bcuc
British Columbia
Utilities Commission

**Patrick Wruck**
Commission Secretary

Commission.Secretary@bcuc.com
**bcuc.com**

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
**P:** 604.660.4700
**TF:** 1.800.663.1385
**F:** 604.660.1102

April 23, 2019

Sent via eFile

| **BC HYDRO F2020–F2021** |
|---|
| **REVENUE REQUIREMENTS EXHIBIT A2-2** |

Mr. Fred James
Chief Regulatory Officer
Regulatory & Rates Group
British Columbia Hydro and Power Authority
16th Floor - 333 Dunsmuir Street
Vancouver, BC V6B 5R3
bchydroregulatorygroup@bchydro.com

**Re: British Columbia Hydro and Power Authority – F2020 to F2021 Revenue Requirements Application – Project No. 1598990**

Dear Mr. James:

Commission staff submit the following document for the record in this proceeding:

British Columbia Hydro and Power Authority
F2017 to F2019 Revenue Requirements Application
Order G-47-18 Compliance Filing
Dated April 27, 2018

Sincerely,

*Original Signed By:*

Patrick Wruck
Commission Secretary

/nd
Attachment

BC Hydro
Power smart

**Fred James**
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

April 27, 2018

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

**RE: Project No. 3698869**
**British Columbia Utilities Commission (BCUC or Commission)**
**British Columbia Hydro and Power Authority (BC Hydro)**
**Fiscal 2017 to Fiscal 2019 Revenue Requirements Application**

BC Hydro writes in response to Directives 1 and 2 of the BCUC's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application decision, which directed BC Hydro to provide additional information in response to seven questions to allow the Commission to better understand the rate impact resulting from energy surpluses and the portfolio management of BC Hydro's Heritage Assets[1]. The Commission also requested that BC Hydro explain the accounting treatment of surplus energy costs and recoveries[2]. This Compliance Filing provides some context regarding the Heritage Contract framework, briefly addresses four concerns that the Commission noted in its decision regarding Cost of Energy, and then addresses each of the seven questions that flowed from those concerns.

## Background – Heritage Contract Framework

All seven questions relate to "Heritage Energy"[3] and, by extension, the Heritage Contract[4] framework. In this section, we provide the historical context for the Heritage

1 "Heritage Assets" refers to the hydroelectric and thermal generation facilities outlined on page 14 of the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application Decision, together with the related civil works and plant, and, potential future investments that increase the capacity, energy or ancillary service capability of such facilities. Some of BC Hydro's Heritage Assets, such as the Fort Nelson Thermal Generating Station, provide generation to non-integrated areas.

2 BC Hydro's response uses the term recoveries consistent with the terminology in the Commission's Decision; however for accounting purposes, BC Hydro classifies the proceeds from the sale of surplus energy as revenues.

3 "Heritage Energy" refers to the definition of "Heritage Energy" as defined in the Heritage Contract (49,000 GWh per year less the energy generated for delivery under the Skagit

Contract framework and terminology. As explained below, some of the provisions and language in the framework are artifacts of how the Heritage Contract process unfolded and have no practical impact on BC Hydro's planning, operations or cost of energy today.

The Heritage Contract framework arose from the 2002 Energy Plan which, among other things, proposed the division of BC Hydro into three distinct functional entities: generation, transmission and distribution.

Policy Action No. 1 of the 2002 Energy Plan referred to a legislated heritage contract that would be similar to an arrangement that had been put in place in Quebec for Hydro-Quebec[5]. The essence of the Hydro-Quebec model was that the generation unit of Hydro-Quebec would be unregulated, but would be obliged to make available to the distribution unit of Hydro-Quebec, for sale to its ratepayers, a fixed quantity of low-embedded cost energy, at a fixed price. Any additional sales of energy by the generation unit of Hydro-Quebec would be at market prices, whether to the distribution unit of Hydro-Quebec, which would have to compete with other potential buyers, or into export markets.

The 2002 Energy Plan required BC Hydro to make a proposal to the Commission regarding a BC "heritage contract", which BC Hydro submitted in April 2003. In developing its proposal, BC Hydro gave due consideration to a fixed quantity / fixed price contract, similar to the Hydro-Quebec model, and concluded that it would not be in the interests of BC Hydro ratepayers. Among other things, BC Hydro concluded that the fixed quantity / fixed price model would have required a risk premium to be built into the price (to account for the possibility of low-stream flow years) and would have required both the generation and distribution units of BC Hydro to engage in energy markets, with competing objectives, creating redundancies and incremental costs. To avoid this outcome, BC Hydro proposed a heritage contract model that was quite different from the Hydro Quebec fixed-price, fixed quantity model.

In summary, BC Hydro's "heritage contract" proposal was that all of the actual costs of energy, as incurred by BC Hydro, should be reflected in revenue requirements with no deregulation of the generation business unit. Powerex would continue to be the sole point of access to wholesale markets for both purchases and sales. Cost of energy volatility, including trade revenue volatility, and risk, would be mitigated through the use of what was later called the "cost of energy deferral accounts". Under this framework, the interests of the generation and distribution arms of BC Hydro, and Powerex, would be aligned.

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Valley Treaty, or, the quantity of energy determined by the Commission under section 8 of the Heritage Contract to be heritage energy).

4 "Heritage Contract" refers to the Heritage Contract that is provided as Appendix A to Direction No. 7.

5 2002 Energy Plan: Energy for our Future, A Plan for BC, Page 26.

In the ensuing Commission proceeding, BC Hydro's proposal was referred to as the Revenue Requirements Model, reflecting that it was, in most consequential ways, a traditional revenue requirement approach. A counter-proposal was advanced by one intervener, and it was referred to as the Fixed Price / Fixed Quantity Model. As the name suggests, it was very much like the Hydro Quebec model that was referred to in the 2002 Energy Plan.

The two approaches were the subject of a public hearing, with oral testimony, information requests, and argument. In the end, all interveners representing customers supported BC Hydro's Revenue Requirements Model. The Commission recommended it to government, with some modifications.

The language in Direction No. 7 regarding Heritage Energy originated with the recommendations and proposed "heritage contract" prepared by the Commission for consideration by government. In order to preserve government's ability to accept or reject the Revenue Requirement Model approach, the Commission included proposed heritage contract and special direction language that would have facilitated either the Revenue Requirement Model approach or the Fixed Price / Fixed Quantity Model approach. In particular, quantities of energy were defined (Heritage Energy) and quasi-contractual arrangements were proposed (i.e., the Heritage Contract) that would have enabled an approach similar to the one foreshadowed in the 2002 Energy Plan.

Ultimately, the result of the process initiated by the 2002 Energy Plan was quite different than originally envisioned. BC Hydro is not divided into distinct functional entities and the Commission's recommendation of a Revenue Requirements Model, rather than a Fixed Price / Fixed Quantity Model (akin to Hydro-Quebec's approach), was accepted by government with some additional modifications.

Government issued Heritage Special Direction No. HC2 to give effect to the accepted model, with the language that would have enabled the Fixed Price / Fixed Quantity approach included, as an artifact of how the process unfolded.

Today, that language has continued into Direction No. 7[6] even though much of the terminology and the concept of a fixed quantity of heritage energy have no bearing on how BC Hydro's cost of energy is actually determined.

## Definition of "Heritage Energy" – No Impacts on Planning, Operations or Ratepayers

The definition of "Heritage Energy" has no practical implications for the way in which BC Hydro's system is planned or operated, or the rates paid by BC Hydro's customers. The same is true for section 5(b) of Direction No. 7, which states that "[i]n setting the

6 Order in Council 97 (March 5, 2014) repealed Heritage Special Direction No. HC2 and approved Direction No. 7.

authority's rates, the commission… 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." Before explaining why this is the case, we wish to clarify how "energy supplied' should be interpreted under this section.

In Table 3-5, the Commission estimated the amount of energy that is required in excess of the energy supplied under the Heritage Contract, based on the definition of Heritage Energy contained in the Heritage Contract. However, Section 5(b) refers to "energy supplied under the heritage contract", which is different from "Heritage Energy" (a defined term used elsewhere in Direction No. 7).

The 2002 Energy Plan indicated that the quantity of energy (Heritage Energy) included in the Heritage Contract would be based on the production of the Heritage Resources under average water conditions. To develop the quantity of energy for the Heritage Contract, BC Hydro examined the historical average energy from the Heritage Resources and simulation studies of expected future generation from these resources. Based on this analysis, BC Hydro recommended that the Heritage Contract provide for a maximum energy supply obligation of 49,000 GWh per year.[7] As noted in the Commission's 2003 Report and Recommendations, this amount was illustrative and meant to represent the maximum reliable capability of Heritage Resources, not the expected or supplied amount from year to year[8].

BC Hydro also clarifies that the total Heritage Energy shown in Table 3-3 of the Commission's decision accompanying Order No. G-47-18 is not equivalent to the forecast energy supplied from Heritage Assets. The amount in Table 3-3 reflects the calculation of the heritage payment obligation as set out in Appendix A of Direction No. 7, including the subtraction of revenues from surplus sales under the Transfer Pricing Agreement. However, BC Hydro does not deduct surplus sales from the energy supplied by Heritage Assets. Rather, revenues from surplus sales are netted against the total costs of supply, both Heritage and Non-Heritage, to arrive at the total cost of energy.

As mentioned above, the definition of "Heritage Energy" has no practical implications for how BC Hydro's system is planned or operated. BC Hydro does not use the definition of Heritage Energy to determine its forecast supply from current and planned resources, and by extension, does not rely on the definition of Heritage Energy to determine when new energy supply resources are required. Rather, BC Hydro uses the planning criteria as defined in Special Direction 10, which states that BC Hydro must be self-sufficient, assuming no more in each year than the firm energy capability from hydroelectric facilities. Firm energy capability is defined as the maximum amount of annual energy

7 An Inquiry Into A Heritage Contract for British Columbia Hydro and Power Authority's Existing Generation Resources and Regarding Stepped Rates and Transmission Access, Exhibit 8, p. 19.

8 An Inquiry Into A Heritage Contract for British Columbia Hydro and Power Authority's Existing Generating Resources and Regarding Stepped Rates and Transmission Access, Report and Recommendations, p. 16-17.

that a hydroelectric system can produce under average water conditions and BC Hydro updates this value from time to time when determining whether new energy supply resources are required.

The definition of Heritage Energy also does not influence how BC Hydro operates its system. BC Hydro uses its energy study models to inform operational decisions on system storage operations, thermal dispatch and purchases and sales of market electricity in order to maximize consolidated net revenue while satisfying domestic integrated system requirements and contractual obligations.

Energy study models are also used by BC Hydro for the ongoing financial forecasting of the Cost of Energy, which is used in revenue requirements proceedings to set rates. In this regard, the definition of Heritage Energy only influences the calculation of actual Heritage Energy costs, which impacts how costs are allocated to the Heritage and Non-Heritage energy deferral accounts. Those accounts are prescribed by Direction No. 7. Ultimately, this allocation between the accounts has no impact on ratepayers as the recovery mechanism for the heritage and non-heritage deferral accounts is the same.

It is for these reasons that BC Hydro stated during the Fiscal 2012 to Fiscal 2014 Revenue Requirements Application that, all else being equal, an increase or decrease in the definition of Heritage Energy would result in no change in BC Hydro's revenue requirements because BC Hydro is obligated to serve all domestic load, including any load requirements in excess of Heritage Energy.[9]

**Response to Commission Concerns with Forecast Cost of Energy**

In its decision accompanying Order No. G-47-18, the Commission raised four concerns regarding the forecast cost of energy as context for the questions addressed in this compliance filing. Those concerns (reordered) were:

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

Our answer to question 1 below explains how to reconcile the Heritage Energy forecast in the Load Resource Balance and the forecast in Table 4 of Appendix A and our

9 BCOAPO IR 1.28.2 from Fiscal 2012 to Fiscal 2014 Revenue Requirements Application.

answer to question 4 below explains our accounting treatment of surplus energy costs and recoveries.

With regards to the Commission's concern that Heritage Assets may not be providing optimal value to BC Hydro customers as anticipated in the Heritage Contract, BC Hydro believes that the above history on the Heritage Contract and the definition of Heritage Energy provides helpful context. As the generation, transmission and distribution functions of BC Hydro are not separated and as ratepayers must pay the actual costs of all energy supplied, including energy supplied from Heritage Assets and from energy purchase agreements, it is in the best interests of ratepayers for BC Hydro to optimize all sources of supply as part of a single portfolio. As explained during the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application proceeding, this means that BC Hydro maximizes its consolidated net revenue from operations rather than optimizing the amount of Heritage Energy[10]. Managing BC Hydro's portfolio of assets based on distinctions between Heritage and Non-Heritage Energy would result in higher costs to customers.

With regards to the Commission's concern around the cost of IPPs and Long-Term Commitments included in BC Hydro's Cost of Energy, as discussed during the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application proceeding, BC Hydro takes a long-term view of cost effectiveness[11] and with that there is an inherent trade-off between short-term costs and anticipated longer-term savings and security of supply. We believe that the appropriate forum for these considerations continues to be the review process under Section 71 of the *Utilities Commission Act* as well as the Integrated Resource Planning process.

The remainder of this filing provides BC Hydro's answers to the Commission's seven questions.

**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.**

### Reconciliation of Schedule 4 and Table 3-8

Table 3-8 in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (Exhibit B-1-1) was resubmitted by BC Hydro as part of our response to BCUC IR 1.11.1 which included some minor corrections; however, these corrections did not change the values shown in Line (a) for "Heritage Resources (including Site C)". For ease of reference, we have reproduced the corrected Table 3-8 below.

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[10] BCUC IR 1.15.1.2.

[11] BCUC IR 1.15.2.

Table 3-8 is based on BC Hydro's load-resource balance. In Table 3-8, Line (a), "Heritage Resources (including Site C)" reflects BC Hydro's hydroelectric and thermal resources (including Waneta) and transfers of energy (defined as "Exchange Net" and as more fully explained in our response to question 4 to this submission). The value shown in this line only includes heritage energy from the integrated system (i.e., excludes Fort Nelson which is in a non-integrated area).

**Table 3-8 Energy Load Resource Balance after Planned Resources**

| | (GWh) | | F2017 | F2018 | F2019 | F2020 | F2021 | F2022 | F2023 | F2024 | F2025 | F2026 | F2027 | F2028 | F2029 | F2030 | F2031 | F2032 | F2033 | F2034 | F2035 | F2036 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ***Existing and Committed Heritage Resources*** | | | | | | | | | | | | | | | | | | | | | |
| 1 | Heritage Resources (including Site C) | (a) | 48,445 | 46,895 | 46,014 | 48,491 | 48,491 | 48,491 | 48,491 | 48,857 | 52,383 | 53,777 | 53,777 | 53,777 | 53,777 | 53,777 | 53,777 | 53,777 | 53,777 | 53,777 | 53,777 | 53,777 |
| 2 | ***Existing and Committed IPP Resources*** | (b) | 13,198 | 14,592 | 14,337 | 14,364 | 14,097 | 13,782 | 13,547 | 13,210 | 12,814 | 12,414 | 12,307 | 11,983 | 11,467 | 10,720 | 10,259 | 10,203 | 10,163 | 10,015 | 9,476 | 8,110 |
| | ***Future Supply-Side Resources*** | | | | | | | | | | | | | | | | | | | | | |
| 3 | IPP Renewals | | 106 | 280 | 571 | 647 | 779 | 936 | 1,114 | 1,349 | 1,628 | 1,951 | 2,032 | 2,223 | 2,617 | 3,328 | 3,788 | 3,828 | 3,863 | 4,011 | 4,549 | 5,515 |
| 4 | Standing Offer Program | | 71 | 130 | 291 | 419 | 546 | 674 | 801 | 929 | 1,056 | 1,184 | 1,311 | 1,439 | 1,566 | 1,694 | 1,821 | 1,949 | 2,076 | 2,204 | 2,320 | 2,448 |
| 5 | Revelstoke 6 | | | | | | | | | | | | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 |
| 6 | Sub-total | (c) | 177 | 410 | 862 | 1,066 | 1,325 | 1,609 | 1,916 | 2,278 | 2,684 | 3,135 | 3,370 | 3,688 | 4,209 | 5,048 | 5,635 | 5,803 | 5,966 | 6,241 | 6,895 | 7,988 |
| 7 | **Total Supply (Operational View) **** | (d) = a + b + c | 61,820 | 61,897 | 61,213 | 63,922 | 63,913 | 63,883 | 63,954 | 64,345 | 67,881 | 69,327 | 69,454 | 69,449 | 69,453 | 69,545 | 69,672 | 69,783 | 69,906 | 70,033 | 70,149 | 69,875 |
| | ***Demand - Integrated System Total Gross Requirements*** | | | | | | | | | | | | | | | | | | | | | |
| 8 | 2016 May Mid Load Forecast Before DSM* | | -58,334 | -59,013 | -60,413 | -61,371 | -62,309 | -63,675 | -64,836 | -66,008 | -67,109 | -68,310 | -69,267 | -70,256 | -71,222 | -72,296 | -73,374 | -74,535 | -75,462 | -76,393 | -77,215 | -78,089 |
| 9 | Expected LNG Load | | -61 | -148 | -148 | -252 | -1,265 | -2,299 | -2,721 | -2,848 | -2,848 | -2,848 | -2,848 | -2,848 | -2,848 | -2,848 | -2,848 | -2,848 | -2,848 | -2,848 | -2,848 | -2,848 |
| 10 | Sub-total | (e) | -58,395 | -59,162 | -60,561 | -61,624 | -63,574 | -65,974 | -67,557 | -68,856 | -69,957 | -71,158 | -72,115 | -73,104 | -74,070 | -75,144 | -76,222 | -77,383 | -78,310 | -79,241 | -80,063 | -80,937 |
| | ***Existing and Committed Demand Side Management & Others Measures*** | | | | | | | | | | | | | | | | | | | | | |
| 11 | SMI Theft Reduction | | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 |
| 12 | Voltage and VAR Optimization | | 67 | 152 | 171 | 188 | 219 | 240 | 254 | 259 | 263 | 268 | 285 | 290 | 295 | 300 | 305 | 310 | 315 | 320 | 325 | 331 |
| 13 | 2016 DSM Plan F16 savings | | 982 | 970 | 939 | 940 | 935 | 926 | 923 | 917 | 912 | 885 | 863 | 855 | 848 | 844 | 807 | 770 | 760 | 758 | 757 | 736 |
| | ***Planned Demand Side Management Measures*** | | | | | | | | | | | | | | | | | | | | | |
| 14 | 2016 DSM Plan F17 to F19 savings | | 389 | 988 | 1,679 | 1,896 | 1,931 | 1,969 | 1,956 | 1,935 | 1,917 | 1,908 | 1,896 | 1,853 | 1,787 | 1,694 | 1,613 | 1,547 | 1,462 | 1,300 | 1,224 | 1,190 |
| 15 | 2016 DSM Plan F20+ savings | | 0 | 0 | 0 | 292 | 904 | 1,454 | 1,897 | 2,310 | 2,637 | 2,946 | 3,229 | 3,500 | 3,758 | 4,006 | 4,248 | 4,473 | 4,690 | 4,908 | 5,116 | 4,976 |
| 16 | Sub-total | (f) | 1,521 | 2,192 | 2,873 | 3,399 | 4,072 | 4,672 | 5,112 | 5,502 | 5,811 | 6,089 | 6,356 | 6,581 | 6,770 | 6,927 | 7,055 | 7,183 | 7,310 | 7,368 | 7,505 | 7,317 |
| | | | **F2017** | **F2018** | **F2019** | **F2020** | **F2021** | **F2022** | **F2023** | **F2024** | **F2025** | **F2026** | **F2027** | **F2028** | **F2029** | **F2030** | **F2031** | **F2032** | **F2033** | **F2034** | **F2035** | **F2036** |
| 17 | **Surplus / (Deficit) (Operational View) **** | (g) = d + e + f | **4,945** | **4,928** | **3,524** | **5,697** | **4,411** | **2,582** | **1,509** | **991** | **3,735** | **4,257** | **3,695** | **2,926** | **2,154** | **1,328** | **506** | **(417)** | **(1,093)** | **(1,840)** | **(2,410)** | **(3,745)** |
| 18 | **Surplus / Deficit as % of Net Load (Planning View) **** | | **113%** | **115%** | **115%** | **114%** | **111%** | **108%** | **106%** | **105%** | **109%** | **110%** | **109%** | **107%** | **106%** | **105%** | **103%** | **102%** | **101%** | **99.97%** | **99%** | **97%** |
| 19 | Small Gap Surplus/(Deficit) (Operational View) ** | | 7,266 | 7,487 | 6,536 | 9,087 | 8,279 | 6,967 | 6,275 | 6,030 | 9,076 | 9,893 | 9,540 | 9,017 | 8,506 | 7,946 | 7,350 | 6,766 | 6,346 | 5,779 | 5,262 | 4,056 |
| 20 | Large Gap Surplus/(Deficit) (Operational View) ** | | 2,559 | 2,036 | *(70)* | 1,293 | *(601)* | *(3,171)* | *(5,130)* | *(6,012)* | *(3,641)* | *(3,506)* | *(4,231)* | *(5,328)* | *(6,482)* | *(7,776)* | *(8,872)* | *(10,089)* | *(11,032)* | *(12,060)* | *(13,047)* | *(14,732)* |

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

Schedule 4.0 of Appendix A (Exhibit B-1-1) includes heritage energy from both the integrated system and non-integrated system. Accordingly, Line 5 ("Natural Gas for Thermal Generation") includes forecasts for Prince Rupert and Fort Nelson. Historically, this line item also included Burrard. BC Hydro notes that thermal generation for Prince Rupert is forecast to be zero in fiscal 2018 and beyond. Accordingly, going forward Line 5 only reflects Fort Nelson forecasts.

Although Waneta is included under the heading "Non-Heritage Energy" in Schedule 4.0, BC Hydro's interest in Waneta is a heritage asset as defined in the *Clean Energy Act* and, as such, is considered a heritage resource from a planning and operational perspective.

As Schedule 4 includes heritage energy from Non-Integrated Areas (i.e., Fort Nelson) and Table 3-8 only includes heritage energy from the integrated system, certain steps are required to reconcile Appendix A, Schedule 4 and Table 3-8.

Line (a) of Table 3-8 is derived by summing the following from Schedule 4.0 of Appendix A (Exhibit B-1-1):

- Line 1 ("Hydroelectric (water rentals)"); plus
- That portion of Line 5 ("Natural Gas for Thermal Generation") attributed to resources on the integrated system which for fiscal 2018 and beyond has a value of zero[12]; plus
- Line 7 ("Exchange Net"); plus
- Line 9 ("Waneta (water rentals)").

Accordingly, as shown in the schedule below, for fiscal 2017 to fiscal 2019, the sum of Lines 1, 7 and 9 equals the energy from hydroelectric and thermal heritage resources on the integrated system.

The schedule below also provides the "actual Heritage Energy" delivered to BC Hydro in each of the last 10 years.[13].

**Appendix A (Excel Version), Schedule 4.0, Cost of Energy (fiscal 2007-fiscal 2019)**

| Sources of Supply (GWh) | | F2007 | F2008 | F2009 | F2010 | F2011 | F2012 | F2013 | F2014 | F2015 | F2016 | F2017 | F2018 | F2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Plan | Plan | Plan |
| 1 | Hydroelectric (water rentals) | 44,476 | 52,140 | 43,812 | 43,137 | 38,295 | 48,821 | 51,107 | 44,437 | 40,191 | 48,945 | 47,985 | 46,626 | 45,781 |
| 7 | Exchange Net | 410 | (485) | 536 | (1,092) | 372 | (45) | 28 | (103) | 88 | (976) | (115) | (323) | (354) |
| 9 | Waneta (water rentals) | 0 | 0 | 0 | 71 | 1,008 | 1,008 | 1,008 | 891 | 1,038 | 407 | 575 | 593 | 587 |
| | | 44,886 | 51,655 | 44,348 | 42,116 | 39,675 | 49,784 | 52,143 | 45,225 | 41,318 | 48,376 | 48,445 | 46,895 | 46,014 |
| 5 | Natural Gas for Thermal Generation | 847 | 423 | 312 | 400 | 251 | 143 | 122 | 268 | 213 | 215 | 224 | 232 | 234 |
| | Total Heritage Resources | 45,733 | 52,078 | 44,660 | 42,516 | 39,926 | 49,927 | 52,265 | 45,493 | 41,531 | 48,591 | 48,669 | 47,127 | 46,248 |

**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.**

The table below provides a breakdown of Line 2 of Schedule 4.0, of Appendix A for the fiscal 2017 to fiscal 2019 period. A description of Line 2 is more fully explained in our response to question 4 to this Compliance Filing.

12 For fiscal 2017, for the integrated system, there is a small amount of energy (approximately 1 GWh) attributed to Prince Rupert which was not fully captured in Table 3-8, but which is included in Line 5 of Schedule 4.0.

13 The historical information included in this schedule is sourced from the Excel version of the Financial Schedules of Appendix A of BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (Exhibit B-1-1). Please refer to Schedule 4.0 of Appendix A (Excel version) by using the "unhide" function for viewing.

| | | | | | |
|---|---|---|---|---|---|
| **Appendix A, Schedule 4.0** | | | | | |
| **Cost of Energy** | | | | | |
| | **Sources of Supply (GWh)** | | **F2017** | **F2018** | **F2019** |
| | **Line** | | **Plan** | **Plan** | **Plan** |
| | | **Heritage Energy** | | | |
| | 2 | Net Purchases (Sales) from Powerex | **(267)** | **(253)** | **105** |
| | | | | | |
| | | | | | |
| **Breakdown into gross volumes:** | | | | | |
| | | Purchases from Powerex | **628** | **732** | **1,223** |
| | | Sales to Powerex | **(895)** | **(986)** | **(1,118)** |
| | | | **(267)** | **(253)** | **105** |

**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.**

Below is a description of each of the line items listed under the heading "Heritage Energy" of Schedule 4.0 of Appendix A of the Application. Please also refer to Section 4.4.1 (pages 4-10 through 4-15) of the Application (Exhibit B-1-1) for additional information.

***Line 1 (and Line 26) – Hydroelectric (Water Rentals)***

This category includes water rental fees for hydroelectric facilities, payable to the Province, which are calculated as the actual energy output of the license holder from the prior calendar year times the current year rates. These fees are broken down into the following components:

- Generation output;
- Operating capacity
- Construction capacity; and
- Other miscellaneous license costs.

There are also annual adjustments which include energy and capacity exemptions under the Skagit Valley Treaty and energy transfers under the Columbia River Treaty related agreements. As noted in response to question 1 above, water rentals related to BC Hydro's interest in Waneta are not included in this category in Schedule 4.0, as Waneta is not included in the definition of Heritage Energy. As such, Waneta water rentals are included on Line 9 of Schedule 4.0.

### *Line 2 – Net Purchases / (Sales) from Powerex*

This category includes:

Sales to Powerex: Under the Transfer Pricing Agreement (**TPA**), Powerex may elect to purchase energy from BC Hydro when the BC Hydro system has flexibility to draft from system storage, and withdraw the amount from the Trade Account.

Purchases from Powerex: Similarly, under the TPA, Powerex may elect to sell energy to BC Hydro, again when the BC Hydro system has flexibility to store that energy, and deposit the amount in the Trade Account.

These net transfers to or from the Trade Account are shown as Net Purchases (Sales) from Powerex.

### *Line 3 (and Line 27) – Market Electricity Purchases*

This category includes market purchases of electricity by BC Hydro to meet its load requirements. These transactions are performed exclusively with Powerex. BC Hydro specifies the transfer price and/or volume as governed by the TPA. Energy deliveries to Seattle City Light under the Skagit Valley Treaty are also considered part of BC Hydro's system load, and under the TPA, Powerex has the option to source these energy deliveries from Mid-C when economic to do so, and these energy deliveries are accounted for as BC Hydro market electricity purchases.

### *Lines 4 (and Line 28) – Market Purchases to Non-Heritage*

As provided in Direction No. 7, market electricity purchases allocated to Heritage Energy are capped to maintain the volume of energy provided under the Heritage Contract at no more than 49,000 GWh/year. Any market electricity purchases which would exceed 49,000 GWh/year would be included in Non-Heritage Energy. There are no forecast market purchases allocated to Non-Heritage Energy.

### *Lines 5 (and Line 29) – Natural Gas for Thermal Generation*

This category includes thermal generation for Prince Rupert and Fort Nelson (and historically for Burrard) and the costs associated with running these generation stations. Costs include natural gas, gas transportation, taxes (carbon, motor fuel) and chemical costs. Please also refer to Table 4-5 of the Application.

### *Line 6 (and Line 32) – Surplus Sales*

Surplus Sales are sales of electricity when BC Hydro has energy that is surplus to load requirements. Transactions are performed exclusively with Powerex.

***Line 7 – Exchange Net***

Exchange Net primarily includes transfers of energy that are related to BC Hydro's entitlement obligations under the Canal Plant and Keenleyside Entitlement Agreements. These energy transfers are not executed at market prices, but may result in reimbursement or payment of water rental fees. The financial impact of such reimbursements and payments are recorded with "water rentals". For reporting of actuals, Exchange Net is also used to reconcile total sources of supply recorded for financial statement purposes to the actual load recorded on the BC Hydro load report.

***Line 30 – Domestic Transmission***

This category includes transmission costs associated with Surplus Sales (exports to U.S. and Alberta) and transmission costs relating to BC Hydro's obligations under the Skagit Valley Treaty.

***Line 31 – Columbia River Treaty Related Agreements***

This category includes costs or recoveries associated with transactions related to the Non-Treaty Storage Agreement (**NTSA**) and the Libby Coordination Agreement. The NTSA is an agreement between BC Hydro and the Bonneville Power Administration (**BPA**) to operate non-treaty storage at Kinbasket Reservoir. The Libby Coordination Agreement is a supplemental agreement to the Columbia River Treaty and is with both the BPA and the U.S. Army Corps of Engineers. This agreement and its operations are similar to the NTSA.

While the NTSA has the option to receive an energy delivery from the U.S. to the B.C. Border, in lieu of a financial payment, in recent years only financial settlements have occurred, so only a financial line item is included. The Libby Coordination Agreement activities are currently only financial transactions.

***Line 33 – Remissions and Other***

The *Water Sustainability Act* specifies Remissions that are available to be applied against the water rental payments. These Remissions are compensation due to restrictions or regulations imposed on the licensee. The annual remissions cap is $50 million per calendar year, with any owed excess by the Province carried into future years.

**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;**

**An explanation of the accounting treatment of surplus energy cost and recoveries including how recoveries are calculated and recorded, the treatment of costs for under-utilized assets and/or any take or pay**

**arrangement that exists with IPPs, and any other relevant details to describe how costs resulting from surplus energy are offset by recoveries for that energy;**

**To demonstrate how these policies are applied to BC Hydro's accounts, include an analysis, for the last 5 years that quantifies the value of actual surplus energy purchased above domestic consumption.**

As explained during the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application[14], section 6 of the *Clean Energy Act* and the *Electricity Self Sufficiency Regulation* require BC Hydro to acquire resources (e.g., contracts with IPPs) to meet our obligation to be self-sufficient based on average water conditions from our heritage resources and our mid-load forecast.

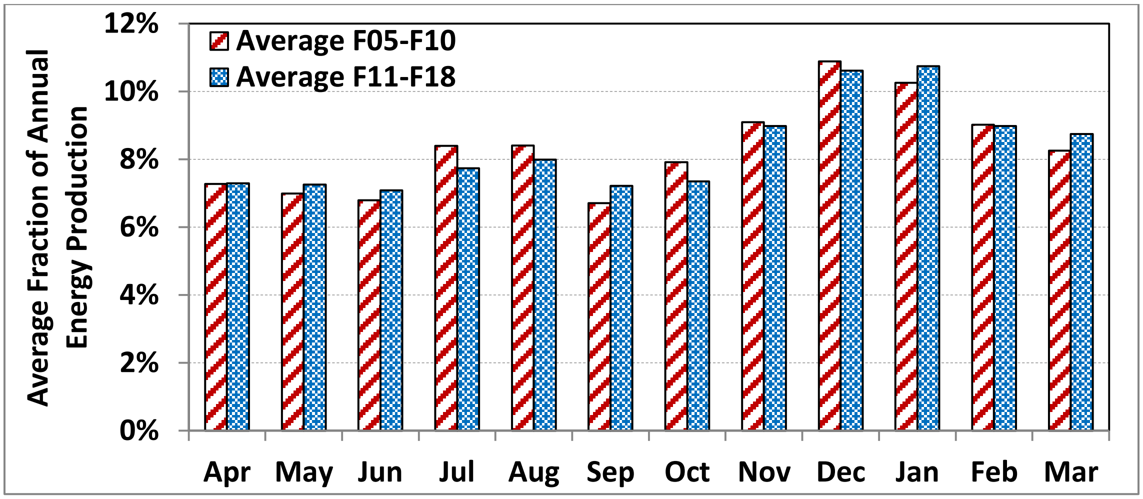
Planning to average expected conditions will result in operating years in which BC Hydro has net surplus sales or net market purchases depending on a number of factors including actual customer loads, market prices and system conditions and constraints. Once acquired, BC Hydro and/or Powerex optimize the purchase and sale of electricity and natural gas given BC Hydro's capabilities and domestic requirements. One of the key variables in our system is the contribution from BC Hydro's hydroelectric resources which, in the past 10 years, has had a difference of 12,000 GWh between low and high water years, requiring surplus sales or market purchases.

The energy supplied by IPPs has not had a material impact on how BC Hydro operates its integrated Heritage Assets on an annual basis.

BC Hydro has been operating under a net surplus (long) position under average inflows since approximately fiscal 2011, although in any given year we can still have an annual net deficit (short) position under observed inflows as occurred in fiscal 2014. The figure below demonstrates that the overall operation of the heritage hydro generation has not changed significantly between the period when BC Hydro was net short under average inflows (fiscal 2005 to fiscal 2010) and when it was net long under average inflows (fiscal 2011 to fiscal 2018). The data in the figure is represented as a percentage of normalized annual heritage hydro generation during each period.

[14] MoveUp IR 1.14.1.

**Annual Profile of Total Heritage Hydro Generation by Month**




Large reservoir storage resources – like BC Hydro's heritage hydro assets – are highly flexible and can be made available in seconds. This provides tremendous value to our customers by helping to integrate intermittent IPP resources (e.g., wind, solar), which have highly variable output, and by taking advantage of external markets when prices are highest.

We have observed that the primary impact of operating under a net surplus position has been on BC Hydro/Powerex's market energy purchases and sales. Energy supplied by some IPPs has exacerbated the seasonal imbalance of load and resources during the spring freshet, a period when there is a significant inflow into BC Hydro's reservoirs due to snowmelt. During the freshet period, system loads are relatively low due to warmer temperatures and market prices are low due to overall supply.

This increased IPP generation during the freshet has led to an increased number of hours where minimum generation levels exceed domestic load, resulting in forced exports (when BC Hydro must generate more energy than it needs and is forced to sell the excess to the market at the going market price)[15]. This imbalance has also reduced our ability to take low cost market imports into the system.

In addition, our flexible heritage hydro assets are required to fill the gaps when intermittent IPP resources drop off (e.g., when the wind stops blowing or the sun goes down). The variability in these intermittent resources – both the sudden surges and sudden drops in output – otherwise creates significant reliability issues for the system. However, using our heritage hydro assets to fill the periods when intermittent resources

15 Preliminary Evaluation Report Year 1 – Transmission Service Freshet Rate – Appendix D, Page 3-5 and BCUC IR 1.15.3

are not available limits the use of this flexibility for other, higher value, purposes such as taking advantage of high prices in external markets.

BC Hydro notes that while the additional generation from contracted IPP facilities over the last 15 years has resulted in additional supply capability, our accounting treatment does not attribute surplus or deficit energy to any particular set of loads or resources because the system is managed as a whole to maximize the consolidated net revenue from operations. The operation of the integrated BC Hydro system is optimized given the portfolio of available resources (heritage resources, IPP resources and/or market sales and purchases) and loads under the observed and forecast weather, inflow, and market price conditions. The result is that surpluses are managed by a combination of market electricity sales, system storage deposits, and spills; while deficits are managed by a combination of market electricity purchases, system storage withdrawals, and thermal generation. Accordingly, we have not provided the annual analysis of surplus costs and recoveries as requested by the Commission[16]. Providing this analysis would require a counterfactual set of assumptions (e.g., the quantity of IPPs that would not have been acquired) which would have to then be modeled as a re-optimized portfolio and would be of limited value since operational decisions would likely have been different than the ones taken if the circumstances were changed.

We also note that revenues from surplus sales (Line 32 of Schedule 4.0 in Appendix A) are netted against the total costs of supply to arrive at the total cost of energy (Line 44 of Schedule 4.0 in Appendix A).

**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.**

As explained in footnote 43 on Page 3-27 of the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-8 provides the forecast operation of BC Hydro's Existing and Committed Heritage Resources given near term reservoir elevations and expected water conditions (from the Energy Study) for fiscal 2017 to fiscal 2019 and assuming average water conditions for fiscal 2020 and beyond. Line (a) of Table 3-8 of the Application (i.e., "Heritage Resources (including Site C)") is replicated in Row 1 of Table 1 below for fiscal 2017 to fiscal 2022.

To clarify this explanation, the values provided for fiscal 2017 to fiscal 2019 were based on the forecast from the May 2016 Energy Study which was performed with an <u>objective to maximize economic value</u> whereas the values shown for 2020 and beyond reflect energy capability estimated based on a study that models the system with an <u>objective to maximize energy production</u> assuming long-term average conditions. Both of these

16 In BC Hydro's response to CEC IR 2.145.1 we declined to provide a similar analysis as it would have implied that forecast excess energy (above forecast load) is directly attributable to BC Hydro energy purchases from IPPs under Electricity Purchase Agreements.

modeling exercises provide estimates of the energy production but their objectives are different. Accordingly, the results will be different.

Energy Studies are performed by BC Hydro on a monthly basis, and are based on current conditions (i.e., market forecasts, reservoir elevations, inflow forecasts and near-term operational constraints). A detailed description of the Energy Study models was provided during the Fiscal 2017 to Fiscal 2019 Revenue Requirements proceeding[17].

Row 2 of Table 1 below shows the updated Energy Study modeling values as of October 2017 for five years (fiscal 2018-fiscal 2022). These October 2017 forecasts are the values which were used in our most recent Service Plan.

**Table 1 Existing and Committed Heritage Resources**

| Row | Heritage Resources (GWh) | Fiscal 2017 | Fiscal 2018 | Fiscal 2019 | Fiscal 2020 | Fiscal 2021 | Fiscal 2022 | Average (F18-F22)[18] |
|---|---|---|---|---|---|---|---|---|
| 1 | Line (a) Table 3-8 (as of RRA filing) | 48,445 | 46,895 | 46,014 | 48,491 | 48,491 | 48,491 | |
| 2 | Forecast using Energy Studies Modeling (as of October 2017)[19] | n/a | 47,226 | 45,794 | 45,090 | 45,908 | 46,653 | 46,134 |

Table 2 below provides actual historical deliveries of Heritage Energy for the integrated system and non-integrated system by year for fiscal 2007 to fiscal 2017.[20] The average Heritage Energy delivered in this 10-year period was 46,480 GWh, and ranged from a low of 39,926 GWh to a high of 52,265 GWh. The large variability in year to year values is primarily due to water variability, and to some extent due to market conditions.

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17 BCUC IR 1.15.1

18 An average for Line 1 is not provided as Line 1 because, as explained above, this line provides values based on one methodology for fiscal 2017 to fiscal 2019 and a different methodology for fiscal 2020 and beyond.

19 Row 1 provides data for fiscal 2017, as stated in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. There is no data available for fiscal 2017 in the October 2017 Energy Study (fiscal 2018), as the Energy Study is forward looking, and fiscal 2017 was in the past when the Study was produced.

20 Please also refer to BC Hydro's response to question 1 for a more detailed breakdown of the actual historical deliveries.

**Table 2 Actual Historical Deliveries from Heritage Energy**

| Fiscal Year | Actual Heritage Energy Delivered (GWh) |
|---|---|
| 2007 | 45,733 |
| 2008 | 52,078 |
| 2009 | 44,660 |
| 2010 | 42,516 |
| 2011 | 39,926 |
| 2012 | 49,927 |
| 2013 | 52,265 |
| 2014 | 45,493 |
| 2015 | 41,531 |
| 2016 | 48,591 |
| 2017 | 48,557 |
| Average actual (2007-2017) | 46,480 |

The difference between the average of the forecasts provided in Table 1 (46,134 GWh), and the average of the historical actuals provided in Table 2 (46,480 GWh), is minimal, and accordingly, a description of these minor differences is not provided.

**vi. A thorough discussion of whether the generating abilities of any Heritage Assets have been impaired or reduced in any way.**

As discussed in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, BC Hydro's Heritage Assets are aging and reinvestment in these facilities is required to ensure customers continue to receive reliable power. Our capital plan reflects the continuing importance of reinvesting in our electric system assets for the long-term benefit of customers. BC Hydro has also made and continues to make investments to increase the capacity and energy provided by our Heritage Assets.

With respect to our response to this question, we note two points:

- BC Hydro has described changes in the capacity of the Heritage Assets. Estimates of changes in energy are also provided but these estimates are approximate and only provide an order of magnitude sense of the energy impact. Further, as the data provided is sourced from different types of studies (i.e., some are capability studies and some are economic studies), the energy values are not additive;
- The generating abilities of Heritage Assets may be impaired or reduced, from time to time, as a result of equipment condition or failure, maintenance requirements or seismic risks. As minor impairments or reductions generally do not have a significant and/or long-term impact, we have focused on substantive impairments and reductions to the generating abilities of Heritage Assets.

Our 10-year capital forecast for fiscal 2019 to fiscal 2028 (10-Year Fiscal 2019 to Fiscal 28 Capital Forecast) includes the most recent proposed projects to address most of those cases where there are substantive reductions or impairments to the generating abilities of Heritage Assets[21]. The following is a list of those projects:

- La Joie (25 MW): The reservoir level in the La Joie dam has been temporarily lowered, as an interim approach to lowering seismic risks associated with the dam. This interim measure reduces the reservoir storage volume by about one-half and limits the unit output to 22 MW (energy impact: -55 GWh). A project has been initiated to mitigate the dam safety risk, after which the full use of the reservoir volume and unit capacity will be restored;
- Clowhom (33 MW): In 2012, maximum sustainable output of Clowhom was reduced from 33 MW to 29.8 MW (no impact on energy) due to the condition of the generator winding. A project to rehabilitate the main generating equipment components at Clowhom is currently planned in the next 10 years;
- Bridge River (500 MW): Currently, five of eight generating units are de-rated due to failures and deteriorating equipment, resulting in a loss of about 20 per cent (or 100 MW) of Bridge River's capacity (energy impact: -40 GWh). Projects are underway to restore the generating abilities of the Bridge River units; and
- Alouette (9 MW): The facility has been forced out of service since 2010 due to multiple cascading equipment failures (energy impact: -55 GWh). While a project to redevelop this facility is in the 10-Year Fiscal 2019 to Fiscal 28 Capital Forecast, an update of the facility asset plan for Alouette is currently in progress which is likely to defer this project beyond fiscal 2028.

In some cases, BC Hydro has determined that a project to address a substantive reduction or impairment does not deliver sufficient benefits to be prioritized and funded over other investments at this time; accordingly, the projects listed below are not included in BC Hydro's 10 Year Fiscal 2019 to Fiscal 2028 Capital Forecast. We expect these reductions or impairments to continue until there is a system need for energy or capacity and the investments required to address these reductions or impairments will deliver sufficient benefits to be prioritized and funded in preference to other investments[22]:

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21 BC Hydro provided an updated 10 Year Capital Forecast (Appendix G) to the BCUC as part of the initial Application filing in July 2016. BC Hydro updates this forecast annually.

22 The Shuswap Falls Facility continues to generate electricity from one of two units and the remainder of the overall facility continues to be used to convey water for environmental, recreational and other purposes, consistent with the Shuswap Water Use Plan. The Alouette and Elko facilities are currently being used to convey water downstream. The Alouette Facility has a significant water management function, which benefits generation at downstream facilities (Stave River System) and provides benefits for fish, area recreation and flood mitigation. In the case of Elko facility, the short term benefit is primarily in maintaining downstream water flows at required minimum levels, which is necessary to preserve the site for the longer term.

- Shuswap Falls (6.5 MW): Due to unsatisfactory equipment condition, the 3 MW generation Unit 1 has been out of service since 2013, following a fault that damaged the generator (energy impact: -10 GWh); and
- Elko (12 MW): The generating plant has been forced out of service due to unsatisfactory equipment condition since 2014 (energy impact: -70 GWh).

In addition, there have been a number of major improvements to the Heritage Assets since the introduction of the Heritage Contract, including:

- Aberfeldie: Redevelopment of the Aberfeldie facility increased the generating capacity from 5 MW to 25 MW. The three unit, 25 MW power plant came into service in 2009 (energy impact: +40 GWh);
- GM Shrum: Through a combination of reliability upgrades and capacity increases between 2007 and 2015, the generating ability of the GM Shrum facility has increased by 186 MW (energy impact: +135 GWh);
- Revelstoke/Mica: One new unit at Revelstoke came into service in 2010. At Mica, one new unit came into service in 2015 and another in 2016. Together these new units add 1,565 MW of generating capacity to the BC Hydro system (energy impact: +330 GWh);
- Ruskin: The Ruskin Dam and Powerhouse Upgrade project went into service in 2018, resulting in a capacity increase from 105 MW to 114 MW (energy impact: +25 GWh);
- Fort Nelson: The Fort Nelson facility was upgraded from a simple cycle to combined cycle facility in 2012, upgrading the gas turbine generator and adding a second steam turbine generator. The upgrade project increased the generating capacity to 72 MW (energy impact: +190 GWh);
- John Hart: A redevelopment project is in progress and expected to enter service in fiscal 2019, adding approximately 8 MW (energy impact: +52 GWh) to BC Hydro's generation system on Vancouver Island; and
- Cheakamus: A project to address reliability risks with the generators is in progress and expected to enter service in fiscal 2019 and fiscal 2020. This will remediate reliability risks and add an incremental 23 MW (energy impact: +45 GWh) to BC Hydro's generation system capacity in the Lower Mainland.

It is important to note that the improvements completed and in progress to BC Hydro's Heritage Assets provide additional capacity and energy that greatly exceeds the impairments and reductions noted above.

Lastly, there have been some changes to the Heritage Assets since the introduction of the Heritage Contract, including:

- Burrard (900 MW): Generation at the facility ended in 2016, after which Burrard has functioned only as a synchronous condenser facility. The BCUC granted permission to permanently cease generation operations in 2016 (energy impact: -6100 GWh).; and

- Lake Buntzen 2 (18 MW): The facility was taken out of service in 2002, and, in 2010, BC Hydro received approval from the BCUC to permanently cease operations at Lake Buntzen 2 (energy impact: -15 GWh).

**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.**

It is BC Hydro's view that there is no benefit to changing the definition of Heritage Energy. As discussed in greater detail above, a change in the definition of Heritage Energy would not impact how BC Hydro plans or operates its system nor would it impact the cost of energy paid by ratepayers.

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

df/rh