14, BCUC IR 289.1, Attachment 1.

In addition to its proposal for deferral treatment of current service cost variances, BC Hydro proposes an amortization period for the regulatory account balance based on the expected average remaining service life (EARSL) of the active plan members, and states the following:

> …prior to the test period the balance in the Non-Current Pension Costs Regulatory Account has been amortized over the Expected Average Remaining Service Life of the active employee group (EARSL) as determined by BC Hydro's actuary. In the Application, BC Hydro proposes to continue this amortization period, including for variances related to current service costs that we have proposed be transferred to the account.[237]

In BC Hydro's view, the EARSL is an appropriate amortization period for both the Non-Current Pension Costs and the Current Service Costs for the following reasons:[238]

- The pension costs relate to BC Hydro's active employee group, and the EARSL matches the expected service life of these employees;
- It minimizes intergenerational inequity: the EARSL matches the period of benefit to the ratepayers; and
- It smooths any related volatility in rates due to variances in Current Service Costs.

BC Hydro submitted that "variances related to current service costs include both cash and non-cash components."[239] In BC Hydro's view, the EARSL is an appropriate amortization period for the Current Service Cost variances because it provides the same matching benefits as with Non-Current Pension Costs.[240]

BC Hydro stated that if the Commission were to direct a shorter amortization period for the operating cost portion of the Current Service Cost variances, which would result in the amounts in the Regulatory Account to have different amortization periods, then it would be indifferent as to the separation of the Regulatory Account into two regulatory accounts.[241] BC Hydro also noted that an amortization period shorter than that proposed would result in larger amounts being amortized from the Pension Deferral Account each year, and submits that any differences in the amortization amount from that proposed would be transferred to the RSRA.[242]

In conjunction with the proposals to defer the operating portion of Current Service Pension Cost variances and amortize the regulatory account balance based on the EARSL of the active plan members, BC Hydro is proposing to change the method of forecasting pension costs to use a five year historical average of actual discount rates (Proposed Method) as opposed to the current discount rate in effect at the time the forecast was prepared (Previous Method).[243] For the current test period, the discount rate to forecast Current Service Costs under the Proposed Method is 4.38 percent while under the Previous Method is 3.81 percent.[244]

[237] Exhibit B-14, BCUC IR 296.2.
[238] BC Hydro Final Argument, p. 163; Exhibit B-14, BCUC IR 296.3.
[239] Exhibit B-14, BCUC IR 296.3.
[240] Exhibit B-9, BCUC IR 140.8.
[241] Exhibit B-14, BCUC IR 296.4.
[242] Ibid., BCUC IR 296.3.2.
[243] Exhibit B-1-1, p. 7-55.
[244] Exhibit B-14, BCUC IR 294.3, p. 5; BCUC IR 289.2; the five-year average discount rate for Current Service Costs related to Other PEB is 4.5%. This rate is different from the 4.38% used to calculate the Current Service Costs for the pension plan because there are differences in the amount and timing of cash flows and demographics between the two plans.

BC Hydro submitted that pension costs are highly sensitive to changes in the discount rate, and that a one percent change in the discount rate results in approximately a $30 million impact to Current Service Costs and approximately $550 million impact to Non-Current Service Costs as an actuarial gain or loss.[245] BC Hydro further submitted that "over the period from F2011 to F2016 the annual discount rate has ranged from a high of 6.12 per cent to a low of 3.51 per cent, giving rise to large variations between actual and planned results, and making it difficult to accurately forecast pension expense."[246]

BC Hydro stated that the Previous Method did not consider variability in future discount rates, and could cause more volatility compared to the Proposed Methodology year-over-year over the long-term when discount rates increase and decrease between years.[247] In BC Hydro's view, this change in methodology "may help to minimize intergenerational inequity caused by volatility in actual costs compared to plan."[248] BC Hydro further submitted that a five-year average approach matches the approach used for forecasting other items that are volatile, uncontrollable and for which there is no other reasonable basis to forecast.[249] However, BC Hydro submitted it is not aware of any other circumstances where a five-year average is used to forecast a future discount rate.[250]

In addition to the Proposed Method, BC Hydro also explored using a market forecast of interest rates as a proxy for market expectations of future discount rates (Market Based Method) since it is not aware of a source for forecast market discount rates.[251]

As illustrated in the table below, the cumulative variance over the last five years is more than twice as large using the Proposed and Market Based Methods as opposed to the Previous Method. This is attributable to the discount rates consistently decreasing over the past five years.

[245] Exhibit B-14, BCUC IR 294.3, p. 3.
[246] Exhibit B-1-1, p. 7-30.
[247] Exhibit B-14, BCUC IR 294.3, p. 4.
[248] Exhibit B-1-1, p. 7-30.
[249] Exhibit B-14, BCUC IR 294.3
[250] Ibid., BCUC IR 294.10.2.
[251] Ibid., BCUC IR 294.3.

Table 3-19: Current Service Costs – Comparison of Previous, Proposed and Market Based Methodologies[252]

$ million	F2012	F2013	F2014	F2015	F2016	Total (F12-F16)	Total (F12-F16) operating portion @ 60%
Actual service cost	70.2	81.8	94.4	89.8	113.4		
Forecast:							
Previous method	74.7	77.2	79.8	76.5	76.5		
Proposed method	63.3	65.5	67.7	60.7	60.1		
Market Based method	74.7	71.5	60.5	57.9	40.8		
Variance between actual and forecast:							
Previous method	**-4.5**	**4.6**	**14.6**	**13.3**	**36.9**	**64.9**	**38.94**
Proposed method	**6.9**	**16.3**	**26.7**	**29.1**	**53.3**	**132.3**	**79.38**
Market Based method	**-4.5**	**10.3**	**33.9**	**31.9**	**72.6**	**144.2**	**86.52**
Discount Rate	F2012	F2013	F2014	F2015	F2016		
Actual	5.42%	4.62%	4.00%	4.37%	3.51%		
Previous Method	5.31%	5.31%	5.31%	4.62%	4.62%		
Proposed Method	6.00%	6.00%	6.00%	5.51%	5.51%		
Market Based Method	5.31%	5.50%	6.15%	5.26%	6.21%		

BC Hydro also stated that under the Previous Method, there is no variance between the forecast and actual Current Service Costs in F2017.[253] However, under the Proposed Method, there is a $10.1 million variance in the actual operating cost portion of the Current Service Costs compared to the forecast costs.[254]

BC Hydro stated that the Proposed Method, if approved by the Commission, "will be used as the basis for forecasting current and non-current pension costs for regulatory accounting purposes," which would result in a $335.7 million Non-Current Pension Costs actuarial gain and a net reduction to the Regulatory Account balance of $325.6 million in F2017.[255]

Intervener argument

With respect to the recovery method, McCandless states that "recovering the balance in the Non-Current Pension Regulatory Account over the expected average service life of the employees is consistent with the pension regulatory accounts for other regulated Canadian power utilities."[256]

However, in McCandless' view, using the Proposed Method would result in an understatement of "the required rate increase," assuming that interest rates continue to decrease. McCandless further submits that forecasting pension costs using a five-year average discount rate is not consistent with other regulated utilities.[257]

[252] Table prepared using information from Exhibit B-14, BCUC IR 294.3 & 2.294.7, Attachment 1; Exhibit B-9, BCUC IR 140.6.
[253] Exhibit B-14, BCUC IR 297.11.1, BCUC IR 295.2.
[254] Exhibit B-9, BCUC IR 140.17; Exhibit B-14, BCUC IR 297.12.
[255] Exhibit B-14, BCUC IR 294.3.1, BCUC IR.294.13: $335.7 million reduction from actuarial gain (Non-Current Pension Costs) less $10.1 million addition (Current Service Costs) in the Regulatory Account balance.
[256] McCandless Final Argument, p. 7.
[257] Ibid.

BC Hydro reply

BC Hydro responds to McCandless stating that the impact of the Proposed Method "on the forecast revenue requirements depends on one's assumption about future discount rates, which are inherently difficult to predict."[258] Furthermore, "BC Hydro's proposed approach is consistent with how BC Hydro sets baselines for other items that are volatile, uncontrollable and for which there is no other reasonable basis to forecast."[259]

Commission determination

In this section, the Panel considers issues related to BC Hydro's proposals including:

1. The proposed expansion of the Non-Current Pension Costs Regulatory Account to capture variances in current service costs and the proposed recovery mechanism of the variances related to the operating cost portion of current service costs; and
2. The proposed change in the forecasting methodology.

Expansion of the regulatory account and recovery mechanism

The Panel approves the following BC Hydro requests regarding the recovery mechanism for the Non-Current Pension Costs Regulatory Account:

1. **The portion of the forecast account balance at the start of a test period related to the variance transferred to the account during the previous test period will be amortized over a period of time based on the EARSL of the active plan members at the start of the test period.**
2. **The portion of the actual or forecast account balance at the start of the test period related to variances between its actual and forecast non-current pension costs for the F2015 to F2016 test period will be amortized over the EARSL of the active plan members at the beginning of the F2017 to F2019 test period.**
3. **The portion of the actual or forecast account balance at the start of the test period related to variances between its actual and forecast non-current pension costs for the F2011 to F2014 test period continue to be amortized over the EARSL of the active plan members at the beginning of the fiscal 2015 to F2016 test period.**

The Panel concurs with BC Hydro that the EARSL of the active plan members continues to be an appropriate recovery period for Non-Current Pension Costs. Further, the proposed recovery period is consistent with BC Hydro's regulatory account principles outlined in the Application, is consistent with the pension regulatory accounts for other regulated Canadian power utilities, and will help ensure the account clears from time to time.

The Panel denies BC Hydro's proposal to include in the Non-Current Pension Costs Regulatory Account the deferral of the annual variance between the forecast costs and actual costs related to the operating cost portion of post-employment benefit current pension costs. The request to change the name of the Non-Current Pension Costs Regulatory Account, effective fiscal 2017, and on an ongoing basis, to the Pension Costs Regulatory is denied. The Panel directs the following:

i. **The establishment of a new regulatory account, PEB Current Pension Costs Regulatory Account, to defer the annual variance between the forecast costs and actual costs related to the operating cost portion of PEB Current Pension Costs, on an ongoing basis;**

[258] BC Hydro Reply Argument, p. 92.
[259] Ibid.

ii. **The transfer of the F2016 variance of $17.2 million approved by Order G-148-15 from the Non-Current Pension Costs Regulatory Account to the PEB Current Pension Costs Regulatory Account, with this amount to be amortized over the F2017 – F2019 test period; and**

iii. **The portion of the forecast account balance in the PEB Current Pension Costs Regulatory Account at the start of a test period related to the variance transferred to the account during the previous test period is to be amortized over the subsequent test period.**

The Panel acknowledges that there are uncontrollable factors that can cause large variances between forecast and actual PEB current service costs and as a result, considers it appropriate to allow for the deferral of test-period variances. However, the Panel notes that current and non-current service costs have significant differences in characteristics. The Panel notes current service costs are an estimate of the annual operating costs of accruing employees' post-employment benefits and represent the recognition of future employee benefits earned by the employee in the current year. Therefore, the Panel is not convinced that the benefits to ratepayers from incurring annual costs is equivalent to the matching benefits from smoothing the components of pension costs included in Non-Current Pension Costs (e.g. actuarial gains and losses).

Further, BC Hydro has not provided any evidence indicating amortization of current service costs over the EARSL of the active plan members is consistent with any other regulated Canadian power utilities and notes McCandless' submission that this is not the case. Therefore, it is the Panel's view that the EARSL of the active plan members is not an appropriate amortization period for the operating cost portion of current service cost variances, and instead find that a shorter amortization period would be more appropriate to minimize intergenerational inequity. Consistent with the treatment of other operating cost variance accounts where there are uncontrollable factors, the Panel finds a reasonable period to be the next test period.

The Panel notes that since the Non-Current Pension Costs Regulatory Account will not be expanded as proposed by BC Hydro, its proposal to rename the Non-Current Pension Costs Regulatory Account to the Pension Costs Regulatory Account is not necessary.

Change in forecasting methodology

The Panel denies BC Hydro's proposal to use an average of actual past discount rates used in the calculation of actual current service costs in the preceding five fiscal years for forecasting purposes, and directs BC Hydro to continue with its previous method of using the discount rate in effect at the time the forecast was prepared. The Panel finds that the evidence comparing the alternatives does not support that using an average of the preceding five years of the actual discount rates will more effectively mitigate the volatility in pension expense. The Panel also notes that under the Proposed Method, there is a $10.1 million variance for F2017 in the actual operating cost portion of the current service costs compared to the forecast costs that would not be recognized if the Previous Method was retained. Further, the variance protection provided with the establishment of the PEB Current Pension Costs Regulatory Account will assist in reducing the volatility of any variances experienced in F2018 and F2019.

The Panel acknowledges that the discount rates are difficult to predict with certainty, however it sees no link between the historical five-year average discount rate and the expected discount rate in the test period. BC Hydro acknowledges it is not aware of any other circumstances where a five-year average is used to forecast a future discount rate.

With respect to BC Hydro's submission that averaging may be a reasonable approach for other expenses that are volatile, uncontrollable and for which there is no other reasonable baseline, the Panel is not convinced this logic applies to estimates that are sensitive to future interest rate and market conditions.

The Panel's selection of the Previous Methodology considers BC Hydro's preference to replace the Proposed Methodology with the Previous Methodology in the event that the Panel does not approve its proposal.[260]

Since the F2017 forecasted actuarial gain included in the Application would not be recognized using the previous forecast method, the Panel denies BC Hydro's proposal to amortize this gain over the EARSL of the active plan members at the beginning of fiscal 2018.

The Panel notes that the combined effect of the Panel determinations with respect to BC Hydro's requested changes to the Non-Current Pension Costs Regulatory Account would increase the balance in the RSRA.

3.5 Demand side management

3.5.1 Approvals sought

BC Hydro is requesting acceptance of the following demand side management expenditure schedule for F2017 – F2019.[261]

Table 3-20: F2017 to F2019 DSM Expenditure Schedule

	DSM Expenditures ($ million)
F2017	113.7
F2018	104.8
F2019	100.7
Thermo-Mechanical Pulp (F2017–F2019)	42.7
Three-Year Total	361.1

3.5.2 Legislative framework

Subsection 44.2(3) of the UCA gives the Commission the discretion to either accept or reject the expenditure schedule.

Pursuant to subsection 44.2(5.1) of the UCA, in determining whether to accept an expenditure schedule, the factors that the Commission "must consider" (in addition to considering the interests of persons in British Columbia), include: British Columbia's energy objectives; an applicable integrated resource plan approved under section 4 of the CEA; the extent to which the schedule is consistent with the requirements under section 19 of

[260] Exhibit B-14, BCUC IR 294.3.3.
[261] BC Hydro Final Argument, p. 263; Exhibit B1-1, Table 10-1; Exhibit B-14, BCUC IR 314.3

the CEA; and the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation.

The financial treatment of BC Hydro's DSM expenditures is also subject to directions from government: recovery in rates of the expenditures on the Thermo-Mechanical Pulp (TMP) Program is required by the Direction to the Commission respecting BC Hydro's TMP Program; and pursuant to Direction No. 7 BC Hydro's development, implementation and administration costs for DSM are recorded in the DSM Regulatory Account and amortized over 15 years.[262]

The Demand-Side Measures Regulation, BC Reg. 326/2008 (DSM Regulation), defines the DSM cost-effectiveness tests to be used by the Commission in evaluating a DSM application under subsection 44.2(5.1)(d) of the UCA.

Position of the parties

BC Hydro submits that section 44.2 of the UCA does not provide the Commission with the authority to direct BC Hydro to file a DSM expenditure schedule, make additions to a DSM expenditure schedule, or change the design of a particular DSM program.[263] BC Hydro further states: "In not accepting a portion of the expenditure schedule, the Commission would be able to state in its reasons for decision why it did not accept that certain expenditures contained in the demand-side management plan were in the public interest. Depending on the reasons, this rejection could result in BC Hydro making an addition to its expenditure schedule or changing the design of a particular demand-side management program."[264]

BCSEA submits the Commission has ample authority to reject a DSM expenditure schedule for stated reasons that may prompt the utility to propose a modified expenditure schedule.[265]

The CEC submits that section 44.2 is not exhaustive with regard to jurisdiction over demand-side measures and that the Commission can order enhancement of BC Hydro's performance under subsection 60 (1) (b) (iii) through additional DSM if the Commission considers those to be valuable in increasing efficiency, reducing costs and enhancing BC Hydro's performance.[266] BC Hydro disagrees, stating the words of this section do not indicate that the Commission can issue an order directing BC Hydro to pursue demand-side measures.[267]

Panel discussion

The Panel agrees with BC Hydro that section 44.2 of the UCA does not provide the Commission with the authority to direct BC Hydro to file a DSM expenditure schedule, make additions to a DSM expenditure schedule, or change the design of a particular DSM program. However, the Panel notes that, under subsection 44.2(2), BC Hydro would not be able to recover DSM costs in final rates unless these costs have been accepted by the Commission under section 44.2.

[262] BC Hydro Final Argument, pp. 14, 15.
[263] Ibid., p. 14.
[264] Exhibit B-9, BCUC IR 167.3.
[265] BCSEA Final Argument, p. 6.
[266] CEC Final Argument, p. 13.
[267] BC Hydro Reply Argument, pp. 112–113.

The Panel also agrees with BC Hydro that the wording of subsection 60(1)(b)(iii) does not support the Commission using this section of the UCA to direct BC Hydro to pursue additional DSM measures.

3.5.3 Overview

BC Hydro submits that its request for acceptance of DSM expenditures is in the public interest and reflects a modernized and more cost-effective DSM Plan that continues broad DSM and is responsive to changing system needs and the 2013 10 Year Rates Plan. BC Hydro submits that it retains the ability to ramp up DSM in the future, as needed.[268]

BC Hydro submits that it would have a limited ability to increase expenditures over the test period, stating that there would be a period of only 18 to 21 months over which to increase spending and it would be a challenge for programs or initiatives to ramp up expenditure and activity levels over such a short timeframe. BC Hydro further states that if the expenditure schedule was rejected on the basis of insufficient funding it is possible that it could result in a decrease in DSM spending over the test period to minimize cost recovery risk.[269]

BCSEA asks the Commission to reject BC Hydro's DSM Plan under section 44.2 and to indicate in its reasons for decision that the 2013 IRP (i.e., the alternative F2017-F2019 DSM expenditures based on the 2013 IRP) would be in the public interest. BCSEA submits: "The DSM Plan is inconsistent with the Government-approved 2013 IRP. It would entail economically inefficient waste of energy. With the 2013 IRP, total customer bill savings would be $842 million more over F2016-F2024 than with the DSM Plan on a portfolio basis."[270]

BCOAPO submits that BC Hydro should maintain its current spending envelope, and work together with ratepayers and stakeholders to mitigate potential rate impacts, and to determine which programs need to be eliminated, modified, or expanded. [271]

CEC submits that BC Hydro should not reduce its spending relative to the 2013 IRP. The CEC recommends that the Commission provide BC Hydro with a recommendation to develop a DSM plan maximizing cost-effective DSM spending in its future revenue requirements applications.

CEC further submits that BC Hydro should be maximizing the production of all DSM energy below the market price of energy, in order that the energy can be sold at a profit. The CEC believes that it is inadequate for BC Hydro to reference only the impact on the BC Hydro rates plan and submits that BC Hydro should be concerned about the impact on ratepayers' bills of the cost of energy. [272]

CEABC supports an increased focus on growing the load (electrification) and a reduced focus on DSM. CEABC states:

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[268] BC Hydro Final Argument, p. 2.
[269] Exhibit B-9, BCUC IR 167.4.
[270] BCSEA Final Argument, pp. 1–2.
[271] BCOAPO Final Argument, p. 4.
[272] CEC Final Argument, pp. 195–196.

> Accordingly, given BC Hydro's current state of depressed demand, [CEABC] recommends against spending hundreds of millions of dollars on new programs intended to depress the demand even further. These expenditures are both unnecessary, and unhelpful. Unnecessary, because the increasing prices have already accomplished the job of reducing demand, and unhelpful, because the additional expenditures will only further exacerbate the rate increases.[273]

NIARG supports BC Hydro's requested DSM expenditure schedule as being in the public interest, although more could and should be done, particularly in the non-integrated areas.[274] Zone II is encouraged by BC Hydro's DSM expenditure schedule for the test period and submits that the Commission should accept it as filed, subject to recommendations that Zone II seeks to ensure its communities benefit from DSM expenditures.[275]

Commission determination

To determine whether to reject, accept, or accept in part BC Hydro's DSM expenditure request, the Panel considers BC Hydro's proposed DSM portfolio against each of the requirements of subsection 44.2(5) of the UCA and also reviews of the individual DSM programs proposed.

The Commission Panel accepts BC Hydro's DSM expenditure schedule contained in the Application. The Panel explains its reasoning in the following section. In subsection 3.5.4, the Panel addresses BCSEA's concerns with the size of the DSM funding envelope and in subsections 3.5.5 to 3.5.8, the Panel outlines a number of findings and recommendations related to BC Hydro's DSM programs.

3.5.4 Size of the DSM funding envelope

In considering whether BC Hydro's DSM expenditure schedule is in the public interest, the Commission is required to consider the applicable IRP approved under section 4 of the CEA and BC's energy objective of BC Hydro reducing its expected increase in demand for electricity by the year 2020 by at least 66 percent.

A comparison of BC Hydro's proposed DSM spend with the levels proposed in the 2013 BC Hydro IRP is provided in the table below.

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[273] CEABC Final Argument, pp. 11–12.
[274] NIARG Final Argument, pp. 1, 3.
[275] Zone II Final Argument, pp. 7–9.

Table 3-21: Comparison of BC Hydro's proposed DSM spending with the 2013 IRP[276]

	BC Hydro 2013 IRP F2017-F2019 ($ m) [277]	DSM expenditure schedule F2017-F2019 ($ m)[278]	Variance ($ m)[279]	Variance %
Codes and Standards	18.5	14.5	(4)	(22%)
Rate Structures	6.6	3.5	(3.1)	(47%)
Programs: • Residential (incl. low income)	55.6	37.9	(17.7)	(32%)
• Commercial	132.5	99.4	(33.1)	(25%)
• Industrial (incl. TMP)	139.3	125.6[280]	(13.7)	(10%)
• Total	327.3	262.9	(64.4)	(20%)
Supporting Initiatives	61.2	42.4	(18.8)	(31%)
Capacity focused DSM	0	38.6	38.6	n/a
Total	**413.6**	**361.9**	**(51.7)**	**(13%)**

By letter dated December 16, 2015, the Minister of Energy and Mines confirmed that government supports BC Hydro's DSM plans and expenditure levels for the F2017 to F2019 period as a prudent and responsible evolution of the DSM plan approved by government as part of the 2013 IRP.[281] The Minister also confirmed that government understands that as a result of these changes, BC Hydro will achieve a lower level of electricity savings than was established in the 2013 IRP.[282]

BC Hydro's energy load resource balance after planned resources shows that BC Hydro expects to be in a surplus energy position until F2031.[283]

BC Hydro states that the continuation of the DSM moderation strategy as recommended in the 2013 IRP avoids a cumulative rate impact of approximately 2.7 percent by the end of the F2020 to F2024 period compared to the outlook forecast in the 2013 IRP.[284] BC Hydro estimates that about 50 percent of the rate increase would be due

[276] Exhibit B-14, BCUC IR 311.3.
[277] Exhibit B-9, BCUC IR 168.3.
[278] Exhibit B-1-1, p. 10-33.
[279] Exhibit B-14, BCUC IR 311.3.
[280] Includes $42.7 of TMP funding (Exhibit B-14, BCUC IR 314.3).
[281] Exhibit B-1-1, pp. 10-25, 10-26.
[282] Ibid.
[283] Ibid., p. 3-31.
[284] BC Hydro Final Argument, p. 16.

to reduced sales to customers while the remaining 50 percent would be a result of an increase in DSM expenditures.[285]

Position of the parties

Minister of Energy and Mines' letter of support

BC Hydro submits that the Minister's letter expresses support for the DSM plan as a prudent and responsible evolution of the DSM plan approved by government as part of the 2013 IRP, and that the Minister's letter should be given significant weight as a demonstration of government support for the DSM plan.[286] However, BCOAPO submits that the letter should not be given significant weight as it does not help in answering the relevant question of whether the reduced spend is in the public interest.[287]

2013 10 Year Rates Plan

BC Hydro states that it did not select a DSM plan with higher expenditure levels because, in part, it would increase rates relative to the proposed DSM Plan, and that this upward pressure on rates would challenge BC Hydro's ability to meet the targets under the 2013 10 Year Rates Plan.[288]

CEC submits that the Commission is not bound to accept the target rate increase of 2.6 percent year from F2020 to F2024, and that bill savings from DSM can substantially mitigate the rate impact.[289] CEC further states that rate increases could be managed if BC Hydro reduced purchases from IPPs and maximized DSM programs with a cost below the market price of energy.[290]

Changing System Need

BC Hydro states that the reduction in the rate of forecast growth was the second key factor in determining that the moderation strategy was important and that there is no need (or legislative requirement) for additional cost-effective DSM at this time.[291]

BC Hydro submits that it used a market price comparison ($36/MWh) as a screening filter to prioritize DSM investments. BC Hydro states that any DSM initiative that did not pass this screening test was investigated for modification, with the exception of the DSM initiatives specified in section 3 of the DSM Regulation. In this way, BC Hydro submits that even surplus energy resulting from DSM will have a positive impact on BC Hydro's revenue requirements because the utility cost of DSM would be less than the wholesale market price.[292]

BC energy objective 66 percent load growth target

BC Hydro states that the proposed DSM plan meets the CEA objective of reducing BC Hydro's expected increase in demand for electricity by the year 2020 by at least 66 percent.[293] BC Hydro states that the 2013 IRP DSM

[285] Exhibit B-9, BCUC IR 169.5.
[286] BC Hydro Final Argument, p. 200.
[287] BCOAPO Final Argument, p. 47.
[288] Exhibit B-9, BCUC IR 167.4
[289] CEC Final Argument, p. 14.
[290] Ibid., pp. 164, 165, 171, 172.
[291] BC Hydro Final Argument, pp. 106, 108.
[292] Exhibit B-14, BCUC IR 312.1
[293] BC Hydro Final Argument, pp. 201, 202.

levels would have reduced load growth at F2021 (mid load forecast, without LNG) by 116 percent, while the proposed DSM Plan would have reduced load growth by 106 percent.

BCSEA and CEC argue that the 66 percent target is a floor, not a ceiling, and that the 2013 IRP DSM portfolio performs better than the proposed DSM plan when compared against this objective.

Benchmarking results

The American Council for an Energy-Efficient Economy (ACEEE) 2016 State Energy Efficiency Scorecard shows that the industry average energy savings as a percent of retail sales from programs was 0.7 percent, with the following regional results: Washington 1.42 percent; Oregon 1.09 percent; California 1.95 percent.[294] BC Hydro submits that its average energy savings as a percent of retail sales from programs is 0.6 percent for fiscal 2017-2019, which BC Hydro submits is within the industry average.[295]

BCSEA submits that, while more analysis would be needed to determine what an appropriate savings target might be for BC Hydro, based on the cost-effectiveness results it would seem clear that there is considerable room to increase cost-effective savings beyond current levels.[296]

Missed opportunities

BC Hydro states that a missed or lost opportunity refers to a time-limited opportunity to cost-effectively improve energy efficiency that is lost for a period of time if not acted upon when available. BC Hydro states that in choosing between the alternative DSM plans it did not estimate the electricity savings that would be foregone through missed opportunities, however it did provide a rough estimate of missed opportunity savings.

BC Hydro estimates the opportunities risk of its DSM expenditure proposal as 10 GWh to 30 GWh over the test period, and states that programs which contribute to this estimate are the New Home program (10 GWh) and the Leaders in Energy management programs. BC Hydro considers the limited extent of missed opportunities to be reasonable. BCSEA submits that the magnitude of missed opportunities is not insubstantial.

Commission determination

The Panel finds the overall size of the funding envelope in BC Hydro's proposed DSM expenditure schedule provides a balanced response to a reduction in the load forecast and the need to meet certain targets under the 2013 10 Year Rates Plan. The Panel agrees with BC Hydro that key considerations are the changing system needs and the ability of BC Hydro to meets its rate objectives.

BC Hydro now expects to be in an energy surplus situation until F2022 (without committed resources) and F2032 (with committed resources). The Panel acknowledges concerns raised by interveners that cost-effective DSM decreases customer bills overall, but considers that, given the energy surplus situation, the use of a market priced screening filter to identify cost-effective DSM is reasonable.

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[294] Exhibit B-9, BCUC IR 176.2.

[295] BC Hydro Final Argument, p. 186.

[296] Exhibit C1-17, BCSEA response to CEC IR 1.2.4.

The Panel also considers that higher levels of DSM spending could challenge BC Hydro's ability to meet targets under the 2013 10 Year Rates Plan and place further upward pressure on the size of the rate smoothing account. In the absence of this pressure on rates, the benefits of spending more on cost-effective DSM programs would have been given greater consideration.

The Panel also considered in its deliberations the Minister's letter supporting BC Hydro's reduction in DSM spending compared to the 2013 IRP and BC Hydro's submission that it would meet the CEA objective of reducing BC Hydro's expected increase in demand by the year 2020 by at least 66 percent (even if energy savings from codes and standards are excluded). The Panel addresses BC Hydro's methodology for estimating energy savings from codes and standards in Section 3.5.6.1 of this decision.

3.5.5 Review of DSM funding levels by customer class

As part of considering the interests of persons in BC, the Panel will assess the reasonableness of the allocation DSM funding between DSM programs.

The Commission noted in the Residential Inclining Block (RIB) rate report with regard to this DSM expenditure application:

> BC Hydro recently proposed a 2 percent increase in DSM program funding for low-income residential DSM programs to $7.8 million, but a 39 percent decrease in non-low-income residential DSM programs to $30.1 million. … The Commission considers that there could therefore be the potential to increase incentives provided under of existing DSM programs, in particular for high-use customers (including low-income customers) in regions without access to natural gas, while maintaining the cost-effectiveness of the program overall.

Section 4(6) of the Demand-Side Measures Regulation states that the Commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure.

BC Hydro provided the following comparison of its DSM spend by sector:

Table 3-22: DSM Program Spend by Sector and Marginal Revenue Assumption

	Residential (including low income)	Commercial and Light Industrial	Industrial
BC Hydro Percentage of DSM program spend by sector (excluding capacity focused DSM)			
2013 IRP (F2014-F2016)	16%	36%	48%
F2014-F2016 Actual	16%	37%	47%
F2017-F2019 Forecast	14%	36%	50%
BC Hydro Percentage of DSM program spend (including capacity focused DSM) by sector			
F2017-F2019 Forecast	16%	35%	49%
Lawrence Berkeley – 2014 benchmarking study of DSM spend by sector			
DSM spend by sector	37%	61%	
BC Hydro Allocation of DSM costs for cost recovery purposes			
Allocation of DSM costs	40%	35%	25%
BC Hydro DSM expenditure as a percentage of sector revenue			
F2017-F2019 average annual DSM spend as a % of F2016 revenue	1%	3%	5%
BC Hydro marginal revenue assumption and DSM utility cost			
F2017	10.2c/kWh	8.7c/kWh	5.5c/kWh
Utility cost of F2017-F2019 DSM program	4.1c/kWh	4.2c/kWh	2.7c/kWh

BC Hydro was asked whether rate impact considerations result in preference (all else equal) for:

- DSM programs that do not reduce revenue (e.g. capacity focused DSM) over DSM programs that do reduce revenue (e.g. residential DSM programs); and
- DSM programs targeted at customers with lower c/kWh lost revenue (e.g., industrial customers) over those targeted at customers with higher c/kWh lost revenue (e.g. residential customers).

BC Hydro responded that, all else equal, the use of rate impact considerations in isolation at the program level could result in the preferences as described in the information request. However, BC Hydro submitted that it did not approach the development of the DSM Plan by considering rate impacts at the program level, but that rate impacts were considered at the portfolio level only as one of the attributes in the framework.

Position of the parties

BC Hydro states that its proposed DSM Plan maintains a broad range of measures, provides all customers with access to bill savings opportunities, and all customers have a reasonable opportunity to participate. BC Hydro further states that it did not consider the Rate Impact Measure in forming its DSM Plan, and, specifically, did not use the Rate Impact Measure to decide which DSM programs to modify or eliminate. BC Hydro states that it did, however, consider customer rate impact at a portfolio level as one of the attributes in the assessment framework. BC Hydro submits that this allowed it to create different DSM alternatives that would strike a balance across multiple attributes.

BCSEA submits that customers should have access that is not unduly limited by constrained budgets, given that it is customers who are funding the programs through their utility bills. BCSEA further submits that BC Hydro's proposed reduction in the level savings in the test period is a sole consequence of BC Hydro's exclusive focus on attempting to reduce upward pressure on rates at the expense of passing up customer bill savings of some $842 million on a portfolio basis for F2016-F2024.

CEC states that residential sector spend as a percent of revenue received is lower than the commercial and industrial sectors, however over 40 percent of cumulative energy savings in F2019 are realized by customers in the residential sector because of advancements in equipment regulations and building codes. CEC further submits that to the extent that the Commission is satisfied with the overall level of DSM spending and portfolio of savings the CEC is satisfied with BC Hydro's proposed savings by rate group.

Commission determination

The Panel recommends BC Hydro consider more targeted DSM programs directed at residential customers in the next DSM application. The Panel notes the relatively low level of DSM spending for residential customers (including low-income customers), despite DSM program utility costs that are comparable to those of BC Hydro's commercial DSM programs. The Panel further notes BC Hydro's proposed 39 percent decrease in funding for non-low-income residential programs in this Application. The Panel also notes that residential customers are allocated 40 percent of DSM program costs, but do not receive a comparable share of the DSM program funding.

3.5.6 Review of Individual programs

The Panel reviewed BC Hydro's individual programs and identified issues with the codes and standards program and capacity focused DSM program. These are considered below:

3.5.6.1 Codes and Standards

BC Hydro states that it does not approach the tracking and reporting of DSM savings from codes and standards by staking claim to a portion of the savings as exclusively BC Hydro driven. Instead, BC Hydro estimates and reports the total amount of savings anticipated to occur from the implementation of codes and standards.[297] As a result, while codes and standards represent 3.9 percent of the planned DSM expenditures, they make up 50.3 percent of the projected DSM energy savings over the test period.[298]

Subsection 4(1.4) of the Demand-Side Measures Regulation allows the Commission to attribute a portion of the avoided energy and capacity costs that will result from a code or standard to a demand-side measure that will increase the use of a regulated item. BC Hydro states that it has not included the attribution of savings under this regulation in calculating its DSM cost test results.[299]

[297] Exhibit B-10, BCSEA IR 10.1.4.
[298] Exhibit B-9, BCUC IR 184.1.
[299] Exhibit B-1-1, p. 10-29.

BC Hydro spent $6.7 million on the New Home Program in F2014-2016 at a utility cost of $60/MWh.[300] BC Hydro closed this program, stating that the program had facilitated a transition to a more cost-effective strategy that supports builder education and codes and standards development.[301]

Positions of the parties

BC Hydro supports its approach to claim all of the savings are occurring from codes and standards on the basis that this approach (i) is consistent with the approach used in the 2013 IRP, (ii) aligns with BC Hydro's load forecast and (iii) that there would be a significant time, effort and cost to quantify and defend an incremental claim.[302]

BCSEA and CEC agree with BC Hydro that Codes and Standards is a cost-effective DSM tool.[303] The CEC further submits that it would be reasonable for BC Hydro to evaluate its programs in the context of their contribution to future Codes and Standards, which are the foundation for DSM."[304]

Commission determination

The Panel directs BC Hydro, in its next DSM application, to review whether BC Hydro's approach to attributing all of the savings are occurring from the implementation of codes and standards to its codes and standards program is consistent with industry practice.

The Panel is supportive of BC Hydro's codes and standards program on the basis that it can be a cost-effective tool to achieving energy reductions. However, the Panel is concerned that BC Hydro's approach to attributing all the savings from implementing a code/standard to its codes and standards program, regardless of its level of involvement, may over-estimate the cost-effectiveness of BC Hydro's codes and standards program. If so, this could result in the under-estimation of the cost-effectiveness of other DSM programs that could, in turn, help facilitate the introduction of new codes and standards (such as the New Home Program). In addition, the Panel is concerned that this approach could distort the cost-effectiveness results of BC Hydro's DSM programs at the portfolio level.

3.5.7 DSM programs offered in Non-Integrated Areas (NIA)

Zone II and the NIA describe non-integrated communities as remote, typically lacking access to natural gas or alternative fuels (i.e. heavily reliant on electricity), with many homes with poor construction and old appliances.[305]

BC Hydro states that the Low Income Program is considered the most important to the NIA and First Nation communities, and that it is working with First Nations and remote communities to trial a number of different approaches to addressing barriers to DSM and energy efficiency upgrades (i.e. delivery of the programs).[306]

[300] Exhibit B-9, BCUC IR 172.1; 184.4; Exhibit B-15, BCOAPO IR 106.2.
[301] BC Hydro Final Argument, pp. 214, 215.
[302] Exhibit B-10, BCSEA IR 10.1.4; Exhibit B-15, BCSEA IR 51.1, 51.4.
[303] BCSEA Final Argument, p. 31, CEC Final Argument, p. 184.
[304] CEC Final Argument, p. 182.
[305] Exhibit C17-8, section 3.1.
[306] BC Hydro Final Argument, p. 184.

BC Hydro's long-term avoided cost in the Zone II areas is around double that of the integrated areas ($210/MWh vs. $100/MWh) and almost six times higher than the screening filter[307] used by BC Hydro in the integrated area ($210/MWh vs. $36/MWh). In addition, BC Hydro also would avoid GHG emissions from the NIA DSM where the avoided fuel is diesel.

BC Hydro does not track DSM spending in the NIAs, however it does track program incentives paid to residents by region. Program incentives in the NIAs were low until F2016, where they increased substantially (from about $20,000/year to $321,000/year). BC Hydro is planning to spend $2.1 million to pilot a number of different DSM approaches and activities in the First Nations and NIA communities during the test period.[308]

Using DSM incentives as an estimate of the NIAs' DSM costs, BC Hydro estimated DSM costs as a percentage of revenues during F2017-F2019 to be 2.9 percent (F2014-F2016 – 1.0 percent) in the NIAs compared to 2.6 percent (F2014-F2016) – 3.1 percent) in the integrated areas.[309]

Position of the parties

BC Hydro submits that its DSM programs are province-wide offerings because it considers energy conservation to have the same priority across the entire province. BC Hydro submits that it has made substantial increases in DSM spending in the NIAs, will continue to consider and explore new ideas and requests, and believes that its funding levels, DSM initiatives, reporting and evaluation, measurement and verification processes for NIAs and First Nations communities are reasonable and appropriate.[310] BC Hydro submits that it is already taking other actions that will more effectively increase transparency and accountability for its NIA program activities, such as obtaining NIA and Zone II interveners' ongoing feedback to improve the design, delivery and participation in DSM programs.[311] If requested by the Commission, BC Hydro states that it could add a line item to BC Hydro's Annual Report on DSM Activities to reflect the NIA activities that are tracked separately.[312]

Zone II and NIARG submits that higher priority and spending is needed for DSM in the NIAs due to the unique geographic and market barriers for participation in DSM (including affordability).[313] Zone II requests the Commission direct BC Hydro to include annual reporting on its efforts in providing DSM initiatives to Zone II and other remote communities.[314] NIARG supports the new feedback process, in combination with the addition of a line item added to BC Hydro's Annual Report on DSM Activities to reflect NIA activities.[315]

Commission determination

The Panel finds that to promote the effectiveness of BC Hydro DSM programs and ensure all customers have a reasonable opportunity to participate, BC Hydro should take into account regional variations when designing its

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[307] Exhibit B-14, BCUC IR 312.1.
[308] Exhibit B-15, Zone II IR 38.5.
[309] Exhibit B-21, BCUC IR 345.1.
[310] BC Hydro Reply Argument, pp. 120–123.
[311] Exhibit B-20, p. 47.
[312] Exhibit B-21, BCUC IR 345.2.
[313] Exhibit C17-9, BCUC IR 2.1; Zone II Final Argument, p. 14; NIARG Final Argument, p. 30.
[314] Exhibit C17-9, BCUC IR 2.2.
[315] NIARG Final Argument, p. 30.

DSM programs, such as variations in customer market barriers to energy efficiency, utility avoided costs and emissions reduction benefits. This will support the BC energy objective to "encourage communities to reduce greenhouse gas emissions and use energy efficiently."

The Panel notes the significant increase in DSM funding levels in the NIA since F2016. However, requested DSM funding levels as a percentage of revenues in the NIA over the test period are still are estimated to be similar to that of the integrated area, despite the unique market barriers of the NIA communities (including affordability), the significantly higher utility avoided fuel cost (six times higher than BC Hydro's screening filter), and additional emissions reduction benefits. The Panel is unable to determine if the proposed level of NIA DSM funding is reasonable at this time.

The Panel is persuaded that future decisions regarding NIAs would be assisted by improved metrics, including estimated differences in TRC, mTRC and UCT results for programs in NIAs compared to the integrated areas, and encourages BC Hydro to continue to work together with the NIA ratepayer groups to enhance the effectiveness of program delivery, for example as part of BC Hydro's low-income consultation group.

Regarding intervener requests for additional annual reporting of DSM in remote communities, **the Panel directs BC Hydro to include a line item in BC Hydro's Annual Report on DSM Activities to reflect the NIA activities that are tracked separately. The Panel further directs BC Hydro to include in its next DSM application:**

- **an estimate of the differences in TRC, mTRC and UCT results of BC Hydro's DSM programs available to customers in the NIAs compared to the integrated areas; and**
- **an update of whether (and if so how) BC Hydro has addressed the DSM concerns raised above by NIARG and Zone II regarding the NIAs.**

3.5.8 Evaluation, measurement and verification

BC Hydro performs its evaluation, measurement and verification (EM&V) in-house. The EM&V departments are located within Conservation and Energy Management, BC Hydro's DSM business unit. BC Hydro submits that its approach to EM&V activities is guided by industry standards and protocols and reflects a reasonable and cost-effective approach.[316]

The California Framework stipulates that program evaluations be conducted only by independent firms or organizations. In the FortisBC Inc. (FBC) 2015-2016 DSM Decision accompanying Order G-186-14 the Commission stated: "The Panel considers it is important that the overall EM&V framework addresses potential conflicts of interest that could bias the evaluation results. The Panel encourages FBC to use third party, rather than in-house, resources for EM&V where possible."

Positions of the parties

BC Hydro states that the EM&V departments are separate from, and have different managers than, the departments responsible for the development and management of DSM programs and initiatives and that independence is further maintained through the oversight processes.[317] BC Hydro submits that its draft

[316] BC Hydro Final Argument, p. 257.
[317] Exhibit B-1-1, Appendix Z, p. 11.

evaluation reports are reviewed by two external evaluation advisors on its research design, input data and analytical methods, and then further reviewed by the Evaluation Oversight Committee, which is not chaired by a Conservation and Energy Management staff person.[318]

BC Hydro states a further round of third-party review would increase costs and would not improve regulatory efficiency and that data security and the protection of customers' personal and confidential information is better assured by having BC Hydro employees work with such data.[319]

BC Hydro states that it does not follow the California Framework's stipulation that program evaluations be conducted only by independent firms or organizations as that stipulation was chosen for California's context which is different than BC Hydro's. BC Hydro states that it is a Crown corporation without an incentive mechanism for DSM and so is not in a conflict of interest with respect to the evaluation of DSM programs.[320]

NIARG submits that the Commission should be reluctant to accept BC Hydro's broad assertion that its EM&V processes are "neutral and unbiased."[321]

Commission determination

The Panel takes into account BC Hydro's decision to only engage third party evaluators to review its draft reports relating to DSM as to research design, input data and analytical methods and its position on the additional cost of engaging third party resources. The Panel is of the view that an independent assessment of the entire program could provide appropriate assurance that BC Hydro's EM&V methods are effective and unbiased. The Panel advises BC Hydro that the Commission intends to conduct its own audit or review in the future.

4.0 Other issues

4.1 Burrard facility depreciation rate

In the Application, the depreciation rates applied by BC Hydro are the same as those previously approved by the Commission, with the exception of certain property, plant and equipment at the Burrard synchronous condense facility (Burrard). BC Hydro seeks approval for depreciation rates of certain property, plant and equipment at Burrard for F2017, F2018 and F2019 as the rates prescribed by Direction No. 7 only included depreciation rates for F2015 and F 2016.[322]

Table 8-1 in the Application sets out the complete list of the proposed equipment class depreciation rates for Burrard for the test period.

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[318] Exhibit B-9, BCUC IR 191.3.
[319] Ibid., BCUC IR 191.1, 191.5.
[320] Exhibit B-9, BCUC IR 191.1.
[321] NIARG Final Argument, p. 30.
[322] Exhibit B-1-1, pp. 8-1 to 8-4.

No intervener other than Mr. Landale opposed the approval of the depreciation rates set out in the Application while BCOAPO, BCSEA and CEC[323] submit that they support BC Hydro's request.

Mr. Landale is concerned there is a lack of supporting evidence to verify the accuracy of the depreciation rates proposed for Burrard. For example, evidence to support asset selection, asset class determination, and estimated remaining life.[324]

BC Hydro submits it followed applicable accounting standards and used a standard approach for developing depreciation rates for Burrard. It classified assets into homogeneous groups of assets by the type/nature of the asset and useful life.[325] The depreciation rates for the test period are the rates required to be applied against the net book value of the assets at the beginning of each year under the assumption that all remaining assets at Burrard for the synchronous condenser function will be fully depreciated for accounting purposes by March 31, 2025. BC Hydro submitted it selected this date based on a conservative estimate of the remaining useful life of the generators, which it stated are the most significant component of the remaining assets at the facility.[326] The generating assets which are not required for synchronous condenser operation have already been fully depreciated.[327]

Commission determination

The proposed depreciation rates for BC Hydro's Burrard synchronous condense facility, as set out in Table 8-1 of the Application, are approved. This methodology is consistent with the methodology underlying the Burrard facility depreciation rates specified in Direction No. 7 for F2015 and F2016.

With regard to Mr. Landale's argument, the Panel agrees that ambiguity may arise from the use of the terms "Burrard Thermal" in Direction No. 7 and the CEA, and "Burrard Synchronous Condense Facility." The difference between the two terms suggests that only a subset of the Burrard Thermal assets is required for the Synchronous Condense facility – i.e. the boilers and related facilities may no longer be required. However, BC Hydro's evidence is that:

> The assets not required for synchronous condense operation have been fully depreciated. All remaining assets currently at the facility are required to perform and support the synchronous condenser functions. BC Hydro provided a list of the assets that, while not physically involved with the synchronous condenser function, are needed to support that function.[328]

The depreciation rates, and their underlying methodology, as set out in Direction No. 7, were approved by the Commission because the Commission was directed to do so. However, upon review in this proceeding, the Panel is satisfied that they are a reasonable basis on which to base depreciation rates for F2017, F2018 and F2019. Further, given BC Hydro's assertion that the assets not required for synchronous condensation are fully

[323] BCOAPO Final Argument, p. 38; BCSEA Final Argument, p. 38; CEC Final Argument, p. 152.
[324] Landale Final Argument, pp. 4–8.
[325] BC Hydro Final Argument, p. 172.
[326] Exhibit B-9, BCUC 152.10.
[327] Exhibit B-21, BCUC 343.2.
[328] Ibid.

depreciated, we are satisfied that the proposed depreciation rates warrant approval. We also note BC Hydro's comment that the selection of the Burrard depreciation rates does not have a material impact on the revenue requirements during the test period.

4.2 Performance metrics

Zone II requests that the Commission direct BC Hydro "to do more to manage and control costs and report on those actions and results annually."[329] In Zone II's view more can be done to manage and control costs based on some of the statistical information provided by BC Hydro during the proceeding, such as, among other things, O&M costs per customer, O&M costs per MWh and distribution and transmission cost per km.[330] Zone II further suggests that operating costs for each of the years in the RRA should be reduced by $20 million.[331]

BC Hydro submits that its forecast operating expenses for the test period are reasonable, and the evidence used by Zone II to assert that further operating cost reductions are needed are based on measures that are not appropriate for tracking employee productivity and "provide little insight into the efficiency of BC Hydro's operations…"[332] BC Hydro argues that, for example, "operating costs are not directly correlated to the number of customers, unit sales or line length."[333] BC Hydro submits that instead the metrics used the Company are "Safety, Reliability, Operational Financial and Service related metrics," and are "set to measure the Key Business Unit's individual targets, which are aligned to the Transmission and Distribution business plan and BC Hydro's overall company-wide priorities."[334] However, these metrics are "not used for productivity or benchmarking purposes."[335]

Commission determination

Aligned with the Panel's later determination in section 5.2 regarding a future performance based rate (PBR) mechanism to set rates, the Panel finds that establishing operating cost measures are fundamental to a successful PBR mechanism. At this time, the Panel is concerned with the lack of metrics used by the Company for productivity or benchmarking purposes. Although the Panel finds merit in the underlying intent of Zone II's proposal, the Panel is not convinced the proposed metrics are appropriate measures of the Company's operating efficiencies.

4.3 Powerex Net Income

BC Hydro's forecast Subsidiary Net Income is approximately ($120) million in each year of the test period as shown in Table 8-11 of the Application.

[329] Zone II Final Argument, p. 20.
[330] Ibid; Exhibit B-10, Zone II IR 1.1.
[331] Zone II Final Argument, p. 20.
[332] BC Hydro Reply Argument, p. 76.
[333] Ibid, pp. 74–75.
[334] Ibid, p. 76.
[335] Exhibit B-14, BCUC IR 245.5.

Table 4-1: Subsidiary Net Income

Table 8-11 Subsidiary Net Income

($ million)	F2015 RRA	F2016 RRA	F2017 Plan	F2018 Plan	F2019 Plan
	1	2	3	4	5
Powerex Net Income	(110.0)	(110.0)	(115.2)	(115.2)	(115.1)
Powertech Net Income	(4.2)	(5.1)	(4.5)	(4.8)	(5.1)
Total Current Subsidiary Net Income (Schedule 1.0, line 19)	(114.2)	(115.1)	(119.7)	(119.9)	(120.2)

According to Direction No. 7, section 6:

> In setting rates for the authority, the Commission must include the net income of the Authority's subsidiaries, assuming that the net income of Powerex Corp. equals trade income.

In the test period, Trade Income is forecast at $115 million per year and is reflective of Powerex's average net income over the last five years (i.e., F2012 through F2016). BC Hydro states that using a five-year average is consistent with prior revenue requirement applications and is reasonable given the year-to-year volatility in market conditions.[336]

Variances between forecast and actual Trade Income are recorded in the Trade Income Deferral Account (TIDA) ensuring that ratepayers receive the benefit of actual Trade Income in accordance with section 6 (b) of Direction No. 7:

> When regulating and setting rates for the Authority the Commission must allow the authority to continue to defer to the TIDA the variance between actual and forecast trade income.

The CEC notes that the Subsidiary Net Income was over-forecast in F2016 by about $50 million or nearly 50 percent[337] and that the historical F2015 and F2016 record has significant under-forecasting of costs and over-forecasting of revenues. Accordingly, the CEC submits that BC Hydro's forecast for Subsidiary Net Income may well represent an over-forecast in the test period and that there should be a reduction of $50 million in each year. The consequences of over-forecasting revenues and under-forecasting costs would impact deferral account forecasts for the test period and result in higher rates for BC Hydro's customers after the test period than BC Hydro is currently forecasting.[338]

BC Hydro states that the use of the five year average can be expected to result in some years that are higher than plan and some years that are lower than plan. For example in F2015, Subsidiary Net Income was approximately $10 million higher than plan. Further the total forecast for Powerex net income from F2013 to F2016 was $446 million and the actual was $435 million showing that the use of the five year average has been reasonable.[339]

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[336] Exhibit B-1-1, section 8-8.
[337] Ibid., Appendix A Financial Schedules, p. 2 of 70.
[338] CEC Final Argument, p. 153.
[339] BC Hydro Reply Argument, p. 98.

Commission determination

The Panel supports BC Hydro's methodology of using the last five year average for forecasting its Trade Income.

The Panel notes that Powerex's net income has fluctuated considerably in the past ten years from a high of $259 million in F2007 to a low of $7.5 million in F2010. Volatility of this nature makes forecasting very difficult. Although the CEC identified the years in which the forecast was higher than the actual, the Panel also recognizes that in some other years, the forecast was lower than actual. Over the past five years the cumulative variance is approximately $11 million with both positive and negative variances.

Reducing the forecast by $50 million in each of the test periods, as suggested by the CEC, would result in a cumulative increase in the Rate Smoothing Regulatory Account of $150 million. If the actual Powerex Net Income is $50 million less than forecast, the TIDA would increase by $150 million. Either way, ratepayers will only benefit from the actual Powerex Net Income.

4.4 Transmission Revenue Requirement and Open Access Transmission Tariff

BC Hydro's Transmission Revenue Requirement (TRR) is the sum of its net transmission related costs as calculated using a cost of service methodology, and using an allocation or direct assignment of costs. This methodology is consistent with the method used in its previous revenue requirement applications as well as the method previously used by the British Columbia Transmission Corporation.[340] Table 9-1 in the Application outlines BC Hydro's TRR for the years F2015 to F2019:

[340] Exhibit B-1-1, pp. 9-1 and 9-2.

Table 4-2: Transmission Revenue Requirement

		F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
		1	2	3	4	5	6	7
1	Operating Cost	367.4	383.3	366.8	371.1	417.1	407.8	396.3
2	Taxes	126.1	123.7	132.0	128.5	137.6	141.7	147.2
3	Amortization	158.9	184.6	187.1	184.9	216.9	230.3	240.9
4	Finance Charges	167.0	182.1	233.0	241.7	180.3	187.9	199.0
5	Return on Equity	163.1	177.7	209.0	218.0	243.6	250.8	250.1
6	Business Support Cost	96.1	95.2	115.0	126.4	119.0	97.2	103.0
7	**Internal Allocations to Transmission**:							
8	Generation Ancillary Services	1.8	1.3	1.8	1.9	2.5	2.5	2.5
9	Capital Infrastructure Project Delivery	61.6	58.2	61.7	46.4	37.5	36.5	36.5
10	Adjustment to offset re-org impact	(24.2)	-	(24.0)	-	-	-	-
11	**Gross Transmission Costs**	1,117.9	1,206.1	1,282.5	1,319.0	1,354.4	1,354.7	1,375.5
12	**Less Internal Allocations from Transmission**							
13	Generation Related Transmission Assets	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)
14	Substation Distribution Assets	(123.2)	(115.3)	(148.3)	(121.2)	(125.0)	(128.5)	(126.1)
15	Generation Real Time Dispatch	(1.7)	(1.7)	(1.8)	(1.8)	(1.6)	(1.5)	(1.6)
16	Distribution Real Time Dispatch	(16.7)	(16.7)	(17.1)	(17.1)	(16.7)	(16.2)	(16.6)
17	Aboriginal Relations and Negotiations	(19.4)	(19.6)	(19.3)	-	-	-	-
18	Technology and Customer Service	(184.2)	(185.6)	(185.9)	(185.1)	(214.7)	(212.2)	(211.6)
19	**Less Miscellaneous Revenues**							
20	Secondary Revenues	(7.4)	(8.8)	(7.5)	(6.2)	(5.1)	(5.1)	(5.0)
21	Amortization of Contributions	(8.1)	(9.5)	(10.9)	(13.7)	(13.6)	(14.2)	(14.4)
22	Fortis General Wheeling Agreement	(5.0)	(5.0)	(4.8)	(4.8)	(4.7)	(4.9)	(5.0)
23	Interconnections	(4.0)	(10.6)	(4.2)	(4.3)	(3.0)	(1.9)	(1.9)
24	**Subtotal**	(413.2)	(416.2)	(443.1)	(397.5)	(427.7)	(427.9)	(425.4)
25	**Transmission Revenue Requirement**	704.7	789.9	839.4	921.5	926.7	926.8	950.1

BC Hydro's rates charged under its Open Access Transmission Tariff (OATT) are to recover its TRR for the following services:

1. Network Integration Transmission Service;
2. Point-To-Point Transmission Service; and
3. Ancillary Services.[341]

Of the total TRR collected under the OATT, approximately 1.5 percent is collected from customers external to BC Hydro and Powerex.

BC Hydro states that the proposed F2017 OATT rates are higher than the interim F2017 OATT rates approved in Order G-40-16 and explains that the increase in the TRR of $16.2 million is mainly due to a larger growth in the transmission asset base compared to the substation distribution asset base. The F2017 interim rate was based on the F2015 actual assets in service while the F2017 forecast set out in the Application is based on the F2016 actual assets in service. This growth in the transmission asset base resulted in a cost shift of $17.8 million when the allocation factors were recalculated.[342]

[341] Ibid., p. 9-15.

[342] Exhibit B-10, TCE IR 1.1.1.

The interim and proposed OATT rates are show in Table 9-8 of the Application and reproduced below:

Table 4-3: Interim and Proposed OATT Rates for Fiscal 2017 to Fiscal 2019

	Rate Schedule	Rate Class	Reference	F2017 Interim[62]	F2017 Plan	F2018 Plan	F2019 Plan
				1	2	3	4
1	Attachment H	**NITS Revenue Requirement ($)**	Schedule 3.4 L35	805,500,000	823,300,000	821,500,000	842,000,000
2	RS 00	**NITS Monthly Rate ($)**	Schedule 3.4 L36	67,125,000	68,608,333	68,458,333	70,166,667
3	RS 01	**Long Term Firm Point-to-Point**					
4		Yearly - $/MW of Reserved Capacity per year	Schedule 3.4 L44	69,455	70,687	71,738	73,397
5		**Short Term Firm and Non-Firm Maximum Price for Delivery**					
6		Monthly - $/MW of Reserved Capacity per month	Schedule 3.4 L45	5,787.91	5,890.60	5,978.14	6,116.40
7		Weekly - $/MW of Reserved Capacity per week	Schedule 3.4 L46	1,335.67	1,359.37	1,379.57	1,411.48
8		Daily - $/MW of Reserved Capacity per day	Schedule 3.4 L47	190.29	193.66	196.54	201.09
9		Hourly - $/MW of Reserved Capacity per hour	Schedule 3.4 L48	7.93	8.07	8.19	8.38
10	RS 03	**Scheduling, System Control and Dispatch Service ($)**					
11		per MW of Reserved Capacity per hour	Schedule 3.4 L51	0.099	0.105	0.099	0.099

BC Hydro proposes to recover the difference between the final F2017 OATT rates approved by the Commission and the interim rates through a one-time charge to Transmission Customers. This charge would be based on actual volumes of Transmission Services multiplied by the difference between the applicable final OATT rate and the applicable interim rate.[343]

BCOAPO and CEC agree that the difference between the proposed and the interim F2017 OATT are appropriately recovered through a one-time charge to Transmission Customers. Although TransCanada Energy is an external customer and asked a series of IRs on the OATT, they did not file a Final Argument. No other intervener raised issues with the TRR or the OATT proposed by BC Hydro.

The requested final OATT rates for F2017-F2019 are set out in Appendix T of the Application, and as corrected in Errata No. 1 (Exhibit B1-2), with the exception of the OATT rates for F2019 for which BC Hydro has requested in its Amended Application be unchanged from its 2018 OATT rates.

[343] Exhibit B1-1, p. 9-1.

Commission determination

The Panel approves the OATT as proposed by BC Hydro in its Application and as corrected in Errata No. 1 for F2017 and F2018. The request in its Amended Application regarding the F2019 OATT rates is dealt with in section 5.1 of the Decision. The Panel also approves the proposed method to apply a one-time charge to Transmission Customers for the difference between the proposed and the interim F2017 OATT. The Panel finds BC Hydro's explanations for its Transmission Revenue Requirements to be reasonable and the method for calculation of the OATT is consistent with the methodology previously approved by the Commission.

5.0 Panel discussion and determinations on rate increases

5.1 Amended Application and the 2013 10-Year Rate Plan

In November 2013, BC Hydro and the Minister of Energy and Mines announced the 2013 10 Year Rates Plan for BC Hydro to balance the objectives of keeping rates as low as possible while funding needed investments.[344] The Rates Plan was built on the basis of average rate increases of 2.6 percent in the last five years of the plan from F2020 to F2024, a Rate Smoothing Regulatory Account to capture the unrecovered portion of the approved revenue requirements in the earlier years of the Rates Plan and full recovery of the balance in the Rate Smoothing Regulatory Account in the later years of the Rates Plan.[345]

Exhibit B-15, BCSEA IR 2.64.1 outlines the statutory framework underlying the 2013 10 Year Rates Plan, which includes various Government Directives and Orders in Council (OIC) concerning, among other matters, BC Hydro's rate increases and dividend payments to the Province.

BC Hydro submits that it:

> …has taken appropriate and significant steps to manage costs and focus on important priorities during the test period, given the context of the 2013 10 Year Rates Plan and the Minister's Mandate Letter of Expectations. The Commission will review BC Hydro's rates and revenue requirements and deferral account balances for fiscal 2020 to fiscal 2024 in future proceedings, making it unnecessary for the Commission to make findings at this time regarding BC Hydro's progress towards achieving the 2013 10 Year Rates Plan rate targets for years after the test period. BC Hydro expects to file its next revenue requirements application prior to fiscal 2020.[346]

The rates applied for in the Application are consistent with the Rates Plan and are the maximum allowable under Direction No. 7. However, on November 8, 2017, BC Hydro, pursuant to sections 58-60 of *the Utilities Commission Act*, amended its requests as they relate to fiscal 2019 (Amended Application) as follows:

i. Change the requested rate increase for fiscal 2019 from 3 percent to 0 percent, and

[344] Exhibit B-1-1, p. 1-16.
[345] Ibid, p. 1-2.
[346] BC Hydro Argument, p. 25.

ii. Request that Open Access Transmission Tariff (OATT) rates for fiscal 2019 remain unchanged from fiscal 2018.[347]

With regard to the Amended Application, BC Hydro submits:

> The amendment of the fiscal 2019 rate increase from 3 per cent to 0 per cent is aligned with the Mandate Letter from Government. Since the development of the 2013 10 Year Rates Plan, both the Province and BC Hydro have taken action to keep our rates low and in line with the Plan. The Province and BC Hydro are committed to take further actions as required as part of the comprehensive review of BC Hydro that is expected to begin in fiscal 2018 and is likely to be completed in fiscal 2019. The comprehensive review of BC Hydro and refreshed plan for rates are expected to inform revenue requirement applications for subsequent fiscal years beginning in fiscal 2020.[348]

BC Hydro argues that significant weight should be given to "the evidence of Government policy favouring a rate freeze". Specifically it states:

1. The Minister's Mandate Letter is a clear expression of government policy.
2. The Commission is free to give significant weight to Government policy, as the Commission has done in the past.
3. The rate freeze can be implemented while respecting other regulatory principles.

BC Hydro argues that "[t]he Minister's Mandate Letter, echoing the new Government's platform, includes an unequivocal direction to freeze rates. It expresses the new Minister's expectation that BC Hydro will work with the Ministry of Energy, Mines and Petroleum Resources "to freeze rates and develop a refreshed plan to keep electricity rates low and predictable over the long-term while making significant investments to expand the system and maintain aging infrastructure."[349]

With respect to the 2013 10 Year Rates Plan, BC Hydro explains that it will be able to meet this target due to 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
- Targeting renewal of expiring Independent Power Producer contracts at less than what they are currently paid
- Government changes to significantly reduce pressures on BC Hydro's rates such as eliminating the Tier 3 water rates in F2018, changing the calculation on the ROE and reducing the dividend.[350]

[347] Exhibit B-23, p. 1.
[348] Ibid., p. 3.
[349] BC Hydro Final Argument, December 21, 2017, p. 2.
[350] Exhibit B-10, CEABC IR 3.4.

As a result of the above steps, BC Hydro submits it is not forecasting large annual increases in major cost categories such as depreciation, finance charges, return on equity (net income) and cost of energy during the latter part of the period covered by the 2013 10 Year Rates Plan period (i.e., fiscal 2020 through fiscal 2024).[351]

Throughout the Application, there are numerous references to the government's 2013 10 year rates plan, along with BC Hydro submission on the efforts undertaken and steps to reduce costs in order to meet certain objectives.[352] In this regard BC Hydro submits that it has already made a "significant effort to manage and control costs" and that the forecast revenue requirements represent its "reasonable cost of investing in the system and providing safe and reliable service to customers in the test period."[353]

Intervener arguments

Many interveners have expressed concerns with BC Hydro's ability to meet its 10 Year Rates Plan, with particular concern towards the Rate Smoothing Regulatory Account, and the effect that the Amended Application will have on the RSRA, if approved.

AMPC

AMPC raises concerns related to BC Hydro's rate increases pose risk to the industrial load forecast. AMPC is already concerned that BC Hydro's load and revenue forecast is "overly optimistic given its track record, the way it understates industrial customers' price sensitivity and risk, and how it forecasts growth in certain sectors."[354]

AMPC urges the Commission "to ensure, through careful scrutiny, that BC Hydro does not exceed the proposed $795 million addition to its rate-smoothing account over F2017-F2019, for collection during the F2020-F2024 period."[355]

With respect to the Amended Application, AMPC recommends the Commission approve the rate freeze through a corresponding reduction to BC Hydro's revenue requirement.[356] This will mean the balance in RSRA will not be increased as a result of the Amended Application and it would "drive [BC Hydro] to find operational efficiencies and cost reduction opportunities, diminishing intergenerational equity concerns through an efficient price signal."[357]

McCandless

McCandless submits the RSRA is the key to the 2013 10 Year Rates Plan in that it allows the government to set annual electricity rate increases at less than the forecasted increase in costs.[358]

With respect to the Amended Application, McCandless notes its concern that the resulting "foregone revenue would be added to the [RSRA], and increase the debt liability faced by future customers."[359]

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[351] Ibid.
[352] Exhibit B-10, AMPC IR 1.1; AMPC IR 1.6; NIARG IR 1.1; Exhibit B-9, BCUC IR 124.11
[353] BC Hydro Final Argument, para. 583.
[354] AMPC Final Argument, para. 2(c).
[355] Ibid., para. 12
[356] AMPC January 15, 2018 Final Argument, para. 2; para. 3.
[357] Ibid., para. 2(b).
[358] McCandless Final Argument, pp. 3–4.

NIARG

NIARG is concerned about the amount of the cumulative increase which is "exacerbated by the effects of transferring a portion of the forecast revenue requirements to the RSRA for subsequent recovery in the final years of the 2013 10 Year Rates Plan."[360]

NIARG states that customers in the Non-Integrated Areas (NIAs) of BC Hydro's service territory are highly reliant on electric service since they typically do not have access to natural gas or other alternative fuels and as a result the higher cost of service with "the daunting collection of a large Rate Smoothing Regulatory Account deferral balance in just a few years, is more worrisome in the absence of any economic alternative energy sources."[361]

NIARG submits while rate smoothing can be an apparent benefit in the short-term when rates are lower than they might otherwise be, the potential downside may be more significant if recovery of amounts in future years unfortunately coincide with lower-than anticipated revenues and/or higher-than-anticipated costs. [362]

With respect to the Amended Application, NIARG has concerns regarding "under-recovery of the F2019 revenue requirement and the perils of indefinite deferral."[363]

MoveUp

MoveUp argues the 2013 10 Year Rates Plan enables the BC Government to suppress rates below what was needed to meet BC Hydro's financial requirements and payment of the dividend to the Province.[364]

MoveUp also raises concerns that BC Hydro forecasts zero additions to the Cost of Energy Variance Accounts in the test period.[365] MoveUp submits that it considers it "highly likely that BC Hydro will continue to experience unfavourable variances in the test period and beyond, and notes that BC Hydro's response to BCUC 1.124.8 makes it clear that with unfavourable variances equal to the five year average, the balance does not get significantly reduced by F2024 with the DARR frozen at 5%."[366]

BCOAPO

BCOAPO expresses a number of concerns related to the 2013 10 Year Rates Plan and states:

- We are at the mid-point of the 10 Year Plan and retirement of the amounts owing in the RSRA is a "fast-approaching and daunting inevitability;"[367]
- An "air of complacency" has developed regarding the use of BC Hydro's regulatory accounts;
- There is an apparent perception that the 10 Year Rates Plan stretches far enough into the future that we can take comfort in BC Hydro's assertion that the regulatory account balances will be reduced to $3.6

[359] McCandless January 11, 2018 Final Argument, p. 1.
[360] NIARG Final Argument, para. 4.
[361] Ibid., para. 5.
[362] NIARG Final Argument, para. 15.
[363] NIARG January 15, 2018 Final Argument, para. 3.
[364] MoveUp Final Argument, p. 2.
[365] Ibid., p. 9.
[366] Ibid., p. 10.
[367] BCOAPO Final Argument, para. 27.

billion (a massive figure),the Rate Smoothing Account cleared to zero by F2024 and the target rate increases for the last 5 year of the 10 Year Rate Plan (F2020-F2024) of 2.6 percent per annum are expected to fully recover the balances in the RSRA by the end of F2024;"[368]

- 2024 is not that far away and given these figures, BCOAPO's economically vulnerable constituents are understandably fearful of rate increases in the long term and specifically of what will happen after 2024 at the conclusion of the 10 Year Rates Plan "when the piper must be paid."[369]

BCOAPO also submits that the Commission must be particularly vigilant in ensuring that BC Hydro is engaging in all activities that will allow it to reach its target while balancing this goal with concerns regarding rate shock as this is entirely in the public interest.[370] As an overarching consideration, BCOAPO submits any revenue requirements the Commission approves over the rates cap will not be paid by ratepayers in the test period, but will be paid by ratepayers in the not too distant future.[371]

With respect to the Amended Application, BCOAPO notes its concern that "There is no guarantee that the outcome of the refreshed rates plan and the completion of another review of BC Hydro will include a reduction in BC Hydro's annual revenue requirement either by $142.3 million per year or at all."[372]

CEC

CEC submits that to the extent that the BC Hydro over forecasts its load, anticipates revenues that do not materialize and if BC Hydro's cost structure increases, the RSRA could have greater than anticipated additions to the account."[373] CEC also submits the proposed additions to the RSRA are forecast to be quite significant and could impose a substantial burden on future ratepayers.[374]

CEC submits that "it is important that BC Hydro undertake to control its expenditures to the greatest extent possible at this time to minimize future rate increases and mitigate the impacts to intergenerational inequity."[375] With respect to the Amended Application, in CEC's view it should only be approved on a permanent basis when there is evidence that it can be supported by "permanent long-term revenue requirement reductions."[376]

FortisBC

With regard to the weight that should be given to the Minister's Mandate Letter as an expression of Government policy, Fortis BC "acknowledges and agrees that government policy is a factor that can be taken into account in proceedings before the Commission. FortisBC itself has referred in past proceedings to government policy and believes that consideration of government policy is appropriate".

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[368] Ibid., para. 129.
[369] Ibid., para. 132.
[370] Ibid.,, para. 133.
[371] Ibid., para. 218.
[372] BCOAPO January 15, 2018 Final Argument, para. 11.
[373] CEC Final Argument, para. 722
[374] Ibid., para. 15
[375] Ibid.,, para. 16
[376] CEC January 15, 2018 Final Argument, para. 48.

However, FortisBC argues that '[t]he Commission may consider numerous factors in determining the weight that should be given to a given government communication." FortisBC describes these factors as follows:

1. the means by which the government has expressed the policy at issue;
2. the capacity in which the government has made its views known;
3. the content of the government statement that the Commission has been asked to consider; and
4. the nature and stage of the proceeding in which that government communication might be considered.[377]

With regard to (1), above, Fortis BC submits that:

> The enactment of legislation, the making of a regulation, and the making of a direction under s. 3(1) of the *Utilities Commission Act* are all means of communication by the government to which the Commission is required to accede. For example, s. 3(2) of the *Utilities Commission Act* commences: "The commission must comply with a direction issued under subsection (1)..." By contrast, general policy statements not captured in a statute, regulation or s. 3(1) direction are not binding, and in fairness BC Hydro has not suggested that the Mandate Letter is. In one proceeding the Commission accepted "the view that the Act accords general policy statements of government no more weight than any other evidence brought before it, unless the policy statement is given the weight of a direction or special direction under Section 3(1) or 3.1 of the Act.

BC Hydro reply

BC Hydro states that other than Zone II and McCandless, interveners take no issue with approvals sought regarding deferral and regulatory accounts.[378]

BC Hydro does not accept BCOAPO's statement that an air of complacency exists surrounding deferral accounts and states it is "on track to significantly reduce the balance of these accounts," noting that by the end of 2023, total deferral balances will be reduced by 40%.[379]

BC Hydro responds to McCandless stating that a mechanism to recover deferral accounts in the test period is not required since recovery will take place after the test period.[380]The company further states that it does not accept that it will be unable to recover the RSRA with rate increases of 2.6% in fiscal periods 2020 to 2024. BC Hydro states they have properly addressed deferral recovery in their forecasts[381]and that it meets all applicable accounting standards.[382]

With respect to the Amended Application, BC Hydro states that it still plans to fully recover the balance in the RSRA within five years of the proposed rate freeze, which "avoids any truly 'intergenerational' impacts," and

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[377] FortisBC January 15, 2018 Final Argument, pp. 9–13.
[378] BC Hydro Reply Argument, Paragraph 174, p. 84.
[379] Ibid., pp. 84–85.
[380] Ibid., p. 89.
[381] Ibid., pp., 89–91.
[382] Ibid., p. 91.

fulfills the mandate under Direction No. 7 that the Commission must allow the RSRA be cleared from time to time and within a reasonable period.[383]

Furthermore, "A planned comprehensive review of BC Hydro will target potential offsetting cost savings that would impact rates after the current test period."[384] Parties "will have the opportunity to evaluate the comprehensive review and refreshed rates plan in BC Hydro's next revenue requirements application."[385]

BC Hydro includes the following points in its reply to FortisBC's submissions on the expression of government policy:

- The Mandate Letter is clear and unequivocal in calling on BC Hydro to "Freeze BC Hydro rates and develop a refreshed plan."
- The policy was made known by BC Hydro's shareholder, the provincial Government, in the Mandate Letter and in the news release and comments in the Legislature made on the date that BC Hydro filed its Rate Freeze Amendment Application. All of these communications come from the Minister responsible for the *Hydro and Power Authority Act* and energy policy in the province generally.
- The policy to "Freeze BC Hydro Rates" is clear. That the expectation is described concisely does not detract from its weight. The content of the policy was also explained through other means by the Minister in the news release and comments in the Legislature made on the date that BC Hydro filed its Rate Freeze Amendment Application.
- The impact of the rate freeze will be an immediate positive benefit to ratepayers. Future rate impacts due to the deferring of costs in the Rate Smoothing Regulatory Account may be offset by the results of the comprehensive review of BC Hydro and the refreshed rates plan.[386]

Commission determination

The common theme in the Application and supporting evidence centers around BC Hydro's submission that it has already undertaken, and will continue to take, steps to achieve the targets of the 2013 10 Year Rates Plan. This includes the restructuring, prioritizing capital spending, undertaking Workforce Optimization, reducing costs and making changes to its energy portfolio; while any transfers to the Rate Smoothing Regulatory Account over this test period will be recovered over the remaining years of the 2013 10 Year Rates Plan.[387]

It is BC Hydro's submission that despite lower forecast revenues associated with the emergence in 2015 of a slower rate of load growth, it is on track to achieve objectives of the 2013 10 Year Rates Plan because it has: a) intensified efforts to manage costs; and b) prioritized spending in the test period in a manner consistent with the Minister's Mandate Letter.[388]

Further, when asked what factors could take BC Hydro "off track" from achieving the 10-Year Rate Plan objective of reducing the RSRA balance to zero by F2024, BC Hydro noted that it did not currently anticipate any factors

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[383] BC Hydro December 21, 2017 Final Argument, p. 11.
[384] Ibid., para. 1.
[385] BC Hydro January 19, 2018 Reply Argument, para. 19.
[386] Ibid., pp. 3–7.
[387] Exhibit B-1-1, page 1-18.
[388] BC Hydro Final Argument, p. 19.

that would put it off track but it would continue to take actions, working with Government, to remain on track by adapting to changing circumstances and challenges. However, BC Hydro did note the following factors that could positively or negatively impact its ability to achieve the 10-Year Rates Plan: weather, industrial load, LNG load, interest rates, and energy markets.[389]

In the Site C Inquiry, the Commission found there will be considerable upward pressure on rates for the remainder of the 2013 10 Year Rates Plan and beyond fiscal 2024. The Commission further found the risk associated with this upward pressure on rates is especially concerning given the submissions related to potential "demand destruction" that could result from the impact of real rate increases on already vulnerable industrial customers and the likelihood that even nominal rate increases will increase energy poverty among BC's low income households. [390]

The Panel recognizes that many interveners in this proceeding have raised concerns with respect to BC Hydro adherence to the 2013 10-year rate plan and in particular, concerns specific to the use of the RSRA. The Panel acknowledges BC Hydro's argument that the original application does not require that the Commission make findings on its "progress towards achieving the 2013 10 Year Rates Plan rate targets for years after the test period."[391] However, in its Final Argument on the Amended Application, BC Hydro submits that "the financial implications of BC Hydro's requested rate freeze must be viewed in the context of … the steps BC Hydro is taking to eliminate the balance in the Rate Smoothing Regulatory Account by the end of Fiscal 2024 and reduce regulatory account balances overall". While it previously argued that it is "is on track to significantly reduce the balance in its accounts during the remaining years of the 2013 10 Year Rates Plan."[392]

Given the importance of this theme, the Panel first considers it appropriate to review the 2013 10 Year Rates Plan including the forecast reduction in the RSRA in keeping with annual rate increases to 2.6 percent in later years and assess the risks that BC Hydro may face in meeting this goal. The Panel's observations on the RSRA and the risks to achieving the 2013 10 Year Rates Plan will inform its decision on the Amended Application.

The Rate Smoothing Regulatory Account

As a result of the 2013 10 Year Rate Plan the RSRA was implemented to keep rate increases as gradual and predictable as possible by spreading costs that occur in the earlier years of the 2013 10 Year Rate Plan over the later years of the Plan.[393]

When the 10 Year Rate Plan was first formulated the RSRA was forecast to peak at $1,088 million in F2020 and be fully recovered in the last four years of the Plan.[394] Changing circumstances, such as forecasting approximately $3.5 billion less revenue compared to the forecast when the 10 Year Rate Plan was introduced, have resulted in RSRA balances that differ from those originally forecasted.[395]

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[389] NIARG IR 1.1.1.
[390] Site C Final Report, pp. 81–82.
[391] BC Hydro Final Argument, p. 25.
[392] BC Hydro December 21, 2017 Final Argument, pp. 11,12.
[393] Exhibit B-1-1, pp 7-43 and 7-44.
[394] Exhibit B-10, AMPC IR 1.1.1.
[395] Exhibit B-10, CEA IR 1.3.2.

Table 5-1: Rate Smoothing Regulatory Account Forecast Additions and Recoveries[396]

Rate Smoothing $ million	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan	F2020 Forecast	F2021 Forecast	F2022 Forecast	F2023 Forecast	F2024 Forecast
Beginning of Year	166.2	287.4	497.4	783.3	1,082.7	1,490.7	1,589.4	1,285.8	732.5
Additions/(Recovery)	121.2	210.0	285.9	299.4	408.0	98.7	(303.6)	(553.3)	(732.5)
End of Year	287.4	497.4	783.3	1,082.7	1,490.7	1,589.4	1,285.8	732.5	-

As set out in the table above, and in accordance with Direction No. 6, actual additions to the RSRA account in F2015 and F2016 were $166.2 million and $121.2 million, respectively, in order to achieve a rate increase of 9.0 percent in F2015 and 6.0 percent in F2016.[397] Forecast additions in F2017-F2019 are $210.0 million, $285.9 million and $299.4 million, respectively, in order to achieve rate increases of 4.0%, 3.5% and 3.0% respectively, in accordance with Direction no. 7. BC Hydro states that it is on track to reduce the balance of the RSRA account to zero by F2024, and is not requesting approval of a recovery mechanism for the account."[398]

In order to meet the 10 Year Rate Plan for annual 2.6% increases in the latter years, the Panel observes that incremental additions to the RSDA are anticipated in the years after the current test period with the balance peeking in F2021 at approximately $1.6 billion, excluding any adjustments that result from directives in this decision. The Panel is concerned that if BC Hydro does not stay on track in terms of clearing the RSRA by 2024, ratepayers will see higher rate increases than is anticipated in the 10 year rate plan and reasonable returns to the shareholder may not be possible without affecting BC Hydro's long term sustainability.

BC Hydro states that the rate freeze for F2019 will add approximately $140 million to the RSDA. Given this incremental addition, the Panel finds the rate freeze, if implemented, would pose an additional material risk to the 10 year rate plan.

The Panel agrees with interveners that there are risks associated with the recovery plan for the RSRA.

Forecast Balances of other Regulatory Accounts

In the Table below, BC Hydro shows actual regulatory account balances for F2012-F2016, along with forecast balances in each account up to F2024:

[396] Exhibit B-10, Zone II, IR 1.4.1.

[397] Exhibit B-1-1, page 7-43.

[398]Exhibit B-1-1, p. 7-44.

Table 5-2: Actual and Forecast Regulatory Account Balances (as at 2016) [399]

	$ million	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan	F2020 Forecast	F2021 Forecast	F2022 Forecast	F2023 Forecast	F2024 Forecast
	Cost of Energy Variance Accounts													
1	Heritage Deferral Account	244	70	105	165	(24)	(20)	(16)	(11)	(7)	(4)	(2)	(1)	(1)
2	Non-Heritage Deferral Account	367	468	362	524	917	771	613	440	253	136	75	55	33
3	Trade Income Deferral Account	175	190	325	245	250	210	167	120	69	37	21	15	9
	Total	786	728	791	933	1,143	961	764	549	316	170	94	69	42
	Other Cash Variance Accounts													
4	Storm Restoration Costs	1	(3)	(3)	8	30	20	10	0	-	-	-	-	-
5	Amortization of Capital Additions	(2)	(6)	(4)	(4)	(10)	(6)	(3)	0	-	-	-	-	-
6	Total Finance Charges	6	1	(79)	(173)	(306)	(204)	(102)	0	-	-	-	-	-
7	Rock Bay Remediation	4	29	49	20	(27)	(18)	(9)	0	-	-	-	-	-
8	Arrow Water Systems	8	8	9	4	0	0	0	0	-	-	-	-	-
9	Asbestos Remediation	-	8	17	10	5	3	2	0	-	-	-	-	-
10	Home Option Purchase Plan	20	21	22	11	0	0	0	0	-	-	-	-	-
11	Real Property sales	-	-	-	8	18	25	16	2	-	-	-	-	-
12	Minimum Reconnection Charges	N/A	N/A	N/A	N/A	1	(0)	(0)	(0)	-	-	-	-	-
13	Mining Customer Payment Plan	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	-	-	-	-
	Total	36	59	13	(115)	(290)	(180)	(87)	2	-	-	-	-	-
	Non-Cash Variance Accounts													
14	Foreign Exchange Gains/Losses	(103)	(100)	(89)	(71)	(69)	(63)	(32)	3	1	2	3	3	3
15	Non-Current Pension Costs	55	544	280	564	691	306	274	243	211	179	147	114	82
16	Debt Management	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	-	-	-	-
	Total	(49)	444	191	493	622	242	242	246	212	181	150	117	85
	Benefit Matching Accounts													
17	Demand-Side Management	638	732	788	841	907	932	996	991	968	942	915	886	854
18	First Nations Costs	153	168	173	151	133	131	120	101	82	62	43	24	5
19	Site C	181	258	338	419	436	453	472	491	511	531	551	572	593
20	Future Removal & Site Restoration	(120)	(87)	(55)	(33)	(9)	-	-	-	-	-	-	-	-
21	Pre-1996 Contributions in Aid of Constructic	67	75	81	87	92	91	88	83	78	73	68	63	58
22	Smart Metering & Infrastructure Program	92	192	276	283	283	261	239	217	196	174	152	130	109
23	Capital Project Investigation Costs	44	40	35	30	25	20	15	10	6	1	(0)	-	-
	Total	1,055	1,377	1,636	1,779	1,867	1,889	1,930	1,894	1,840	1,783	1,730	1,674	1,618
	Non-Cash Provisions													
24	First Nations Provisions	391	386	416	413	409	399	396	401	406	411	415	420	425
25	Arrow Water Systems Provision	4	3	4	4	5	3	3	3	2	2	2	2	2
26	Environmental Provisions	230	331	317	352	381	338	302	267	231	203	186	169	155
	Total	625	720	737	770	794	740	700	670	639	615	604	591	582
	Rate Smoothing Accounts													
27	Waneta (closed)	40	25	15	-	-	-	-	-	-	-	-	-	-
28	F2010 ROE Adjustment (closed)	34	23	11	-	-	-	-	-	-	-	-	-	-
29	F12-F14 Rate Smoothing (closed)	(70)	(111)	-	-	-	-	-	-	-	-	-	-	-
30	Rate Smoothing	-	-	-	166	287	497	783	1,083	1,491	1,589	1,286	733	-
	Total	4	(63)	26	166	287	497	783	1,083	1,491	1,589	1,286	733	-
	IFRS Transition Accounts													
31	IFRS Pension	-	723	688	650	612	574	535	497	459	421	382	344	306
32	IFRS PP&E	222	447	617	758	873	962	1,025	1,064	1,079	1,071	1,039	1,007	976
	Total	222	1,170	1,306	1,409	1,485	1,535	1,561	1,562	1,538	1,491	1,421	1,352	1,282
33	Total Regulatory Account Balance	2,679	4,434	4,699	5,434	5,908	5,685	5,894	6,006	6,035	5,830	5,284	4,536	3,609
34	Annual change % of Reg. Acct. Balance		66%	6%	16%	9%	(4%)	4%	2%	0%	(3%)	(9%)	(14%)	(20%)
35	Total Interest on Regulatory Accounts	48	55	57	67	73	76	68	60	49	40	33	30	28

BC Hydro forecasts the total balance of the regulatory accounts will be reduced by approximately 40 percent or $2.4 billion at the end of the 2013 10 Year Rate Plan period (from $6.0 billion at the end of F2019 to $3.6 billion at the end of F2024) based on existing regulatory mechanisms and those proposed with the Application.

[399] Exhibit B-9, BCUC IR 124.2.

The Panel points to BC Hydro's explanation that "while it is accountable for achieving the forecast reduction, [its] ability to do so is also subject to a number of variables beyond BC Hydro's control."[400] The Panel notes that BC Hydro's assertion is based on a number of assumptions and even by the Company's own analysis, the actual balances will be different than presented in its forecast for a number of reasons.[401]

Amortization of these regulatory accounts is included in BC Hydro's revenue requirement, which is then recovered from customers in their rates. From F2015 through F2019, rates have been insufficient to recover the revenue requirement. The net result is that some or all of the amortization of these deferral accounts accumulates in the RSRA, or another regulatory account.

There have been several risks to the 2013 10 Year Rates Plan identified and the Panel reiterates that these risks could potentially result in the inability of BC Hydro to reduce or eliminate the balances in some or many of its deferral and other regulatory accounts.

Cost of Energy (COE) Variance Accounts (NHDA and HDA)

When the 2013 10 Year Rates Plan was announced, the following projections for 2015 to 2024 were provided:

Table 5-3: 2013 10 Year Rates Plan Projections[402]

	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024
Rate Increase (%)	9.0	6.0	4.0	3.5	3.0	2.6	2.6	2.6	2.6	2.6
Return on Equity (%)	11.84	11.84	11.84	11.40	10.91	10.59	10.49	10.51	10.50	10.42
Net Income ($ million)	582	652	701	715	730	746	761	777	794	810
Water Rentals ($ million)	393	382	391	345	375	383	392	399	409	416
Grants & Taxes ($ million)	214	221	230	241	249	260	268	276	284	293
Dividend ($ million)	262	463	481	385	285	185	85	-	-	-
Regulatory Account ($ million)	181	339	672	940	1,010	1,088	1,075	914	560	-
Total Debt	16,656	17,409	18,288	19,217	19,686	19,642	19,309	18,751	17,876	17,352
Debt to Equity Ratio	80:20	80:20	80:20	80:20	79:21	77:23	75:25	72:28	69:31	66:34
Heritage Deferral Account ($ million)	12	9	54	30	19	12	8	4	-	-
Non-Heritage Deferral Account ($ million)	383	274	169	93	60	37	25	13	-	-

However, in 2016, as shown in Table 5-2, the actual combined balance in the HDA and the NHDA was $1,167 million – a difference of $884 million compared to the 2013 forecast.[403]

Our observations outlined in the Commission's August 25, 2017 issuance of the Key Findings relating to BC Hydro's Load Forecast note that BC Hydro's Non-Heritage Deferral Account (NHDA) captures many variances, and as illustrated in the table below, with the largest impact attributed to the domestic load forecast variances:

[400] Ibid., BCUC IR 124.1.
[401] Exhibit B-1-1, p.7-6.
[402] Exhibit B-10, AMPC IR 4.1.
[403] ($917 million + $250 million) - ($9 million + $274 million)

Table 5-4: Non Heritage Deferral Account[404]

Non-Heritage Deferral Account Annual Summary																		
Year	Reported Opening Balance	Cost of Energy	Commodity Risk	Notional Water Rental	FX Gains & Losses on Powerex Trade	Domestic Revenue Variance (2009)	ABSU Founding Partner Benefits	Deferred Operating Costs in NHDA	RRA Adjustments	PTP and NITS Variance	Capital Lease Adjustment	Burrard Costs	Other	Total Changes	Rounding	Amortization	Interest	Ending Balance
F2005	0.0	154.5	-5.3	-10.7	-10.6									127.9			3.0	130.9
F2006	130.9	44.7	19.8	0.2	-3.9		-0.6	7.3	-2.9					64.6	0.1		9.0	204.6
F2007	204.6	35.5	3.3	-4.9	4.9		-0.6	-2.7						35.5		-45.3	14.0	208.8
F2008	208.8	-54.3	-3.0	2.9	-18.6		-0.5		-33.7					-107.2	0.1	-58.9	8.8	51.6
F2009	51.6	-51.5	9.7	-0.7	9.7	20.4	-0.5		43.2					30.3		-14.9	7.4	74.4
F2010	74.4	-22.8	-0.4	-9.3	-4.5	82.5	-0.6							44.9		-6.6	6.8	119.5
F2011	119.5	-44.5	-12.1	-1.6	-4.0	42.4	-0.2		262.9	16.0				258.9		-23.5	7.3	362.2
F2012	362.2	-147.0	12.9	18.9	2.4	62.8	0.6	11.2	65.9	0.3				28.0	-0.3	-39.8	16.9	367.0
F2013	367.0	-166.6		5.1	-3.9	176.1	0.4		103.2	-12.2			62.2	164.3	-0.1	-84.0	20.3	467.5
F2014	467.5	-195.5	15.2	-14.9		137.7		-0.9	49.8	5.3				-3.3	0.0	-120.3	17.7	361.6
F2015	361.6	50.7	-4.8	-5.1		207.3				8.8	-22.8	4.1		238.2	0.1	-90.6	14.8	524.1
F2016	524.1	235.4	-0.5	1.9		268.9				-0.7	-31.0	9.0		483.0	-0.1	-117.7	27.5	916.8
Cummulative Total		-161.4	34.8	-18.2	-28.5	998.1	-2.0	14.9	488.4	17.5	-53.8	13.1	62.2	1,365.1	-0.2	-601.6	153.5	

While all of the other balances in the NHDA have been both positive and negative, thereby capturing the intent and purpose behind a variance account treatment, the exception is the domestic revenue variance, which has held a consistent and growing negative variance. Because BC Hydro's actual load has been less than its forecast since F2009, there have been significant additions to the NHDA every year. The Panel observes that the annual variance related to domestic revenues has steadily increased from $20 million in F2009 to $269 million in F2016 for total additions of $998 million in 8 years. On average the variance has been $125 million per year over the fiscal 2009 to fiscal 2016 period and the average annual addition has been $171 million over the last five-year (i.e., fiscal 2012 to fiscal 2016) period.[405]

These additions underline the Panel's concerns about the increasing impact on the NHDA of the load variance and surplus energy purchases. In our findings on the load forecast, "[t]he Panel observes that the annual variance related to domestic revenues has steadily increased from $20 million in F2009 to $269 million in F2016 for total additions of $998 million in 8 years."[406] These additions arose not only because of a variance between forecast and actual domestic demand, but also from purchases of energy from long term contractual obligations. If this oversupply can't be managed there will continue to be upward pressure on rates because of the need to amortize the balance in this account to comply with the Commission's direction to clear the balances of regulatory accounts.

This, combined with the risk of reduced demand because of upward trends in rates remains a concern. We reiterate the Commission's findings in the Site C Report:

> The Panel finds there will be considerable upward pressure on rates for the remainder of the 2013 10 Year Rates Plan and beyond fiscal 2024. The Panel finds the risk associated with this upward pressure on rates is especially concerning given the submissions related to potential "demand destruction" that could result from the impact of real rate increases on already vulnerable industrial customers and the likelihood that even nominal rate increases will increase energy poverty among BC's low income households.
>
> BC Hydro presents the rate impact before DSM of a 1.0 percent change in real rates (Table 6), illustrating a 67 GWh and 464 GWh change in load for F2026 and F2036, respectively. The issue for the Panel is whether it is appropriate to accept BC Hydro's assumption of zero real rate

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404 Exhibit B-9, BCUC IR 126.1.

405 Exhibit B-9, BCUC IR 124.7

406 August 25, 2017 Key Findings – Load Forecast, p. 10.

increase post 2024 for the purpose of making our assessment on the load forecast. In the Preliminary Report, the Panel discussed that future rates could be impacted by changes to government policy with respect to proceeding with the elimination of the Tier 3 water rates, changes to the calculation of the ROE, reducing the dividend, and other policies in the 2013 10 Year Rates Plan and beyond. The Panel also recognized that achievement of the targets in the 2013 10 Year Rates Plan are subject to risk with respect to policy changes, weather, industrial load, LNG load, interest rates, energy markets and Site C budget uncertainties, among other things.

In the Panel's view, the fact that BC Hydro's residential rates have not increased on a real basis over the very long term does not provide adequate support for the reasonableness of the assumption of no real increases going forward. Future rate increases are more likely to be impacted by more recent experience and expected changes going forward rather than by the long-term history of increases in real rates. The Panel agrees with Hendriks et al. that there has been a shift in BC Hydro's costs in the last 10 years, partially as a result of the 2007 Energy Plan which increased rates due to the policy to decarbonize electricity generation (e.g. IPPs and decommissioning of Burrard Thermal).

The Panel is concerned that the size of increases in revenue requirements in the last 10 years (before the imposition of mandatory rate caps and rate smoothing regulatory accounts), the requirement for BC Hydro to clear out regulatory accounts periodically, the considerable future capital expenditures that will be needed to maintain heritage assets, and the costs to complete Site C (including interest carrying costs and the risk of any further cost overruns) can reasonably be expected to have upward pressure on real rates. With respect to the rate impacts to bring Site C into rates, the Panel is not convinced that even on a smoothed basis it is reasonable to assume no real rate increases. In addition to these considerable pressures on rates, the ability to meet the 2013 10 Year Rates Plan and keep real rates flat beyond the 10 Year Rates Plan will be impacted if actual demand is less than the 2016 mid forecast.

The Panel acknowledges BC Hydro's submission that in the past it has worked with government to take actions to keep rates low and the Government's recent announcement that a comprehensive review of BC Hydro will be undertaken. Considering information presented by BC Hydro in its F2017–F2019 RRA related to its past effort to manage costs resulting from the 2011 Government Review, the 2013 10 Year Rates Plan, and subsequent actions including the deferral of some capital project as part of its effort, the Panel considers there is risk related to BC Hydro's ability to keep electricity rates low and predictable over the period of the Current Load Forecast and the 70-year life of the Site C project.

The Panel also notes the submissions from participants who raise concerns that future rate increases could also be impacted by real interest rate changes and the impact of any changes in credit rating that could result from BC Hydro's higher debt load, its high level of regulatory account balances and off-balance sheet IPP commitments. Both the Provincial Government and BC Hydro's credit rating could potentially be impacted by these factors and by the Auditor General's report qualification. [407]

[407] BCUC Site C Final Report, pp. 81–82.

Forecast recoveries of the COE Variance Accounts and the RSRA

Forecast recoveries of the COE Variance Accounts are dependent on the Deferral Account Rate Rider (DARR) mechanism set out in section 10(3) of Direction No. 7, in which the portion of the forecast revenue from the DARR to be applied to the COE Variance Accounts in a given year will be less than 100 percent if the net balance in the COE Variance Accounts at the end of the immediately preceding fiscal year is less than $500 million.

According to Table 2 above, for the years F2020 to F2024, BC Hydro is forecasting the balance in the COE Variance Accounts to be less than $500 million therefore only a portion of the DARR will be applied against the COE Variance Accounts with the remainder to be available to reduce the overall revenue requirements. In particular, BC Hydro forecast $809 million of DARR revenue in the last four years of the 2013 10 Year Rates Plan available to assist in achieving the target annual rate increases of 2.6 percent.[408] However, although BC Hydro forecasts a reduction of this account to less than $500 million over the test period and remaining years of the 2013 10 Year Rates Plan, the balance is highly dependent on BC Hydro's load forecasting abilities. Given the accuracy of BC Hydro's forecast since 2009, the Panel is not persuaded that in the remaining years of the 10 year plan, the actual balance of this account will track the forecast balance.

The Panel finds that a key component of keeping the rate increase in the latter part of the 10 Year Plan at 2.6 percent and clearing the $1.6 billion of the RSDA is the availability of the $809 million dollars from the DARR in F2021 to F2024 to reduce the general revenue requirement. Therefore, if the actual additions to the COE Variance Account are greater than forecast between F2017 and F2024 resulting in an overall balance greater than $500 million in F2021 to F2024,[409] as has been the case since F2010, the full amount of the DARR will be used towards reducing the COE Variance Accounts in accordance with Direction No. 7 and the $809 million will not be available for reducing the general revenue requirement and indirectly recovering the forecast RSRA balance in order to meet the 10 Year Rate Plan.

This would be further exacerbated if the Amended Application for a rate freeze in F2019 is approved, as that will, all else equal, increase the balance of the RSRA by an additional $140 million.

Commission determination on rate increases for F2017, F2018 and F2019

The Panel approves the following rates increases as permanent and as applied for: 4 percent for F2017 and 3.5 percent for F2018. These increases are significant – they outpace inflation, and therefore represent real rate increases. Further, they come on top of real rate increases for F2012 through F2016. However, as these increases do not fully recover BC Hydro's approved total forecast revenue requirement, the Panel is not persuaded that any lower increase is warranted.

BC Hydro's Amended Application, reducing the requested F2019 rate increase from 3.0 percent, the maximum allowed under Direction No. 7, to 0 percent, has the effect of, all else equal, ensuring that achieving the 2013 10 Year Rates Plan is made more difficult and could require future rate increases in excess of those contemplated in the remaining years of the 2013 10 Year Rates Plan.

[408] Exhibit B-9, BCUC IR 124.5; Exhibit B-14, BCUC IR 276.3; Exhibit B-15, BCOAPO IR 88.1; Exhibit B-15, McCandless, IR 3.3
[409] Ibid., BCUC IR 124.5, 124.8.

BC Hydro states that "the expected recovery period for the Rate Smoothing Regulatory Account has not changed..." there is no "revenue shortfall remaining at the end of the ten-year rate plan period." It further states that "If the lower revenue caused by a zero per cent rate increase in fiscal 2019 results in higher annual rate increases in the fiscal 2020 to fiscal 2024 period (i.e., higher than 2.6 per cent as forecast during the proceeding, and as forecast in the 2013 10 Year Rates Plan), and there are no changes in BC Hydro's revenue requirements resulting from the comprehensive review of BC Hydro or the refreshed plan for rates that will be developed, then there would be no revenue shortfall in the fiscal 2020 to fiscal 2024 period." [410]

BC Hydro argues that justification to approve the rate freeze can be found in the following:

1. The Minister's Mandate Letter as a clear expression of government policy and the Commission is free to give significant weight to Government policy, as the Commission has done in the past.
2. The rate freeze can be implemented while respecting other regulatory principles.

With regard to the first justification described above, the Panel generally agrees with the analysis of Fortis BC and outlined in its Final Argument dated January 15, 2018. In particular, we agree that "general policy statements not captured in a statute, regulation or s. 3(1) direction are not binding". As FortisBC points out, the Commission has previously considered this issue and determined that:

> the [Utilities Commission] Act accords general policy statements of government no more weight than any other evidence brought before it, unless the policy statement is given the weight of a direction or special direction under Section 3(1) or 3.1 of the [Utilities Commission] Act.

The Panel now considers the rate freeze in the context of regulatory principles, as outlined in Item (2) above.

BC Hydro has requested rates set on a cost of service basis and the Panel has evaluated this application on that basis. This requires the Panel to ensure that all approved forecast costs be included in rates unless there is either a regulatory justification to defer some costs for collection in a future period or a statutory requirement to do otherwise.

Regulatory principles underlying rate making are widely accepted as being expressed in the "Bonbright Principles." The Panel looks to these principles for guidance in this matter:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety
2. Revenue stability and predictability, with a minimum of unexpected changes that are seriously adverse to utility companies
3. Stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to utility customers and that are intended to provide historical continuity
4. Static efficiency, i.e., discouraging wasteful use of electricity in the aggregate as well as by time of use
5. Reflect all present and future private and social costs in the provision of electricity (i.e., the internalization of all externalities)
6. Fairness in the allocation of costs among customers so that equals are treated equally

[410] Exhibit B-10, BCOAPO IR 4.147.1.

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (free of subsidies)
8. Dynamic efficiency in promoting innovation and responding to changing demand-supply patterns
9. Simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application
10. Freedom from controversies as to proper interpretation[411]

One possible approach to freezing the rate for F2019 is to reduce the revenue requirement. As previously discussed, the only area available to the Panel for such a reduction is in BC Hydro's O&M and capital additions expenditures. However, BC Hydro argues that it has made significant reductions to these expenditures and needs the amount requested in order to provide safe and reliable service. Therefore it may be possible to arbitrarily reduce some of BC Hydro's expenditures, but potentially at the expense of safety or reliability. The first principle outlined above suggests that rates should not result in a "socially undesirable level of product quality and safety". There is no evidence before the Panel that a reduction in the level of quality and safety that would result from a revenue requirement reduction, would not be "socially desirable."

The second principle outlined above is Revenue Stability and Predictability. By not collecting revenues – i.e. by deferring revenue collection into the future – may have an impact on the credit worthiness of a utility. Continuing to defer revenue collection may ultimately impact the sustainability of a utility.

The third principle on the list of Bonbright principles suggests that a rate freeze may be warranted in the face of seriously adverse sudden changes – or "rate shock." Rate shock is an unexpected change (typically an increase) in rates, typically caused by a one-time unexpected event, that isn't expected to continue in the future. A ten percent increase is often cited as the threshold. However, while many regulatory bodies do consider 10% to be the threshold, there isn't a universally accepted threshold beyond which rate shock occurs. In some cases it may be instructive to consider more than one year of rate increases. For example a rate increase of 9 percent for each of three consecutive years may have a greater impact on customers than an 11 percent increase in year one and none in years two and three.

As we have previously discussed, the 3 percent rate increase in F2019 comes on top of a number of previous rate increases greater than inflation:

[411] Principles of Public Utility Rates by James C. Bonbright, pp. 383–384.

Table 5-5: Real Rate Increase

Year	Rate Increase	CPI[412]	Real Rate Increase
F2012	8.0%[413]	1.1%	6.9%
F2013	3.91%[414]	-0.1%	4.01%
F2014	1.44%[415]	1.0%	0.44%
F2015	9.0%	1.1%	7.9%
F2016	6.0%	1.8%	4.2%
F2017	4.0%	2.1%[416]	1.9%
F2018	3.5%	2.1%	1.4%
F2019[417]	3.0%	2.0%	1.0%
F2020	2.6%	2.0%	0.6%
F2021	2.6%	2.0%	0.6%
2022	2.6%[418]	2.0%[419]	0.6%

These increases taken together may be "seriously adverse" to some customers and therefore, in the Panel's view, be considered rate shock. However, we note the increases have reduced considerably compared to F2015 and F2016. In particular, the originally applied for rate increase of 3 percent for 2019 represents a real rate increase of approximately 1 percent.

A further consideration is that in the case of rate shock, the additional revenue requirement must be deferred and collected over future periods. Depending on the period over which it is amortized, this could give rise to issues of generational inequity. As with rate shock, there is no hard and fast rule as to what is considered intergenerational inequity, but generally more than a few years is accepted by many regulatory bodies.

BC Hydro argues that "the potential for any such impacts must be weighed against the immediate benefits to customers in fiscal 2019 due to the rate freeze and the potential for offsetting cost savings in the future. The Government has made it clear that a comprehensive review of BC Hydro will be completed in conjunction with the development of a refreshed plan for rates, with the results being reflected in rates starting in fiscal 2020."[420] While the Panel is optimistic that the review of BC Hydro will find sufficient savings to offset the cost of the rate

412 CPI shown is for the calendar year, not BC Hydro's Fiscal Year.
413 Order G-77-12A.
414 Ibid.
415 Ibid.; Order G-48-14.
416 2012 – 2017: Statistics Canada, CANSIM Table 326-0021: http://www5.statcan.gc.ca/cansim/a26?id=3260021
417 As originally applied for.
418 Exhibit B-1-1, p. 1-6.
419 2018–2022: http://www.bcbudget.gov.bc.ca/2017_Sept_Update/bfp/2017_Sept_Update_Budget_and_Fiscal_Plan.pdf page 78.
420 BC Hydro January 19, 2018 Reply Argument, pp. 9–10.

freeze, we find it premature to "spend" those savings before they have even been identified and we are not persuaded that this is sufficient justification to approve the rate freeze.

Further, in order to be an effective mitigation to rate shock, deferring the collection of a portion of a revenue requirement to a future period must not impose rate shock in that future period. The ten year rate plan already forecasts increases slightly higher than inflation (2.6 percent) for 2020 through 2022 in the original Application and 3.8 percent in the Amended Application, as shown in the table below.

Table 5-6: Updated Rate Impact As a Result of F2019 Rate Freeze[421]

F19 Rate Freeze followed by 3.8% rate increases for F20-F24	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024
Rate Increase (%)	9.0	6.0	4.0	3.5	0.0	3.8	3.8	3.8	3.8	3.8

We have previously discussed concerns with variances in the load forecast and cost of energy and the amount of excess energy that is purchased at relatively high rates. It seems unlikely to the Panel that the actual revenue requirements in the next three years will be less than the 2.6% forecast in the ten year rates plan, and could be more. This means that in order to make the ten year rates plan, reducing the originally proposed F2019 increase from 3.0% to 0% will result in rate increases in the following three years that could exceed 3 percent.

The Panel acknowledges the issue of affordability caused by real rate increases. We further agree that freezing the rate for one year increase the affordability of electricity for that year, thereby reducing the hardship that may otherwise be faced by some customers. However, under the current legislative and regulatory framework, the Panel is unable to consider the economic circumstances of individual ratepayers.[422] Simply stated, a utility is entitled to recovery of its prudently incurred expenditures and utility owners are entitled to a fair return on its invested capital. These costs should be reflected in rates to customers who benefit in that period and must not be deferred to future periods in the absence of a statutory or regulatory justification. We note that if a utility owner is willing to forego some or all of their return on investment, rates could potentially be reduced accordingly.

The Panel also acknowledges that the Government is 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, lowering the calculation of BC Hydro's return on equity, and reducing BC Hydro's dividend payment.[423]

For the reasons cited above, the Panel finds that there is not sufficient regulatory justification for approving real rate decreases – unless cost reductions justify those decreases, and that is not the case here. Further the Panel is not persuaded that there is sufficient regulatory justification for not approving the rate increase originally applied for F2019. **Accordingly the Panel approves a rate increase of 3.0 percent, the rate cap established in Direction No. 7, for F2019 and the OATT as proposed by BC Hydro in its Application and as corrected in Errata No. 1 for F2019.**

[421] Exhibit B-25, BCOAPO 4.147.1.
[422] BC Hydro 2015 Rate Design Decision, pp. iv, 59, 67.
[423] Exhibit B-10, CEABC IR 1.3.4.

BC Hydro is directed to re-calculate its revenue requirements, including its rate of return, based on the Panel's determinations elsewhere in this decision, in a compliance filing within 60 days of this decision. BC Hydro is directed to include in its compliance filing, a revised Appendix A to the Application and updated rate schedules, reflecting the Commission's Order and Decision and BC Hydro's commitments articulated in Part Thirteen of its Final Submission.

The Panel approves the transfer of the difference between the forecast revenue requirement and the forecast amount collected in rates to be transferred to the RSRA for each of the three years in the test period.

5.2 Future revenue requirements

As previously discussed, the Panel is concerned about the ability of BC Hydro to achieve the ten year rates forecast, in the light of rising O&M costs, lower than forecast load, increasing energy costs, and increasing deferral account balances. We acknowledge BC Hydro's cost cutting measures and also the upcoming comprehensive government review of BC Hydro's expenditures and we are hopeful that further efficiencies can be found.

Our concern lies in the apparent decoupling of revenues and expenditures within the test period. Expenditures have risen faster than revenues. A company with expenditures that exceed its revenues is not sustainable. Accordingly we are of the view that a rate setting mechanism that could help BC Hydro to accomplish its cost control objectives is of value.

Performance Based Rate (PBR) setting mechanisms are implemented successfully in many jurisdictions, particularly in Canada, including BC. PBR provides incentives for utilities to improve productivity and create efficiencies to allow for rates to be more effectively managed, while maintaining service quality. Section 60(1)(b.1) of the UCA provides the necessary legislative framework for a PBR plan. FortisBC Energy Inc., a natural gas utility in BC of comparable size to BC Hydro, is currently on a PBR plan which has a term spanning from 2014 through 2019, and was previously on a PBR plan from 2004 through 2009. FortisBC Inc., a vertically integrated electric utility, with generation, transmission and distribution assets, is also currently on a PBR plan with a term spanning from 2014 through 2019. FortisBC Inc. has had two previous PBR plans in the past (1996-2004 and 2007-2011).

In the proceeding BC Hydro was asked if it has considered applying for a Performance Based Plan in future test periods, in particular with a mechanism where cost caps are implemented to match rate caps, and the utility manages it owns operating costs within the cost caps.

BC Hydro is not currently considering applying for a performance based ratemaking (PBR) plan and has "not given the option of a PBR plan sufficient consideration to provide a fully informed opinion on the pros and cons to customers and to BC Hydro." Notwithstanding, BC Hydro states that there are "some potential generic pros and cons of PBR. For example, a PBR mechanism can help to facilitate longer-term planning and budgeting where short-term investments may be required to produce longer-term benefits. Also under PBR, the utility/shareholder and customers can share benefits if actual costs are less than the target amounts, and there is corresponding risk mitigation for the utility."[424]

BC Hydro lists the downsides as: "PBR plans are complex and may take multiple iterations to perfect over time (setting productivity factors etc.). There may also be an extended period between full revenue requirements applications, which may be of concern to some stakeholders. As well, significant components of a utility's costs may be non-controllable and not suited to being subject to a PBR formula, such as cost of energy, which form a significant portion of BC Hydro's revenue requirements. It can also be difficult to accommodate "lumpy" capital within a formula, and large capital investment plans such as BC Hydro's may therefore not be suitable for a PBR. Other issues include potentially increased reporting requirements during the performance term, and stakeholder acceptance of the PBR structure, term and formulas, etc."[425]

In our view in many cases, the benefits can outweigh the costs. Direction No. 7, section 5(c), recognizes the benefits of a PBR plan, with regard to the cost of energy, stating "In setting the authority's rates, the commission may employ any mechanism, formula or other method authorized by section 60 (1) (b.1) of the Act." We recommend that BC Hydro consider a PBR plan starting in F2020. Typically, the first year of a PBR plan is a "base year" and the revenue requirement is developed on a cost of service basis. Revenue requirements for subsequent years are then calculated from the base year, using productivity factor and CPI, among other things. An earnings sharing mechanism can also be applied to create an incentive for efficiencies, while key performance indicators may be established to ensure that the utility maintains suitable its infrastructure and service to ensure safe, reliable, service.

Accordingly, the Panel directs BC Hydro to file, by June 20, 2018, a report that addresses the following:

- **A discussion of the types of PBR plans that may be suitable for BC Hydro (i.e. Revenue Cap, Price Cap, hybrid).**
- **A discussion of potential earnings sharing mechanisms that may be suitable for BC Hydro.**
- **Implementation timetable, in particular a timetable that considers the F2020 RRA as the base year followed by a period of years in which rate/revenue requirements are set by the PBR formula. The Implementation timetable should also include a proposed schedule of consultation with representatives of key customer groups and Commission staff.**
- **How capital spending could be managed as part of the PBR program.**
- **The length of PBR term that may be appropriate.**
- **Annual Review process and/or other monitoring processes during the PBR term**
- **The appropriateness of off-ramps.**
- **A list of potential key performance indicators to assist BC Hydro and the Commission to evaluate progress during the PBR term.**

The report should provide a high level discussion of the issues outlined above and BC Hydro's possible PBR approach.

[424] Exhibit B-25, BCUC IR 4.5.2.
[425] Exhibit B-25, BCUC IR 4.5.2.

6.0 Summary of directives

This summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the decision, the wording in the decision shall prevail.

<table>
<tr><th></th><th>Directive</th><th>Page No.</th></tr>
<tr><td>1.</td><td>To better understand the rate impact resulting from energy surpluses, portfolio management of the Heritage Assets, and the variances discussed above, The Panel directs BC Hydro, in a compliance filing, to provide to the Commission with the following:
i. A reconciliation of the calculation in Exhibit B-1-1 Appendix A, Schedule 4 with the forecast Heritage Energy in Table 3-8 of the 2013 IRP. A detailed schedule, by year, of the actual Heritage Energy delivered to BC Hydro distribution in each of the last 10 years;
ii. A breakdown of the Net Purchases (sales) from Powerex line item within the Heritage Energy section of Exhibit B-1-1, Appendix A, Schedule 4 into gross volumes;
iii. A description of the items included in each category contained in the Heritage Energy section of Exhibit B-1-1, Appendix A, Schedule 4, particularly including a description of the items included in “Surplus Sales,” as well as gross volumes from Powerex, per ii) above;
iv. A discussion of whether actual energy delivered for distribution by Heritage Assets has been reduced below availability in any way due to energy supplied by IPP energy;
v. A thorough explanation of the amount of Heritage Energy that is deliverable and expected to be delivered in each of the next 5 years and, if appropriate, a description of how this varies from actual historical deliveries;
vi. A thorough discussion of whether the generating abilities of any Heritage Assets have been impaired or reduced in any way; and
vii. A recommendation regarding whether the definition of Heritage Energy in the Heritage Contract should be revised pursuant to Section 8 of the Heritage Contract.</td><td>25</td></tr>
<tr><td>2.</td><td>Therefore we direct BC Hydro to explain in its compliance filing the accounting treatment of surplus energy costs and recoveries.</td><td>25</td></tr>
<tr><td>3.</td><td>pursuant to section 45(5) of the UCA, if BC Hydro intends to pursue any of these extensions, the Panel directs BC Hydro to file CPCN applications for the following projects:
a. Metro North Transmission
b. West Kelowna Transmission/Westbank Substation Upgrade
c. Northwest Substation Upgrade
d. Peace Region to Kelly Lake 500kV Transmission Reinforcement
e. Mainwaring Substation Upgrade</td><td>39</td></tr>
</table>

	Directive	Page No.
4.	The Panel denies CEC's requested changes to the refresh rates for laptops.	47
5.	The Panel denies CEC's request to reduce BC Hydro's technology capital budget by the costs of the Graphic Design Tool project.	47
6.	The Panel denies CEABC's request that BC Hydro change its plans for the Fort St. John to Taylor Electric Supply project, the Peace Region Electric Supply project, the Bridge River system projects, and the Campbell River system projects.	47
7.	The Panel takes no exception to the treatment of the regulatory accounts for which BC Hydro is not requesting any changes to the scope, recovery mechanism or application of interest. Subject to the determinations on issues addressed in sections 3.4.1 to 3.4.4, the Panel approves the remaining deferral and regulatory account requests contained in BC Hydro's Table 7-9 of the Application.	57
8.	The Panel approves the actual fiscal 2016 closing balance in the First Nations Costs Regulatory Account that is related to the difference between the specific amortization amounts directed by Order G-48-14, and the calculation of amortization based on actual transfers into the First Nations Costs Regulatory Account in F2014, F2015 and F2016 be amortized in fiscal 2017	58
9.	The Panel approves the following: i. Effective starting in F2017 and on an ongoing basis, the actual lump sum settlement payments and annual settlement payments be deferred to the First Nations Costs Regulatory Account each year. ii. Effective starting in F2017 and on an ongoing basis, the forecast lump sum settlement payments be amortized over ten years, starting in the year of payment, and forecast annual settlement payments be amortized in the year paid from the First Nations Costs Regulatory Account. The Panel approves, effective starting in fiscal 2017, and on an ongoing basis, actual negotiations costs will be deferred to this account each year, and actual negotiations costs will be recovered from this account each year.	59–60
10.	The Panel approves the following requests: i. Effective starting in F2017, and on an ongoing basis, the forecast interest charged will be amortized from First Nations Costs Regulatory Account each year. ii. On an ongoing basis, the forecast account balance in the First Nations Costs Regulatory Account at the end of a test period related to the difference between the amortization of the forecast annual and lump sum settlement payments and the calculation of amortization based on the actual annual and lump sum settlement payments during that test period will be recovered over the subsequent test period. iii. On an ongoing basis, the forecast account balance in the First Nations Costs Regulatory Account at the end of a test period related to the difference between the forecast interest recovered and the actual interest charged to	60

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	the First Nations Costs Regulatory Account during that test period will be recovered over the subsequent test period. iv. The actual F2016 closing balance in the First Nations Costs Regulatory Account that is related to the lump sum settlement payment made in F2016 will be amortized over nine years, beginning in F2017. v. The actual F2016 closing balance in the First Nations Costs Regulatory Account that is related to settlement payments and negotiation costs incurred prior to F2015 will be amortized over eight years beginning in F2017. vi. Interest be applied to the balances in the First Nations Costs Regulatory Account, consistent with the application of interest to other variance accounts, based on BC Hydro's current WACD.	
11.	For the F2017 to F2019 test period only, the Panel directs the establishment of a new regulatory account, the Dismantling Cost Regulatory Account (DCRA), to defer, on an annual basis, any variances between planned and actual dismantling costs during the F2017 – F2019 test period subsequent to the full draw down of the Future Removal and Site Restoration Regulatory Account.	62
12.	The Panel approves BC Hydro's proposal to recover the forecast account balance at the end of the test period over the next test period, and the application of interest, consistent with the application of interest to other variance accounts, based on BC Hydro's current WACD. BC Hydro's proposal to change the scope of the regulatory account to defer the variances between planned and actual dismantling costs and BC Hydro's proposal to rename the Future Removal and Site Restoration Regulatory Account to the DCRA are denied. Given that the balance of the existing account has been drawn down to zero in the first quarter of F2017, the Panel further directs BC Hydro to close out this regulatory account in F2017.	63
13.	The Panel approves BC Hydro's proposal to continue to defer to the Asbestos Remediation Regulatory Account the variances between actual and forecast asbestos remediation costs pursuant to Direction No. 7. Effective starting in fiscal 2017, and on an ongoing basis, actual asbestos remediation costs at BC Hydro facilities will be deferred to this account each year, and forecast asbestos remediation costs will be amortized from this account each year.	64
14.	BC Hydro's request to expand the regulatory account to capture PCB compliance costs is approved. Accordingly, BC Hydro's proposal to change the name of this account from Asbestos Remediation Regulatory Account to the Remediation Regulatory Account is also approved. Effective starting in fiscal 2017, and on an ongoing basis, actual expenditures related to compliance with polychlorinated biphenyl regulations will be deferred to this account each year, and forecast expenditures related to compliance with polychlorinated biphenyl regulations will be	64–65

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	amortized from this account each year.	
15.	The Panel also approves the following requests related to BC Hydro's Remediation Regulatory Account: i. The closing F2016 balance in the Regulatory Account will be recovered over the F2017 to F2019 test period; ii. Interest will continue to be applied to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current WACD; iii. Effective starting in F2017, and on an ongoing basis, the forecast interest charged to the Remediation Regulatory Account each year will be recovered in each year; and iv. On an ongoing basis, the forecast Remediation Regulatory Account balance at the end of a test period will be recovered over the next test period.	65
16.	The Panel approves the following BC Hydro requests regarding the recovery mechanism for the Non-Current Pension Costs Regulatory Account: 1. The portion of the forecast account balance at the start of a test period related to the variance transferred to the account during the previous test period will be amortized over a period of time based on the EARSL of the active plan members at the start of the test period. 2. The portion of the actual or forecast account balance at the start of the test period related to variances between its actual and forecast non-current pension costs for the F2015 to F2016 test period will be amortized over the EARSL of the active plan members at the beginning of the F2017 to F2019 test period. 3. The portion of the actual or forecast account balance at the start of the test period related to variances between its actual and forecast non-current pension costs for the F2011 to F2014 test period continue to be amortized over the EARSL of the active plan members at the beginning of the fiscal 2015 to F2016 test period.	70
17.	The Panel denies BC Hydro's proposal to include in the Non-Current Pension Costs Regulatory Account the deferral of the annual variance between the forecast costs and actual costs related to the operating cost portion of post-employment benefit current pension costs. The request to change the name of the Non-Current Pension Costs Regulatory Account, effective fiscal 2017, and on an ongoing basis, to the Pension Costs Regulatory is denied. The Panel directs the following: i. The establishment of a new regulatory account, PEB Current Pension Costs Regulatory Account, to defer the annual variance between the forecast costs and actual costs related to the operating cost portion of PEB Current Pension Costs, on an ongoing basis; ii. The transfer of the F2016 variance of $17.2 million approved by Order G-	70–71

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	148-15 from the Non-Current Pension Costs Regulatory Account to the PEB Current Pension Costs Regulatory Account, with this amount to be amortized over the F2017 – F2019 test period; and iii. The portion of the forecast account balance in the PEB Current Pension Costs Regulatory Account at the start of a test period related to the variance transferred to the account during the previous test period is to be amortized over the subsequent test period.	
18.	The Panel denies BC Hydro's proposal to use an average of actual past discount rates used in the calculation of actual current service costs in the preceding five fiscal years for forecasting purposes, and directs BC Hydro to continue with its previous method of using the discount rate in effect at the time the forecast was prepared.	71
19.	Since the F2017 forecasted actuarial gain included in the Application would not be recognized using the previous forecast method, the Panel denies BC Hydro's proposal to amortize this gain over the EARSL of the active plan members at the beginning of fiscal 2018.	72
20.	The Commission Panel accepts BC Hydro's DSM expenditure schedule contained in the Application.	75
21.	The Panel recommends BC Hydro consider more targeted DSM programs directed at residential customers in the next DSM application.	81
22.	The Panel directs BC Hydro, in its next DSM application, to review whether BC Hydro's approach to attributing all of the savings are occurring from the implementation of codes and standards to its codes and standards program is consistent with industry practice.	83
23.	the Panel directs BC Hydro to include a line item in BC Hydro's Annual Report on DSM Activities to reflect the NIA activities that are tracked separately. The Panel further directs BC Hydro to include in its next DSM application: • an estimate of the differences in TRC, mTRC and UCT results of BC Hydro's DSM programs available to customers in the NIAs compared to the integrated areas; and • an update of whether (and if so how) BC Hydro has addressed the DSM concerns raised above by NIARG and Zone II regarding the NIAs.	84
24.	The proposed depreciation rates for BC Hydro's Burrard synchronous condense facility, as set out in Table 8-1 of the Application, are approved.	86
25.	The Panel approves the OATT as proposed by BC Hydro in its Application and as corrected in Errata No. 1 for F2017 and F2018. The request in its Amended Application regarding the F2019 OATT rates is dealt with in section 5.1 of the Decision. The Panel also approves the proposed method to apply a one-time charge to Transmission Customers for the difference between the proposed and the interim F2017 OATT.	92

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26.	The Panel approves the following rates increases as permanent and as applied for: 4 percent for F2017 and 3.5 percent for F2018.	105
27.	Accordingly the Panel approves a rate increase of 3.0 percent, the rate cap established in Direction No. 7, for F2019 and the OATT as proposed by BC Hydro in its Application and as corrected in Errata No. 1 for F2019. BC Hydro is directed to re-calculate its revenue requirements, including its rate of return, based on the Panel's determinations elsewhere in this decision, in a compliance filing within 60 days of this decision. BC Hydro is directed to include in its compliance filing, a revised Appendix A to the Application and updated rate schedules, reflecting the Commission's Order and Decision and BC Hydro's commitments articulated in Part Thirteen of its Final Submission. The Panel approves the transfer of the difference between the forecast revenue requirement and the forecast amount collected in rates to be transferred to the RSRA for each of the three years in the test period.	109–110
28.	Accordingly, the Panel directs BC Hydro to file, by June 20, 2018, a report that addresses the following: • A discussion of the types of PBR plans that may be suitable for BC Hydro (i.e. Revenue Cap, Price Cap, hybrid). • A discussion of potential earnings sharing mechanisms that may be suitable for BC Hydro. • Implementation timetable, in particular a timetable that considers the F2020 RRA as the base year followed by a period of years in which rate/revenue requirements are set by the PBR formula. The Implementation timetable should also include a proposed schedule of consultation with representatives of key customer groups and Commission staff. • How capital spending could be managed as part of the PBR program. • The length of PBR term that may be appropriate. • Annual Review process and/or other monitoring processes during the PBR term • The appropriateness of off-ramps. • A list of potential key performance indicators to assist BC Hydro and the Commission to evaluate progress during the PBR term. The report should provide a high level discussion of the issues outlined above and BC Hydro's possible PBR approach.	111

Dated at the City of Vancouver, in the Province of British Columbia, this *1st* day of March 2018.

Original signed by:

David M. Morton
Panel Chair / Commissioner

Original signed by:

Karen A. Keilty
Commissioner

Original signed by:

Douglas J. Enns
Commissioner

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ORDER NUMBER
G-47-18

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
F2017 to F2019 Revenue Requirements Application

BEFORE:
D. M. Morton, Commissioner / Panel Chair
D. J. Enns, Commissioner
K. A. Keilty, Commissioner

on March 1, 2018

ORDER

WHEREAS:

A. On July 28, 2016, the British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2017 to Fiscal 2019 Revenue Requirements Application with the British Columbia Utilities Commission (Commission) requesting, among other things, final approval to increase rates by an average of 4.0 percent effective April 1, 2016, 3.5 percent effective April 1, 2017 and 3.0 percent effective April 1, 2018 (Application);

B. On March 6, 2014, B.C. Reg. 28/2014 enacted Direction No. 7 (Direction No. 7) to the Commission pursuant to section 3 of the *Utilities Commission Act* (UCA). Direction No. 7, among other things, requires the Commission to approve average rate increases of no more than 4.0 percent, 3.5 percent and 3.0 percent effective April 1, 2016, 2017 and 2018, respectively. Further, Direction No. 7 requires the Commission to approve the portions of the allowed revenue requirement not recovered by the rate increases directed by Direction No. 7 be deferred to the Rate Smoothing Regulatory Account (RSRA);

C. By Orders G-130-16A, G-144-16 and G-7-17 dated August 9, 2016, September 7, 2016 and January 20, 2017, respectively, the Commission established a regulatory timetable and a written hearing process for the review of the Application, which included two rounds of information requests (IR) to BC Hydro, Intervener Evidence and IRs on that evidence, Rebuttal and additional evidence from BC Hydro and IRs on that evidence, followed by final and reply arguments from all parties. The regulatory timetable was further amended through Orders G-20-17 and G-50-17 on February 17, 2017 and March 30, 2017, respectively;

D. BC Hydro's Final Argument and Intervener Final Arguments were submitted on May 23, 2017 and June 13, 2017, respectively, followed by a Reply Argument from BC Hydro on July 4, 2017;

E. On November 8, 2017, BC Hydro requested certain amendments to its fiscal 2019 rates, in particular, BC Hydro seeks approval to:

   1. change its requested rate increase for fiscal 2019 from 3 percent to 0 percent, and
   2. maintain its 2018 Open Access Transmission Tariff rates for fiscal 2019 (Amended Application);

F. BC Hydro submits in its Amended Application that the portions of the allowed revenue requirement not recovered in rates in fiscal 2019 are to be deferred to the RSRA consistent with Direction No. 7 to the Commission. The resulting impact is expected to increase the transfer to the RSRA in fiscal 2019 by approximately $140 million;

G. By Order G-171-17 dated November 27, 2017, the Commission established a regulatory timetable for the review of the Amended Application. The regulatory timetable was further amended through Commission letters dated December 7, 2017 and December 13, 2017;

H. BC Hydro's Final Argument and Intervener Final Arguments regarding the Amended Application were submitted on December 21, 2017 and the period from January 11 to 16, 2018, respectively, followed by a Reply Argument from BC Hydro on January 19, 2018; and

I. The Commission has considered the Application, the Amended Application and the evidence and submissions filed in the proceeding and makes the following determinations.

NOW THEREFORE, pursuant to sections 58–61 of the *Utilities Commissions Act*, and for the reasons outlined in the decision issued concurrently with this order, the Commission orders as follows:

1. The requested final rate increases of 4.0 percent, 3.5 percent and 3.0 percent to be applied as set out in Appendix T of the Application, are approved effective April 1, 2016, April 1, 2017 and April 1, 2018, respectively.

2. The requested final OATT rates for fiscal 2017, fiscal 2018 and fiscal 2019 as set out in Appendix T of the Application, and as corrected in Errata No. 1 are approved effective April 1, 2016, April 1, 2017 and April 1, 2018, respectively. The difference between the final OATT rates and the interim refundable OATT rates is to be collected from applicable OATT customers through a one-time charge as described in Chapter 9 of the Application.

3. BC Hydro is directed to re-calculate its revenue requirements, including its rate of return, based on the updates, errata and commitments made by BC Hydro as summarized in Part Thirteen of its Final Submission and the Commission directives in the proceeding.

4. Pursuant to Direction No. 7, BC Hydro is directed to record in the RSRA for each year of the test period the difference between BC Hydro's recalculated revenue requirements and the revenues expected to be collected under the approved rates.

5. The requested depreciation rates for property, plant and equipment at the Burrard synchronous condense facility as set out in Table 8-1 of the Application are approved.

6. The requested changes to deferral and regulatory accounts and associated financial treatment, as described in Chapter 7 and summarized in Table 7-9 of the Application and clarified in Part Nine E and F of the Final Submission, are approved, with certain exceptions as described in sections 3.4.2 and 3.4.4 of the Decision accompanying this order.

7. The requested demand side management expenditure schedule for fiscal 2017, fiscal 2018 and fiscal 2019, as set out in Table 10-1 of the Application and revised in BC Hydro's response to BCUC IR 314.3, is accepted, for a total expenditure over the test period of $361.1 million.

8. BC Hydro is directed to file within 60 days of this order a revised Appendix A to the Application and updated rate schedules, reflecting the Commission's Order and Decision and BC Hydro's commitments articulated in Part Thirteen of its Final Submission.

9. BC Hydro is directed to comply with all other directives in the Decision accompanying this order.

DATED at the City of Vancouver, in the Province of British Columbia, this *1st* day of March 2018.

BY ORDER

Original signed by:

D. M. Morton
Commissioner

Glossary of Terms

Acronym	Description
ACEEE	American Council for an Energy-Efficient Economy
AMPC	Association of Major Power Customers of British Columbia
Application	BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application
BC Hydro, Company	British Columbia Hydro and Power Authority
BCEAA	British Columbia Environmental Assessment Act
BCOAPO	British Columbia Old Age Pensioners' Organization, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre
BCSEA	British Columbia Sustainable Energy Association and Sierra Club of British Columbia
CEA	*Clean Energy Act*
CEABC	Clean Energy Association of BC
CEC	Commercial Energy Consumers Association of British Columbia
Commission, BCUC	British Columbia Utilities Commission
COS	cost of service
COSS	Cost of Service Study
CPCN	Certificate of Public Convenience and Necessity
DARR	Deferral Account Rate Rider
DCRA	Dismantling Cost Regulatory Account
Direction No. 7	Direction No. 7 to the British Columbia Utilities Commission, OIC 097/2014 and amended OIC 405/2015
DSM	Demand-Side Management
DSM Regulation	Demand-Side Measures Regulation, BC Reg. 326/2008
EARSL	expected average remaining service life
EM&V	evaluation, measurement and verification
EPA	energy purchase agreement
F2017	Fiscal 2017
F2018	Fiscal 2018
F2019	Fiscal 2019

FBC	FortisBC Inc.
FortisBC	FortisBC Energy Inc., and FortisBC Inc.
FTE	Full Time Employee(s)
GHG	greenhouse gas
HDA	Heritage Deferral Account
HLH	High Load Hours
IFRS	International Financial Reporting Standards
IPP	Independent Power Producer
IR	information requests
IRP	integrated resource plan
IT&T	information technology and telecommunication
Johansson	Ms. Gwen Johansson
Landale	Mr. Richard Landale
LGIC	Lieutenant Governor in Council
LGS	Large General Service
Little	Mr. James and Mrs. Margaret Little
LNG	liquefied natural gas
LRB	Load-Resource Balance
LRMC	Long Run Marginal Cost
McCandless	Mr. Richard McCandless
MEM	British Columbia Ministry of Energy and Mines
MGS	Medium General Service
MoveUp	Movement of United Professionals
NHDA	Non-Heritage Deferral Account
NIARG	Non-Integrated Areas Ratepayers Group
NIAs	Non-Integrated Areas
NSA	Negotiated Settlement Agreement
NSP	Negotiated Settlement Process
O&M	operating and maintenance

OATT	Open Access Transmission Tariff
OPEB	other post employee benefits
PBR	Performance Based Rates
PCB	Polychlorinated Biphenyl
PEB	Post-employment benefit
PPA	Power Purchase Agreement
PRES	Peace Region Electric Supply project
PRRD	Peace River Regional District
RIB	Residential Inclining Block
RRA	Revenue Requirements Application
RS	Rate Schedule
RSRA	Rate Smoothing Regulatory Account
SGS	Small General Service
Skywind	Skywind Foundation
SMI	Smart Metering Infrastructure
SONS	Save Our Northern Seniors
TCE	TransCanada Energy Ltd.
TIDA	Trade Income Deferral Account
TMP	Thermo-Mechanical Pulp
TRR	Transmission Revenue Requirement
TS	Tariff Supplement
TSR	Transmission Service rate
UCA	*Utilities Commission Act*
WACD	Weighted Average Cost of Debt
Zone II	Zone II Ratepayers Group

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British Columbia Hydro and Power Authority

F2017 to F2019 Revenue Requirements Application

Key Findings – Load Forecast

August 25, 2017

Before:
D. M. Morton, Panel Chair
K. A. Keilty, Commissioner
D. J. Enns, Commissioner

British Columbia Hydro and Power Authority
F2017 to F2019 Revenue Requirements Application

Key Findings – Load Forecast

Table of Contents

1.0 Preface

On July 28, 2016, the British Columbia Hydro and Power Authority (BC Hydro, the authority) filed its Fiscal 2017 to Fiscal 2019 (F2017 to F2019) Revenue Requirements Application (Application) pursuant to sections 59 to 60 of the *Utilities Commission Act* (UCA) requesting, among other things:

- Final approval to increase rates by an average of 4.0 percent effective April 1, 2016, 3.5 percent effective April 1, 2017 and 3.0 percent effective April 1, 2018, which reflect the rate caps set out in Direction No. 7;
- Final approval of Open Access Transmission Tariff rates effective April 1, 2016, April 1, 2017 and April 1, 2018 as set out in the Application;
- Approval for changes and additions to certain regulatory and deferral accounts; and
- Acceptance of the demand-side measurements expenditure schedules under section 44.2 of the UCA.

On August 2, 2017, the Lieutenant Governor in Council, by Order in Council (OIC) No. 244, requested the British Columbia Utilities Commission (Commission), pursuant to section 5(1) of the UCA, to advise the Lieutenant Governor in Council respecting BC Hydro's Site C project in accordance with the terms of reference set out in section 3 of OIC No. 244 (Site C Inquiry). On August 8, 2017, in response to the OIC, the Commission initiated the Site C Inquiry.

Section 3(c) of OIC No. 244 states that in making its applicable determinations, the Commission:

> … must use the forecast of peak capacity demand and energy demand submitted in July 2016 as part of the authority's [BC Hydro's] Revenue Requirements Application, and must require the authority [BC Hydro] to report on
>
> (i) developments since that forecast was prepared that will impact demand in the short, medium and longer terms, and
>
> (ii) other factors that could reasonably be expected to influence demand from the expected case toward the high load or the low load case;

In light of the requirement for the Commission to review additional details related to BC Hydro's 2016 load forecast as part of the Site C Inquiry, the Panel considers it appropriate to provide its findings on the 2016 Load Forecast for the fiscal 2017 to fiscal 2019 test period (three-year test period) in advance of issuing its full decision on the remaining issues and determinations on approvals sought in the Application which is to be issued by the Commission in due course.

2.0 Introduction

In the Application, BC Hydro seeks, among other things, approval of rates for the three year test period.[1] BC Hydro states that the first three years of the May 2016 Load Forecast are key inputs for its Revenue Forecast and the Cost of Energy for the test period (fiscal 2017 to fiscal 2019). The Load Forecast is also a key input for BC Hydro's Load Resource Balances and its 10 Year Rates Plan.[2] However, it further stated that the longer term

[1] Exhibit B-1-1, p. 1-1.
[2] Exhibit B-1-1, pp. 3-1 – 3-2.

forecast beyond fiscal 2019 is provided for context in this application and that BC Hydro will update its load forecast in the 2018 Integrated Resource Plan (IRP).[3]

BC Hydro also states that the load forecast provided in the Application is lower than the forecasts provided by BC Hydro in the 2013 IRP which were used as an input into the 2013 10 Year Rates Plan. BC Hydro indicates that developments in recent months have amplified this issue and illustrate the fact that load forecasting is inherently an uncertain undertaking.[4]

BC Hydro explained in response to BCUC IR 4.7 that the load forecast presented in the Application will also be used internally for many purposes such as load resource balance planning, monthly energy studies, long term transmission planning studies, and demand-side management planning.[5] BC Hydro stated that it:

> … updates our load forecast annually and as circumstances dictate and would use the most current load forecast available. BC Hydro will consider any Commission determination and comments as we continue to update our load forecast. We will also consider new information that becomes available. [6]

BC Hydro indicated that a new load forecast will be completed in 2017 for input into the 2018 IRP.[7] BC Hydro also stated that the test period load forecast may be used to support the analysis of need and cost effectiveness of an Electricity Purchase Agreement (EPA) renewal.[8]

3.0 Legislative framework

The context for the Panel's review of the 2016 Load Forecast and associated revenue forecast is to find whether or not the forecasts are reasonable for use in the three-year test period in order to determine if the approvals sought comply with sections 59–60 of the UCA as well as the other elements of the legislative framework as summarized in Section 2.4 of the Application.

BC Hydro is exempt from section 44.1 of the UCA which addresses long-term resource planning by public utilities.[9] The *Clean Energy Act* (CEA) requires BC Hydro to submit its integrated resource plan to the minister for approval and identifies load forecasting as a key element of the integrated resource plan, thereby limiting the Commission's jurisdiction over BC Hydro's long-term load forecast. Section 3 of the CEA states that:

> The authority must submit to the minister, in accordance with subsection (6), an integrated resource plan that is consistent with good utility practice and that includes all of the following:
>
> (a) a description of the authority's forecasts, over a defined period, of its energy and capacity requirements to achieve electricity self-sufficiency…
>
> (b) a description of the consultations carried out by the authority respecting the development of the integrated resource plan…

[3] Exhibit B-14, BCUC IR 195.1.1.
[4] Exhibit B-1-1, p. 1-8.
[5] Exhibit B-9, BCUC IR 4.7.
[6] Exhibit B-14, BCUC IR 195.3.
[7] Exhibit B-14, BCUC IR 195.3.
[8] Exhibit B-14, BCUC IR 195.4.
[9] BC Hydro Reply Argument, p. 37.

Accordingly, the focus of the Panel's review of the load forecast and associated revenue forecast is on the three-year test period since long-term planning is either governed by other legislative parameters or addressed in other processes.

With respect to actual variances from the revenue forecast in the test period, Direction No. 7 (7)(c)(i) to the Commission states:

> When regulating and setting rates for the authority, the commission must, in regard to the non-heritage deferral account (NHDA), allow the authority to continue to defer to that account the variances between actual and forecast cost of energy arising from differences between actual and forecast domestic customer load.

In addition to providing variance protection for the revenue forecast as noted above, Direction No. 7 (9) to the Commission also directed the Commission to establish the rate smoothing account to defer for recovery in rates in future years, those portions of the allowed revenue requirement in a particular fiscal year that were not, or are not to be recovered in rates in that particular year.[10] Direction No. 7(9) states:

> (1) When regulating and setting rates for the authority for F2017, F2018 and F2019, under sections 4, 5, 6, 7, 9 (2), 10 (3) and 11 of this direction, the commission must not allow the rates to increase by more than 4% in F2017, 3.5% in F2018 and 3% in F2019, on average, compared to the rates of the authority immediately before the increase.
>
> (2) If the base line rate change exceeds 4% in F2017, 3.5% in F2018 or 3% in F2019, the commission must order the authority to defer to the rate smoothing regulatory account the amount that is determined by subtracting the amount in paragraph (b) from the amount in paragraph (a)
>
> (a) the forecast revenue that the authority would have earned under a base line rate change, and
> (b) the forecast revenue that the authority is expected to earn under this direction.

4.0 Key issues arising

BC Hydro submits the Commission should find that the Load Forecast and Revenue Forecast for the test period are reasonable.[11] In its reply argument, BC Hydro summarizes the views of interveners as follows:

> Five interveners have commented on load forecasting in their submissions. Their views diverge. NIARG submits that the test period Load Forecast "appear[s] to be reasonable". BCOAPO also generally accepts BC Hydro's forecast for use in setting rates for the test period. AMPC advocates changes to the methodology prospectively, but does not recommend adjustments to the test period forecast. Only CEABC and CEC advocate adjusting the test period Load Forecast
>
> …
>
> CEABC argues the forecast is too low, while CEC argues it is too high.[12]

[10] Exhibit B-1-1, p. 7-43.
[11] BC Hydro Final Argument, p. 26.
[12] BC Hydro Reply Argument, pp. 14– 15.

Based on its review of the evidence and considering the arguments of the parties, the Panel has identified the following key issues to be addressed in its findings on the reasonableness of the load forecast and associated revenue forecast for the three-year test period:

1. Scope and purpose;
2. Industrial elasticity; and
3. Load forecast methodology and variance treatment.

4.1 Scope and purpose

BC Hydro confirmed that the longer term forecast beyond fiscal 2019 is provided for context in the Application and states that BC Hydro will update its load forecast in the 2018 IRP.[13]

Some interveners in the proceeding argue that BC Hydro should use its updated load forecast to inform other issues. For example, the Non-Integrated Areas Ratepayers Group (NIARG) suggests that BC Hydro use "the best available information" for operational decisions and any EPA filings under section 71 of the UCA.[14] The Commercial Energy Consumers Association of British Columbia (CEC) submits that the 2016 Load forecast is high over the planning horizon and should be reforecast to avoid overspending on new energy resources that are not needed.[15] CEC further submits that an adjustment to the long-term forecast is required for appropriate Independent Power Producers (IPP) EPA planning.[16] The Association of Major Power Producers of British Columbia (AMPC) also has concern that extends beyond the test period as they are not convinced that the forecasts attributed to facilities under construction and yet to commence operations, should be considered reliable.[17]

Panel discussion

The Panel's review of BC Hydro's load forecast is focused on the F2017 to F2019 test period as inputs to calculating its revenue forecast and the cost of energy component of its proposed revenue requirement. The Panel makes no findings on any other purpose of the load forecast in this proceeding.

On January 27, 2017, the Commission issued Order G-7-17 and Reasons for Decision, which stated:

> The review of this Application is focused on setting BC Hydro's rates for F2017 though F2019.
>
> …
>
> BC Hydro has clarified that the load forecasts beyond the test period will be the subject of the 2018 Integrated Resource Plan. The Panel further recognizes that the Heritage Deferral Account (HDA) and the Non-Heritage Deferral Account (NHDA) are legislated to capture variances related to COE and revenue forecasts, which is impacted by the load forecast. In addition, there are further legislative parameters relating to the [Standing Offer Program] SOP and [Energy Purchase Agreements] EPAs.[18]

As noted above in the legislative framework section, section 3 of the CEA specifies that BC Hydro's integrated resource plans are submitted to the minister and include a description of the authority's forecasts, over a

[13] Exhibit B-14, BCUC IR 195.1.1.
[14] NIARG Final Argument, p. 10.
[15] CEC Final Argument, p. 15.
[16] CEC Final Argument, p. 30.
[17] AMPC Final Argument, p. 6.
[18] Order G-7-17, Appendix B, p. 13.

defined period, of its energy and capacity requirements to achieve electricity self-sufficiency. The Panel concurs with BC Hydro that only the test period load forecast is within scope of the Application and the long-term resource planning is appropriately addressed in BC Hydro's IRP file with the minister. In the Panel's view, giving direction to BC Hydro on its long term resource planning is outside the scope of this Application and is beyond the Commission's jurisdiction.[19]

4.2 Industrial elasticity

BC Hydro stated that it uses a use a facility-by-facility assessment of viability given commodity market conditions and prices for large industrials, rather than attempt to undertake individual sector elasticity studies. BC Hydro explains:

> The results of the analysis informs the probability weighting factors applied to all of the various electric intensive customers which make up the large industrial sector. Future rate increases impact future viability of these large industrial customers, but in general this is expected to be a secondary effect given the relative costs of electricity as a portion of total operating costs for some sectors.[20]

According to BC Hydro, light industrial loads consist of forestry, oil and gas, coal mines and other industrial customers connected at distribution voltage BC Hydro states:

> The forecast of sales to forestry, coal, and the oil and gas portion of the light industrial distribution sector is developed using production forecasts and information gathered from BC Hydro's key account managers for specific loads such as distribution coal mines or gas producers. The other industrial distribution loads are developed from a regression model, where the driver of the sales is real GDP for B.C. as this variable has a strong relationship to other industrial distribution loads.[21]

BC Hydro further explains that "the elasticity of -0.05 is applied to estimate the rate impact on BC Hydro's sales forecast. This calculation was applied uniformly across the sectors. It has not been applied for specific income level, end uses of electricity, season, electricity rate level, customer rate classes, location on the system, or duration of the forecast period."[22] BC Hydro stated it applies the common elasticity factor of -0.05 to all customer classes and explains that its assumption of -0.05 is based on the direct testimony of Dr. Ren Orans as contained in its 2008 Long Term Acquisition Plan (LTAP) Application to the Commission.[23]

In contrast, AMPC stated that "the remedy for the industrial revenue calculation following a rate increase is the use of an industrial price elasticity figure larger than -0.05, and a more detailed revenue calculation (as distinct to a load forecast) by individual industrial facilities that includes a 'feedback' step."[24] AMPC also stated that BC Hydro's most recent analysis in its F2010 Demand-Side Management Milestone Evaluation Summary Report indicates a -0.16 price elasticity for industrial customers.[25]

In its final argument, AMPC recommends that the Commission direct BC Hydro to recognize the risk of increasing rates to industrial customers by replacing the universal price elasticity factor of -0.05 applied to industrial customers in favour of a higher price elasticity factor that more realistically captures the effect of cumulative

[19] BC Hydro Reply Argument, p. 37.
[20] Exhibit B-10, AMPC IR 1.3.2.
[21] Exhibit B-1-1, p. 3-8.
[22] Exhibit B-10, AMPC IR 1.3.2.
[23] Exhibit B-20, p. 18; Exhibit B-22, CEABC IR 3.46.1.
[24] Exhibit C9-9, BCSEA IR 2.2.
[25] Exhibit C9-9, BCESA IR 2.2.

rate impacts on more price sensitive energy intensive and trade-exposed industrial customers, and introduce conservatism to the load forecasting methodology by building in a transparent "iterative step" or price feedback mechanism to the facility based industrial load forecast, explicitly considering the production shifting risk of the rate increase(s) proposed for the test period.[26]

BC Hydro explained that the methodology it uses to forecast industrial load accounts for elasticity and the "stepwise nature" of industrial demand.[27] BC Hydro states it assesses the future viability of their customers and their loads by undertaking a facility-by-facility assessment considering a number of factors, including cost issues. BC Hydro argues that a facility-by-facility assessment addresses the same load impacts due to cost pressures, but is a more granular and timely assessment than applying a further class average elasticity response. [28]

With respect to AMPC's comments on BC Hydro's forecasting methodology as it relates to price elasticity, BC Hydro submits there is no need to use a class specific elasticity factor since the impact of prices is already reflected in its customer-specific assessment.[29]

Panel discussion

The Panel acknowledges the concerns of AMPC regarding the price elasticity used for industrial customers and notes that it does not suggest adjustments for the test period but rather argues for changes going forward. The Panel also acknowledges BC Hydro's observation that using a higher elasticity factor (such as the -0.16 cited by AMPC), without recognizing that the impact of prices is already reflected in the customer-specific assessment, would therefore lead to double-counting.[30]

Notwithstanding, the Panel observes that the capped rate increases for 2017, 2018 and 2019 have been prescribed by Direction No.7 at 4.0 percent, 3.5 percent and 3.0 percent, respectively. The Panel accepts these increases were known to industrial customers when BC Hydro's key account managers conducted their forecast surveys. Accordingly, the Panel is satisfied that the issue of price elasticity for future, unknown price increases is not an issue in the test period.

4.3 Load forecast methodology and variance treatment

BC Hydro states that previous Commission "reviews of the Load Forecast, such as the review undertaken for BC Hydro's 2008 Long Term Acquisition Plan (LTAP) proceeding, concluded that BC Hydro's Load Forecast was acceptable. The Government's review of BC Hydro in 2011 indicated its forecasting process is well planned, and produces reliable results."[31] In response to BCUC IR 2.2, BC Hydro provided a comparison of its current methodology with the methodology reviewed in the BC Government Review in 2011 and BCUC Review of 2008 LTAP, and provides justification for any change.

BC Hydro explained that there have been no major changes in the current large industrial forecast methodology compared to the methodology in the BC Government's review in 2011 and the BCUC's review of BC Hydro's 2008 LTAP.[32] There have been changes to the methodology to enhance the accuracy of the chemical sector sales forecast. The prior methods used regression analysis and a forecast of provincial GDP growth to estimate sales for the last 10 years of forecast.[33] Liquefied natural gas (LNG) loads were based on a probability weighting of

[26] AMPC Final Argument, p. 2.
[27] Exhibit B-20, p. 17.
[28] Exhibit B-20, p. 18.
[29] BC Hydro Reply Argument, p. 43.
[30] BC Hydro Reply Argument, pp. 43 – 44.
[31] Exhibit B-1-1, p. 3-3.
[32] Exhibit B-9, BCUC IR 2.2.
[33] Exhibit B-9, BCUC IR 2.2.

load requests from LNG proponents. In the current methodology, LNG plant loads are based on public information announced by LNG proponents and for which BC Hydro has received service requests.[34]

BC Hydro states it delayed filing the Application to allow BC Hydro to update the Load Forecast and the Load Resource Balances to reflect the current outlook of certain sectors, including more recent developments in mining and LNG plant loads. BC Hydro states that the updated load forecast, while continuing to predict long-term load growth across all three customer sectors, yielded a lower growth rate compared to the 2013 IRP.[35]

BC Hydro presented the Domestic Sales Variance Average for Seven and Eight Years:

[34] Exhibit B-9, BCUC IR 2.2.
[35] Exhibit B-1-1, Application, p. 3-1.

Table 1 – Total Domestic Sales Variance for Averages of Seven and Eight Years [36]

	Sector	A	B	Forecast Vintage	C=A-B	D=(A-B)/B
	Fiscal 2016	F2016 Actual (GWh)	F2016 RRA (GWh)	Oct-13	Difference (GWh)	Per Cent Difference %
1	Residential	17,331	18,743		(1,412)	-7.5%
2	Light Industrial and Commercial	18,421	18,346		75	0.4%
3	Large Industrial	13,669	15,032		(1,363)	-9.1%
4	Other	1,602	1,639		(37)	-2.3%
5	Total Mid Domestic Sales	51,023	53,760		(2,738)	-5.1%
	Fiscal 2015	F2015 Actual (GWh)	F2015 RRA (GWh)	Oct-13	Difference (GWh)	Per Cent Difference %
6	Residential	17,047	18,805		(1,758)	-9.3%
7	Light Industrial and Commercial	18,564	18,277		287	1.6%
8	Large Industrial	14,020	14,444		(423)	-2.9%
9	Other	1,567	1,604		(37)	-2.3%
10	Total Mid Domestic Sales	51,199	53,130		(1,932)	-3.6%
	Fiscal 2014	F2014 Actual (GWh)	F2014 RRA (GWh)	Mar-11	Difference (GWh)	Per Cent Difference %
11	Residential	17,965	18,057		(91)	-0.5%
12	Light Industrial and Commercial	18,501	17,681		821	4.6%
13	Large Industrial	13,994	16,519		(2,526)	-15.3%
14	Other	1,550	2,099		(549)	-26.2%
15	Total Mid Domestic Sales	52,010	54,356		(2,346)	-4.3%
	Fiscal 2013	F2013 Actual (GWh)	F2013 RRA (GWh)	Mar-11	Difference (GWh)	Per Cent Difference %
16	Residential	17,703	18,210		(507)	-2.8%
17	Light Industrial and Commercial	18,384	17,930		455	2.5%
18	Large Industrial	13,508	15,315		(1,807)	-11.8%
19	Other	1,397	2,072		(676)	-32.6%
20	Total Mid Domestic Sales	50,992	53,527		(2,535)	-4.7%
	Fiscal 2012	F2012 Actual (GWh)	F2012 RRA (GWh)	Mar-11	Difference (GWh)	Per Cent Difference %
21	Residential	18,395	18,213		182	1.0%
22	Light Industrial and Commercial	18,005	18,209		(204)	-1.1%
23	Large Industrial	13,522	14,451		(929)	-6.4%
24	Other	1,565	2,045		(480)	-23.5%
25	Total Mid Domestic Sales	51,487	52,919		(1,431)	-2.7%
	Fiscal 2011	F2011 Actual (GWh)	F2011 RRA (GWh)	Jul-09	Difference (GWh)	Per Cent Difference %
26	Residential	17,797	17,365		432	2.5%
27	Light Industrial and Commercial	18,052	18,247		(195)	-1.1%
28	Large Industrial	13,164	14,153		(989)	-7.0%
29	Other	1,594	2,029		(435)	-21.4%
30	Total Mid Domestic Sales	50,607	51,794		(1,187)	-2.3%
	Fiscal 2010	F2010 Actual (GWh)	F2010 RRA (GWh)	Oct-08	Difference (GWh)	Per Cent Difference %
31	Residential	17,593	16,967		626	3.7%
32	Light Industrial and Commercial	17,811	18,586		(775)	-4.2%
33	Large Industrial	13,020	15,240		(2,220)	-14.6%
34	Other	1,809	1,829		(20)	-1.1%
35	Total Mid Domestic Sales	50,233	52,622		(2,389)	-4.5%
	Fiscal 2009	F2009 Actual (GWh)	F2009 RRA (GWh)	Oct-08	Difference (GWh)	Per Cent Difference %
36	Residential	17,861	17,264		597	3.5%
37	Light Industrial and Commercial	18,265	18,445		(180)	-1.0%
38	Large Industrial	14,303	15,228		(926)	-6.1%
39	Other	1,887	1,765		122	6.9%
40	Total Mid Domestic Sales	52,316	52,702		(386)	-0.7%
	Average last seven years					
41	Residential	17,690	18,051		(361)	-1.9%
42	Light Industrial and Commercial	18,248	18,182		66	0.4%
43	Large Industrial	13,557	15,022		(1,465)	-9.6%
44	Other	1,583	1,902		(319)	-15.6%
45	Total Mid Domestic Sales Average last seven years	51,079	53,158		(2,080)	-3.9%
	Average last eight years					
46	Residential	17,713	17,916		(203)	-1.0%
47	Light Industrial and Commercial	18,231	18,256		(25)	-0.1%
48	Large Industrial	13,670	15,010		(1,339)	-8.8%
49	Other	1,653	1,859		(205)	-10.0%
50	Total Mid Domestic Sales Average last eight years	51,268	53,040		(1,773)	-3.3%

[36] Exhibit B-9, BCUC IR 4.3.

BC Hydro stated that the data on the variance for each sector shows that, on average, the total domestic sales forecast exceeded actuals by 3.9 percent over the last seven years and by 3.3 percent over the last eight years. The average variance in the residential sector and light industrial and commercial sector actuals were lower than the forecast by only about 1 percent and 0.1 percent, respectively.[37]

BC Hydro states that the total domestic sales variance is primarily due to the large industrial sector, which accounts for about 75 percent of the average domestic sales variance over the last eight years. Further examination of the large industrial class indicates the variance is attributed to large discrete customer load attrition events and other external factors that could not have been reasonably foreseen. Other external factors include fluctuations in global commodity demand and prices which vary from those reflected in the mid load forecast projections. The outcomes of these external factors are delayed requests for electricity service from large industrial customers and temporary shutdowns.[38]

Despite the results shown in the table above, BC Hydro believes that its approach to forecasting large industrial load remains appropriate and that past variances have resulted from unforeseen circumstances that would have been difficult, if not impossible, to predict. BC Hydro further states that in terms of the recent cycle of lower than forecast large industry loads, the length of the down-cycle was unforeseen and there were plant closures for other reasons like water availability that compounded the situation. BC Hydro expects that, as is currently being seen, commodity prices will recover and associated load growth is expected to occur.[39]

Intervener arguments

While several interveners provided various submissions on BC Hydro's load forecast, most do not suggest an adjustment to the forecast presented for the test period. The exceptions are as follows:

- The CEC advocates for an overall downward adjust to the load forecast: a reduction in load forecast of 1 % for 2017, 2% for 2018 and 3% for 2019, reducing revenue forecast by $43 million in 2017 and by $86 million in 2018 and by $132 million in 2019. The CEC believes that this would be a step toward having BC Hydro achieve a better balance between over and under forecasting to establish an improvement to the base for appropriate rate setting.[40] The CEC also submit that because the variances from forecast are captured in the NHDA, it would be appropriate for BC Hydro to achieve a better balance.[41]
- The Clean Energy Association of BC (CEABC) submits that the pace of raw gas production in the Montney is greatly exceeding BC Hydro's forecast, and recommends that the Commission direct BC Hydro to immediately revise its Montney raw gas production forecast to reflect the reality of increasing production and investment.[42]

Panel discussion

As noted in the legislative framework section above, the Panel's review of the 2016 Load Forecast and associated revenue forecast is to find whether or not the forecasts are reasonable for use as key input in the three-year test period in order to determine if the approvals sought comply with sections 59–60 of the UCA as well as the other elements of the legislative framework as summarized in Section 2.4 of the Application. While a specific approval for the three-year test period load forecast is not required, the Panel recognizes that it is a key input into its cost of energy forecast and its calculation of the domestic revenue forecast for each year of the

[37] Exhibit B-9, BCUC IR 4.3.
[38] Exhibit B-9, BCUC IR 4.3.
[39] Exhibit B-14, BCUC IR 200.2.
[40] CEC Final Argument, p. 6.
[41] CEC Final Argument, p. 74.
[42] CEABC Final Argument, p. 20.

test period. BC Hydro's Non-Heritage Deferral Account (NHDA) captures many variances, and as illustrated in the table below, with the largest impact attributed to the domestic load forecast variances:

Table 2 – Non-Heritage Deferral Account Annual Summary[43]

Non-Heritage Deferral Account Annual Summary

Year	Reported Opening Balance	Cost of Energy	Commodity Risk	Notional Water Rental	FX Gains & Losses on Powerex Trade	Domestic Revenue Variance (2009)	ABSU Founding Partner Benefits	Deferred Operating Costs in NHDA	RRA Adjustments	PTP and NITS Variance	Capital Lease Adjustment	Burrard Costs	Other	Total Changes	Rounding	Amortization	Interest	Ending Balance
F2005	0.0	154.5	-5.3	-10.7	-10.6									127.9			3.0	130.9
F2006	130.9	44.7	19.8	0.2	-3.9		-0.6	7.3	-2.9					64.6	0.1		9.0	204.6
F2007	204.6	35.5	3.3	-4.9	4.9		-0.0	-2.7						35.5		-45.3	14.0	208.8
F2008	208.8	54.3	3.0	2.9	18.6		0.5		33.7					107.2	0.1	58.9	8.8	51.6
F2009	51.6	-51.5	9.7	-0.7	9.7	20.4	-0.5		43.2					30.3		-14.9	7.4	74.4
F2010	74.4	-22.8	-0.4	-9.3	-4.5	82.5	-0.6							44.9		-6.6	6.8	119.5
F2011	119.5	-44.5	-12.1	-1.6	-4.0	42.4	-0.2		262.9	16.0				258.9		-23.5	7.3	362.2
F2012	362.2	147.0	12.9	18.9	2.4	62.8	0.6	11.2	65.9	0.3				28.0	0.3	39.8	16.9	367.0
F2013	367.0	-166.5		5.1	-3.9	176.1	0.4		103.2	-12.2			62.2	164.3	-0.1	-84.0	20.3	467.5
F2014	467.5	-195.5	15.2	-14.9		137.7		-0.9	49.8	5.3				-3.3	0.0	-120.3	17.7	361.6
F2015	361.6	50.7	-4.8	-5.1		207.3				8.8	-22.8	4.1		238.2	0.1	-90.6	14.8	524.1
F2016	524.1	235.4	0.5	1.9		268.9				0.7	31.0	9.0		483.0	0.1	117.7	27.5	916.8
Cummulative Total		-161.4	34.8	-18.2	-28.5	998.1	-2.0	14.9	488.4	17.5	-53.8	13.1	62.2	1,365.1	-0.2	-601.6	153.5	

The Panel observes that all of the other balances in the NHDA have been both positive and negative in the past, thereby capturing the intent and purpose behind a variance account treatment. The exception is the domestic revenue variance, which has held a consistent and growing negative variance. Because BC Hydro's actual load has been less than its forecast since F2009, there have been significant additions to the NHDA every year. The Panel observes that the annual variance related to domestic revenues has steadily increased from $20 million in F2009 to $269 million in F2016 for total additions of $998 million in 8 years. On average the variance has been $125 million per year over the fiscal 2009 to fiscal 2016 period and the average annual addition has been $171 million over the last five-year (i.e., fiscal 2012 to fiscal 2016) period.[44]

In reviewing the fiscal 2017 to fiscal 2019 domestic energy sales forecast, the Panel uses BC Hydro's Table 3-4 on page 3-20 of the Application and includes the highlighted columns comparing the F2017 Plan as provided for in the interim application (February 2017) and the F2017 Actual filed in the eventual Application (July 2017):

Table 3 – 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 (interim Rates)	F2017 Plan	F2017 Actual	F2018 Plan	F2019 Plan
	A	B	C	D	E	F	G	H	I
Residential	18,805	17,047	18,743	17,331	n/a	18,039	17,989	18,112	18,250
Light Industrial and Commercial	18,277	18,564	18,346	18,421	n/a	18,832	18,847	18,785	18,899
Large Industrial	14,444	14,020	15,032	13,669	n/a	13,380	13,235	13,323	13,882
Other	1,604	1,567	1,638	1,602	n/a	1,611	1,682	1,618	1,634
Total	53,130	51,199	53,759	51,023	53,352 *	51,860	51,753	51,838	52,664
*	Exhibit B-1, Appendix B, Schedule 4, L16						-0.21%	(G/F)-1	
							-3.00%	(G/E)-1	

[43] Exhibit B-9, BCUC IR 126.1.
[44] Exhibit B-9, BCUC IR 1.124.7.

The Panel observes that even though the F2017 actuals are in line with BC Hydro's current forecast (a 0.21% variance)(Column G compared to Column F), the F2017 actual is a negative 3 percent variance from the forecast originally filed in the interim application (Column G compared to Column E).

As stated by BC Hydro, the large portion of the historical load variance is related to the industrial sector, which includes three major resource-based subsectors that make up the most of the large industrial load: oil and gas, mining, and forestry.[45] The Panel recognizes that there are inherent uncertainties and external factors such as political and social-economic factors that may have impact these industrial subsectors. Notwithstanding, BC Hydro suggests that there have been offsetting changes in industrial load which include positive developments and project restarts which will have an upward influence on the load forecast in the test period.[46]

In consideration of the above discussion, the Panel notes the following observations with respect to BC Hydro's 2016 Load Forecast:

- Since the 10 Year Rate Plan was first prepared in 2013, forecast revenues have declined by $3.5 billion, comprised mainly of reductions in forecast revenues from large industrial customers, reductions in the forecast growth of large industrial load, reductions in forecast revenues from LNG as a result in a shift of timing of this load, and reductions in revenues in fiscal 2015 and fiscal 2016 mainly due to warm winter weather, which reduced sales to residential customers.[47] BC Hydro does not believe the variance is a result of statistical bias in its load forecasting models, methodology or process. [48] BC Hydro states the total domestic sales variance is primarily due to the large industrial sector, and that past variances in large industrial load have resulted from unforeseen circumstances that would have been difficult, if not impossible, to predict.[49]
- Even though it identifies these challenges in forecasting revenues and states that variances are due to variables that are beyond its control, BC Hydro continues to forecast improvements in the industrial load forecast. The Panel notes that with regard to the test period, there is only a need to accurately predict the next three years. However, the historical variances in Table 1 indicate that there have been significant variances even one or two years into a forecast – for example in fiscal 2015, the variance of the residential class from the 2013 forecast amount was -9.5% and the fiscal 2012 industrial class variance was -11.8% from the 2011 forecast. The Panel takes some comfort in the fact that the first year of the test period has passed and the actuals for that year have tracked the forecast fairly closely. However, this result is not an indicator that the next two years will track accurately. The Panel further notes that other utilities such as Pacific Northern Gas Ltd., FortisBC Energy Inc., and FortisBC Inc. use a different load forecast methodology for their short term forecast for setting rates as compared to its long term forecast for resource planning.
- Notwithstanding the concern expressed above, we note that the forecast for the remaining two years of the test period do not reflect a significant upward trend. Further, the average of the forecast load for the next two years, 52,251 GWh, is virtually identical to the average of the actual load of 52,173 GWh for the past five years. The Panel is of the view that the forecast for the remaining two years of the test period appears reasonable given the current economic circumstances.[50]

[45] Exhibit B-9, BCUC IR 4.3; Exhibit B-14, BCUC IR 197.3.
[46] Exhibit B-14, BCUC IR 197.3.
[47] Exhibit B-10, BCOAPO IR 1.3.1.
[48] Exhibit B-9, BCUC IR 4.3.
[49] Exhibit B-9, BCUC 4.3; B-14, BCUC IR 200.2.
[50] Average of 2013–2017 actuals (53,130; 51,199; 53,759; 51,023; 51,753) = 52,173; Average of 2018 and 2019 forecast (51,838; 52,664) = 52,251. All figures are from Table 3.

The Panel notes the majority of interveners have not made a case for adjusting the load forecast in the test period. The Panel observes that, in the absence of a rate cap, a lower load forecast would result in a higher rate increase, and it is likely interveners are supportive of keeping actual rate increases lower than necessary.

- The use of the NHDA has inherent intergenerational equity concerns in that current period under-recoveries are shifted into the future. This can be seen by examining Table 2 above. There is almost one billion dollars that has accumulated in this account due to forecast variances over the past 8 years.
- The historical revenue variances related to the industrial sector also produces inter-class subsidization concerns. These revenue variances are recorded in the NHDA, and are recovered from ratepayers through the Deferral Account Rate Rider (DARR) which is then applied to all customers' bills.
- Any adjustments to BC Hydro's load forecast may impact the variances accruing into the NHDA. However under section 9 of Direction No. 7 to the Commission, the Panel's interpretation is that any variances related to BC Hydro's base line rate change above the rate caps established for each year of the test period will be deferred to BC Hydro's rate smoothing regulatory account. Accordingly, adjustments to the load forecast result in a shifting of variances from the NHDA regulatory account to the rate smoothing regulatory account. We have previously commented on the intergenerational inequity concerns associated with the NHDA; similar concerns arise with the use of the rate smoothing regulatory account.

Considering the discussion above, the Panel finds the 2016 Load Forecast reasonable for use in the F2017 to F2019 test period and declines to make any adjustments to the load forecast presented in the Application.

In the Panel's view, CEC's recommendations for an overall downward adjustment to the load forecast of 1 percent, 2 percent and 3 percent for the test period appear arbitrary, notwithstanding the attempts to "achieve a better balance."[51]

The Panel acknowledges BC Hydro's legislative framework and the requirement under Direction No. 7 for the Commission to continue to allow BC Hydro to defer its domestic revenue variances to the NHDA, and to allow BC Hydro base line rate change above the rate caps for each year of the test period to be deferred to BC Hydro's rate smoothing regulatory account.

As discussed above, given the rate caps, any adjustment to the load forecast in the test period would result in a shift from one regulatory account to another, thereby affecting only the timing of the recovery of the amount. The Panel notes amounts added to the NHDA in excess of $500,000 are recovered by the DARR mechanism. Given that the recovery mechanism for the rate smoothing regulatory account has not yet be established, in the Panel's view it is not possible to quantify the difference in these recovery mechanisms at this time. Both accounts may result in intergenerational inequity concerns if the recovery period is prolonged.

[51] CEC Final Argument, p. 74.

DATED at the City of Vancouver, in the Province of British Columbia, this *25th* day of August 2017.

D. M. Morton
Panel Chair / Commissioner

K. Keilty

K. A. Keilty
Commissioner

D. J. Enns
Commissioner

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
F2017 to F2019 Revenue Requirements Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated March 22, 2016 - Appointing the Commission Panel for the review of British Columbia Hydro and Power Authority F2017 to F2019 Revenue Requirements Application
A-2	Letter dated March 22, 2016 – Commission Order G-40-16 approving interim rates
A-3	Letter dated March 22, 2016 – Community Input Sessions
A-4	Letter dated May 16, 2016 – Community Input Sessions Information
A-4-1	Letter dated May 27, 2016 – Revised Community Input Sessions Information
A-5	Letter dated August 9, 2016 – Commission Order G-130-16 establishing Regulatory Timetable and Public Notice
A-5-1	Letter dated August 9, 2016 – Commission Order G-130-16A establishing Regulatory Timetable and Public Notice
A-6	Letter dated August 17, 2016 – Procedural Conference Information
A-7	Letter dated September 7, 2016 – Commission Order G-144-16 with reasons and Regulatory Timetable
A-8	Letter dated September 28, 2016 – Request for Submissions on Mr. Bryenton's Request to Intervene
A-9	Letter dated October 6, 2016 – Commission Information Request No. 1 to BC Hydro
A-10	**CONFIDENTIAL** letter dated October 6, 2016 – Confidential Commission Information Request No. 1 to BC Hydro (Web version Cover Letter only)

Exhibit No.	Description
A-11	Letter dated October 25, 2016 – Commission response to Mr. Bryenton's Request to Intervene
A-12	Letter dated November 16, 2016 – Procedural Conference Information
A-13	Letter dated December 2, 2016 – Further Written Submissions
A-14	Letter dated December 14, 2016 – Commission Information Request No. 2 to BC Hydro
A-15	**CONFIDENTIAL** letter dated December 14, 2016 – Confidential Commission Information Request No. 2 to BC Hydro (Web version Cover Letter only)
A-16	Letter dated January 6, 2017 – Supplemental Commission Information Request to IR No. 2
A-17	Letter dated January 20, 2017 – Commission Order G-7-17 with Regulatory Timetable and reasons to follow
A-18	Letter dated January 27, 2017 – Commission Order G-7-17 Reasons for Decision
A-19	Letter dated February 2, 2017 – Commission suspending Regulatory Timetable in response to AMPC request for an extension of the deadline for intervener evidence Exhibit C9-5
A-20	Letter dated February 3, 2017 – Commission extending Intervener Evidence Deadline
A-21	Letter dated February 9, 2017 – Commission request for regulatory timetable comments
A-22	Letter dated February 17, 2017 – Commission Order G-20-17 with Regulatory Timetable
A-23	Letter dated March 10, 2017 – Commission Information Request No. 1 to AMPC
A-24	Letter dated March 10, 2017 – Commission Information Request No. 1 to Zone II
A-25	Letter dated March 10, 2017 – Commission Information Request No. 1 to BCSEA
A-26	Letter dated March 16, 2017 – Commission Order G-39-17 regarding interim rates
A-27	Letter dated March 23, 2017 – Commission Order G-46-17 regarding interim OATT rates
A-28	Letter dated March 30, 2017 – Commission Order G-50-17 providing time in the regulatory timetable for information requests on new evidence
A-29	Letter dated April 24, 2017 – Commission Information Request No. 3 – Rebuttal Evidence and New Evidence
A-30	Letter dated April 25, 2017 – Commission response to Landale request in Intervener Evidence
A-31	Letter dated November 15, 2017 - Panel letter regarding Procedural Conference

Exhibit No.	Description
A-31-1	Letter dated November 21, 2017 – Correction regarding the PACA reference
A-32	Letter dated November 27, 2017 – Commission Order G-171-17 establishing a regulatory timetable
A-33	Letter dated December 1, 2017 – Commission Submitting Information Request on the Amended Application to BC Hydro
A-34	Letter dated December 7, 2017 – Commission correspondence amending the regulatory timetable
A-35	Letter dated December 13, 2017 – Commission correspondence amending the regulatory timetable
A-36	Letter dated January 22, 2018 – Commission Order G-16-18 establishing a regulatory timetable

COMMISSION STAFF DOCUMENTS

A2-1	Letter dated June 23, 2016 – Commission staff filing BCUC Community Input Sessions Staff Presentation – Participating in BCUC Proceedings
A2-2	Letter dated June 23, 2016 – Commission staff filing BCUC Community Input Sessions Staff Presentation – Regulatory Process

APPLICANT DOCUMENTS

B-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** letter dated February 26, 2016 – Application for approval of an interim refundable rate
B-1-1	Letter dated July 28, 2016 – BC Hydro Submitting Fiscal 2017 to Fiscal 2019 Revenue Requirements Application
B-1-1-1	**CONFIDENTIAL** Letter dated July 29, 2016 – BC Hydro Submitting Confidential Appendix J of the F2017-F2019 RRA Application
B-1-2	Letter dated August 18, 2016 - BC Hydro Submitting Errata No. 1 to the Application
B-1-3	Letter dated December 8, 2016 - BC Hydro Submitting Errata No. 2 to the Application
B-1-4	Letter dated December 21, 2016 - BC Hydro Submitting Appendix P Update - Smart Metering and Infrastructure Completion Report
B-1-5	Letter dated February 22, 2017 - BC Hydro Submitting Project Name Changes

Exhibit No.	**Description**
B-2	Letter dated August 17, 2016 - BC Hydro Submitting Evidentiary Update
B-3	Letter dated August 25, 2016 - BC Hydro Submitting copies of Appendix B as published in news publications
B-4	Letter dated August 29, 2016 - BC Hydro Submitting Outline of Procedural Conference submission
B-5	Letter dated September 23, 2016 - BC Hydro Submitting Demand-Side Management Information Responses
B-6	Letter dated September 23, 2016 - BC Hydro Submitting Further Information on F2015 and F2016 Capital Additions and Forecast Capital Projects over Test Period
B-7	Letter dated October 4, 2016 - BC Hydro Submitting response on Mr. Bryenton's Request to Intervene
B-8	**CONFIDENTIAL** Letter dated November 21, 2016 – BC Hydro Submitting Confidential Responses to BCUC Confidential Information Request No. 1 (Web version Cover Letter only)
B-9	Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 1
B-9-1	**CONFIDENTIAL** Letter dated November 21, 2016 – BC Hydro Submitting Confidential Responses to BCUC Information Requests No. 1 (Web version Cover Letter only)
B-9-1-1	**CONFIDENTIAL** Letter dated December 1, 2016 – BC Hydro Submitting Confidential Response to BCUC IR 1.5.1 Attachment 2 (Web version Cover Letter only)
B-9-2	Letter dated December 1, 2016 – BC Hydro Submitting Response to BCUC IR 1.5.1 Attachment 2 - Public Version
B-10	Letter dated November 21, 2016 – BC Hydro Submitting Responses to Interveners Information Request No. 1
B-10-1	**CONFIDENTIAL** Letter dated November 21, 2016 – BC Hydro Submitting Confidential Responses to Intervener Information Requests No. 1 (Web version Cover Letter only)
B-10-2	Letter dated December 1, 2016 – BC Hydro Submitting Response to AMPC IRs 1.4.2; 1.4.3; 1.4.7.2; 1.4.7.4; 1.4.7
B-11	Letter dated November 24, 2016 - BC Hydro Advanced Submission for Procedural Conference
B-12	Letter dated January 4, 2017 - BC Hydro Submitting Reply Submission

Exhibit No.	Description
B-13	**CONFIDENTIAL** Letter dated January 23, 2017 - BC Hydro Submitting Response to Confidential BCUC Information Request No. 2
B-14	Letter dated January 23, 2017 - BC Hydro Submitting Response to BCUC Information Request No. 2
B-14-1	**CONFIDENTIAL** Letter dated January 23, 2017 - BC Hydro Submitting Confidential Response to BCUC Information Request No. 2
B-14-1-1	**CONFIDENTIAL** Letter dated February 16, 2017 – BC Hydro Submitting Confidential Response to BCUC IR – Web cover letter
B-14-2	Letter dated February 16, 2017 – BC Hydro Submitting PUBLIC Response to BCUC IR
B-15	Letter dated January 23, 2017 - BC Hydro Submitting Responses to Intervener Information Request No. 2
B-15-1	**CONFIDENTIAL** Letter dated January 23, 2017 – BC Hydro Submitting Responses to Confidential Intervener Information Request No. 2
B-15-2	Letter dated February 16, 2017 – BC Hydro Submitting Responses to AMPC
B-15-3	Letter dated February 16, 2017 – BC Hydro Submitting Response to BCOAPO and CEA IR
B-15-4	Letter dated April 28, 2017 – BC Hydro Submitting revision to Attachment 1 to CEC IR 2.135.1
B-16	Letter dated February 14, 2017 – BC Hydro Submitting Regulatory Timetable Comments
B-17	Letter dated March 1, 2017 – BC Hydro Submission regarding Rate Schedules and updated Electric Tariff
B-18	Letter dated March 10, 2017 – BC Hydro Submission Providing notification of issuance of Order In Council No. 100 and 101
B-18-1	Letter dated March 13, 2017 – BC Hydro Correction of Submission Providing notification of issuance of Order In Council No. 100 and 101
B-19	Letter dated March 28, 2017 – BC Hydro Request for Confidential Information redacted in Zone II Responses to IRs
B-20	Letter dated April 5, 2017 –BC Hydro Submitting Rebuttal Evidence and information on the termination of Accenture contract
B-21	Letter dated May 11, 2017 –BC Hydro Submitting Responses to Commission IRs on Rebuttal Evidence

Exhibit No.	Description
B-21-1	**CONFIDENTIAL** Letter dated May 11, 2017 –BC Hydro Submitting Confidential Responses to Commission IRs on Rebuttal Evidence
B-22	Letter dated May 11, 2017 –BC Hydro Submitting Responses to Intervener IRs on Rebuttal Evidence
B-22-1	**CONFIDENTIAL** Letter dated May 11, 2017 –BC Hydro Submitting Confidential Responses to Intervener IRs on Rebuttal Evidence
B-22-2	Letter dated May 11, 2017 –BC Hydro Submitting Revision to CEA IR No. 3.46.1
B-23	Letter dated November 8, 2017 - BC Hydro Requesting Rate Freeze
B-24	Letter dated December 6, 2017 - BC Hydro Requesting Filing Extension
B-25	Letter dated December 15, 2017 - BC Hydro Submitting Responses to Commission and Intervener Information Request No. 4 on the Amended Application

INTERVENER DOCUMENTS

C1-1	**BC SUSTAINABLE ENERGY ASSOCIATION AND SIERRA CLUB BC (BCSEA)** Letter dated August 19, 2016 Request to Intervene by Thomas Hackney and William J. Andrews
C1-2	Letter dated October 1, 2016 - BCSEA Submission on Mr. Bryenton's Request to Intervene
C1-3	Letter dated October 19, 2016 – BCSEA Submitting IR No. 1 to BC Hydro
C1-4	Letter dated December 14, 2016 - BCSEA Submitting Comments on Process
C1-5	Letter dated December 14, 2016 - BCSEA Submitting IR No. 2 to BC Hydro
C1-6	Letter dated January 24, 2017 - BCSEA Submitting Confidentiality Declaration and Undertaking for Thomas Hackney, James Grevatt and William Andrews
C1-7	Letter dated February 2, 2017 - BCSEA Submitting Comments regarding AMPC request for an extension of the deadline for intervener evidence Exhibit C9-5
C1-8	Letter dated February 9, 2017 – BCSEA Submitting Intervener Evidence
C1-9	Letter dated February 10, 2017 – BCSEA Submitting Regulatory Timetable Comments
C1-10	Letter dated February 20, 2017 – BCSEA Submitting Request to Withdraw Confidential Access
C1-11	Letter dated March 10, 2017 – BCSEA Information Request No. 1 to AMPC
C1-12	Letter dated March 10, 2017 – BCSEA Information Request No. 1 to Zone II

Exhibit No.	Description
C1-13	Letter dated March 10, 2017 – BCSEA Information Request No. 1 to Landale
C1-14	Letter dated March 10, 2017 – BCSEA Information Request No. 1 to Clean Energy BC
C1-15	Letter dated March 27, 2017 – BCSEA response to BCUC A-25
C1-16	Letter dated March 27, 2017 – BCSEA response to CEABC C4-7
C1-17	Letter dated March 27, 2017 – BCSEA response to CEC C10-9
C1-18	Letter dated March 27, 2017 – BCSEA response to NIARG C11-9
C1-19	Letter dated April 24, 2017 – BCSEA Submitting IR No. 3 to BC Hydro
C1-20	Letter dated December 1, 2017 – BCSEA Submitting Information Request on the Amended Application to BC Hydro
C2-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION, LOCAL 378 (MOVEUP)** Letter dated August 17, 2016 Request to Intervene by Iain Reeve, Leigha Worth and Jim Quail
C2-2	Letter dated October 19, 2016 – MoveUp Submitting IR No. 1 to BC Hydro
C2-3	Letter dated December 13, 2016 – MoveUp Submitting Confidentiality Undertaking for A. Pullman
C2-4	Letter dated December 13, 2016 – MoveUp Submitting Confidentiality Undertaking for L. Worth
C2-5	Letter dated December 16, 2016 - MoveUp Submitting IR No. 2 to BC Hydro
C2-5-1	Letter dated January 6, 2017 – MoveUp Supplemental IR No. 2.1
C2-6	Letter dated December 22, 2016 – MoveUp Submitting Comments on Need for Oral Hearing
C2-7	Letter dated February 14, 2017 – MoveUp Submitting Regulatory Timetable Comments
C3-1	**THE BRITISH COLUMBIA OLD AGE PENSIONERS ORGANIZATION *ET AL*. (BCOAPO)** Letter dated August 25, 2016 Request to Intervene by Erin Pritchard
C3-2	Letter dated September 29, 2016 - BCOAPO Submission on Mr. Bryenton's Request to Intervene
C3-3	Letter dated October 19, 2016 – BCOAPO Submitting IR No. 1 to BC Hydro
C3-4	Letter dated December 16, 2016 - BCOAPO Submitting IR No. 2 to BC Hydro

Exhibit No.	Description
C3-5	Letter dated December 22, 2016 – BCOAPO Submitting Comments on Need for Oral Hearing
C3-6	Letter dated December 22, 2016 – BCOAPO Submitting Confidential Undertakings
C3-7	Letter dated December 23, 2016 – BCOAPO Submitting Confidential Undertakings
C3-8	Letter dated February 14, 2017 – BCOAPO Submitting Regulatory Timetable Comments
C3-9	Letter dated December 1, 2017 – BCOAPO Submitting Information Request on the Amended Application to BC Hydro
C4-1	**CLEAN ENERGY ASSOCIATION OF BC (CEABC)** Letter dated July 28, 2016 Request to Intervene by Paul Kariya and David Austin
C4-2	Letter dated October 19, 2016 – CEABC Submitting IR No. 1 to BC Hydro
C4-3	Letter dated December 16, 2016 - CEABC submitting IR No. 2 to BC Hydro
C4-4	Letter dated December 22, 2016 – CEABC Submitting Comments on Need for Oral Hearing
C4-5	Letter dated February 14, 2017 – CEABC Submitting Regulatory Timetable Comments
C4-6	Letter dated February 27, 2017 – CEABC Submitting Evidence
C4-7	Letter dated March 10, 2017 – CEABC submitting Information Request No. 1 to BCSEA
C4-8	Letter dated March 27, 2017 – CEABC Submitting Responses to NIARG IRs on Intervener Evidence
C4-9	Letter dated March 27, 2017 – CEABC Submitting Responses to BCSEA IRs on Intervener Evidence
C4-10	Letter dated April 24, 2017 – CEABC Submitting IR No. 3 to BC Hydro
C5-1	**MCCANDLESS, RICHARD (MCCANDLESS)** Letter dated August 15, 2016 Request to Intervene
C5-2	Letter dated October 17, 2016 – McCandless Submitting Information Request No. 1 to BC Hydro
C5-3	Letter dated December 15, 2016 - McCandless Submitting IR No. 2 to BC Hydro
C5-4	Letter dated February 14, 2017 – McCandless Submitting Regulatory Timetable Comments
C5-5	Letter dated November 20, 2017 – McCandless Submitting Comments on Proposal to Amend BC Hydro's F17-F19 Revenue Requirements Application

Exhibit No.	Description
C6-1	**PEACE RIVER REGIONAL DISTRICT (PRRD)** Letter dated August 23, 2016 Request to Intervene by Karen Goodings
C7-1	**TRANSCANADA ENERGY LTD. (TCE)** Letter dated August 25, 2016 Request to Intervene by Mark Thompson and Steven Kley
C7-2	Letter dated October 19, 2016 – TCE Late Submission of IR No. 1 to BC Hydro
C8-1	**FORTISBC ENERGY INC./FORTISBC INC. (FORTISBC)** Letter dated August 23, 2016 Request to Intervene by Diane Roy
C8-2	Letter dated October 19, 2016 – FortisBC Submitting IR No. 1 to BC Hydro
C8-3	Letter dated April 24, 2017 – FortisBC Submitting IR No. 3 to BC Hydro
C8-4	Letter dated December 1, 2017 – FortisBC Submitting Information Request on the Amended Application to BC Hydro
C9-1	**ASSOCIATION OF MAJOR POWER CUSTOMERS OF BRITISH COLUMBIA (AMPC)** Letter dated August 25, 2016 Request to Intervene by Richard Stout and Matthew Keen
C9-2	Letter dated October 19, 2016 – AMPC Submitting IR No. 1 to BC Hydro
C9-3	Letter dated December 16, 2016 – AMPC Submitting IR No. 2 to BC Hydro
C9-4	Letter dated December 22, 2016 – AMPC Submitting Comments on Need for Oral Hearing
C9-5	Letter dated February 1, 2017 – AMPC requesting extension of intervener evidence deadline
C9-6	Letter dated February 14, 2017 – AMPC Submitting Regulatory Timetable Comments
C9-7	Letter dated February 27, 2017 – AMPC Submitting Evidence
C9-8	Letter dated March 27, 2017 – AMPC response to BCUC
C9-9	Letter dated March 27, 2017 – AMPC response to BCSEA
C9-10	Letter dated March 27, 2017 – AMPC response to CEC
C9-11	Letter dated March 27, 2017 – AMPC response to NIARG
C10-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter dated August 25, 2016 Request to Intervene by David Craig and Chris Weafer
C10-2	Letter dated October 19, 2016 – CEC Submitting IR No. 1 to BC Hydro
C10-3	Letter dated November 24, 2016 - CEC Submitting response to Exhibit A-12

Exhibit No.	Description
C10-3-1	Letter dated November 24, 2016 - CEC Submitting Revised response to Exhibit A-12
C10-4	Letter dated December 16, 2016 - CEC Submitting IR No. 2 to BC Hydro
C10-5	Letter dated December 22, 2016 – CEC Submitting Confidential Undertakings
C10-6	Letter dated December 22, 2016 – CEC Submitting Comments on Need for Oral Hearing
C10-7	Letter dated February 14, 2017 – CEC Submitting Regulatory Timetable Comments
C10-8	Letter dated March 10, 2017 – CEC Information Request No. 1 to AMPC
C10-9	Letter dated March 10, 2017 – CEC Information Request No. 1 to BCSEA
C10-10	Letter dated April 24, 2017 – CEC Submitting IR No. 3 to BC Hydro
C10-11	Letter dated December 1, 2017 – CEC Submitting Information Request on the Amended Application to BC Hydro
C10-12	Letter dated December 8, 2017 – CEC Submitting Comments Regarding Timing on Filing Arguments
C11-1	**NON-INTEGRATED AREAS RATEPAYERS GROUP (NIARG)** Letter dated August 25, 2016 Request to Intervene by Fred Weisberg
C11-2	Letter dated October 19, 2016 – NIARG Submitting IR No. 1 to BC Hydro
C11-3	Letter dated November 24, 2016 - NIARG Submitting response to Exhibit A-12
C11-4	Letter dated December 16, 2016 – NIARG Submitting IR No. 2 to BC Hydro
C11-5	Letter dated December 22, 2016 – NIARG Submitting Comments on Need for Oral Hearing
C11-6	Letter dated February 14, 2017 – NIARG Submitting Regulatory Timetable Comments
C11-7	Letter dated March 10, 2017 – NIARG Information Request No. 1 to AMPC
C11-8	Letter dated March 10, 2017 – NIARG Information Request No. 1 to CEABC
C11-9	Letter dated March 10, 2017 – NIARG Information Request No. 1 to BCSEA
C11-10	Letter dated April 24, 2017 – NIARG Submitting IR No. 3 to BC Hydro
C11-11	Letter dated December 1, 2017 – NIARG Submitting Information Request on the Amended Application to BC Hydro
C12-1	**SKYWIND FOUNDATION (SWF)** Letter dated August 9, 2016 Request to Intervene by Terry Vulcano

Exhibit No.	Description
C12-2	Letter dated September 28, 2016 – SWF Submitting Information Request No. 1 to BC Hydro
C12-2-1	Letter dated September 29, 2016 – SWF submitting additional question to Information Request No. 1 to BC Hydro
C12-3	Letter dated December 1, 2016 - SWF submitting Information Request No. 2 to BC Hydro
C12-4	Letter dated February 14, 2017 – SWF submitting Comments
C13-1	**JOHANSSON, GWEN (JOHANSSON)** Letter dated August 25, 2016 Request to Intervene
C14-1	**SAVE OUR NORTHERN SENIORS (SONS)** Letter dated August 29, 2016 Request to Intervene by Jean Leahy
C15-1	**LANDALE, RICHARD (LANDALE)** Letter dated August 9, 2016 Request to Intervene by Richard Landale
C15-2	Submitted at Procedural Conference September 1, 2016 - WRITTEN SUBMISSIONS FROM MR. LANDALE
C15-3	Letter dated September 30, 2016 - Landale Submission on Mr. Bryenton's Request to Intervene
C15-4	Letter dated October 3, 2016 – Landale Submitting Information Request No. 1
C15-5	Letter dated August 9, 2016 - Landale Submitting Undertaking of Confidentiality
C15-6	Letter dated November 24, 2016 - Landale Submitting response to Exhibit A-12
C15-7	Submitted at Procedural Conference November 28, 2016 – PRESENTATION FROM MR. LANDALE
C15-8	Letter dated December 14, 2016 - Landale Submitting Comments regarding Oral Hearing Components
C15-9	Letter dated December 14, 2016 - Landale Submitting IR No. 2 to BC Hydro
C15-10	Letter dated February 14, 2017 – Landale Submitting Regulatory Timetable Comments
C15-11	Letter dated February 27, 2017 – Landale Submitting Evidence
C15-12	Letter dated March 27, 2017 – Landale Submitting Responses to IRs on Intervener Evidence
C15-13	Letter dated April 24, 2017 – Landale Submitting IR No. 3 to BC Hydro
C16-1	**LITTLE, MARGARET AND JAMES (LITTLE)** Letter dated August 9, 2016 Request to Intervene by Margaret and James Little

Exhibit No.	Description
C17-1	**ZONE II RATEPAYERS GROUP (ZONE II)** Letter dated August 29, 2016 Request to Intervene by Dawn Bursey and Linda Dong
C17-2	Letter dated October 19, 2016 – Zone II Submitting IR No. 1 to BC Hydro
C17-3	Letter dated November 25, 2016 – Zone II Submitting Intervener Information
C17-4	Letter dated December 16, 2016 - Zone II Submitting IR No. 2 to BC Hydro
C17-5	Letter dated December 22, 2016 – Zone II Submitting Comments on Need for Oral Hearing
C17-6	Letter dated February 2, 2017 - Zone II Submitting Comments regarding AMPC request for an extension of the deadline for intervener evidence Exhibit C9-5
C17-7	Letter dated February 14, 2017 – Zone II Submitting Regulatory Timetable Comments
C17-8	Letter dated February 27, 2017 – Zone II Submitting Evidence
C17-9	Letter dated March 27, 2017 – Zone II Submitting Responses to IRs on Intervener Evidence
C17-9-1	**CONFIDENTIAL** Letter dated March 27, 2017 – Zone II Submitting Confidential non-redacted Responses to IRs on Intervener Evidence
C17-10	Letter dated April 24, 2017 – Zone II Submitting IR No. 3 to BC Hydro
C17-10-1	Letter dated April 24, 2017 – Zone II Submitting IR No. 3 to BC Hydro –Replacement
C17-11	Letter dated December 1, 2017 – Zone II Submitting Information Request on the Amended Application to BC Hydro
C17-12	Letter dated December 12, 2017 – Zone II Submitting Comments Regarding Timing on Filing Arguments

INTERESTED PARTY DOCUMENTS

D-1	Bryenton, Roger (Bryenton) Letter dated June 9, 2016 – Request for Interested Party Status
D-1-1	Letter dated October 11, 2016 – Bryenton Submitting Comments
D-1-2	Letter dated October 11, 2016 – Bryenton Submitting Further Comments
D-2	**HARBOURGREENE CONSULTING INC. (HARBOURGREENE)** Letter dated July 27, 2016 – Request for Interested Party Status by Christine Gustafson
D-3	**SURPLUS ENERGY MATCH INC. (SURPLUS ENERGY)** Letter dated September 8, 2016 – Request for Interested Party Status

Exhibit No.	Description
D-4	**ACCENTURE BUSINESS SERVICES OF BRITISH COLUMBIA LIMITED PARTNERSHIP (ACCENTURE)** Letter dated May 10, 2017 - Request for Interested Party Status by Janet Clark
D-5	**MINISTRY OF ENERGY AND MINES (MEM)** Letter dated June 5, 2017 – Request for Interested Party Status by Jack Buchanan

LETTERS OF COMMENT

E-1	Grogan, John Letter of Comment dated June 16, 2016
E-2	Wenman, Joan Letter of Comment dated August 23, 2016
E-3	Lewko, J Letter of Comment dated April 28, 2017
E-4	Swain, H Letter of Comment dated November 20, 2017