British Columbia Hydro and Power Authority

2017/18

FIRST QUARTER REPORT

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the three months ended June 30, 2017 and should be read in conjunction with the MD&A presented in the 2017 Annual Service Plan Report, the 2017 Audited Consolidated Financial Statements and related notes of the Company, and the Unaudited Condensed Consolidated Interim Financial Statements and related notes of the Company for the three months ended June 30, 2017.

The Company applies accounting standards as prescribed by the Province of British Columbia (the Province) which combines the accounting principles of International Financial Reporting Standards (IFRS) with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* (ASC 980) (collectively the Prescribed Standards). All financial information is expressed in Canadian dollars unless otherwise specified.

This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of the Company. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward-looking statements.

HIGHLIGHTS

- Net income for the three months ended June 30, 2017 was $92 million, $4 million higher than the same period in the prior fiscal year. Domestic revenues were $59 million higher than the same period in the prior fiscal year primarily due to higher average customer rates reflecting an average interim rate increase as approved by the British Columbia Utilities Commission (BCUC) of 3.5 per cent effective April 1, 2017. This was partially offset by $20 million higher domestic cost of energy mainly due to higher planned purchases from Independent Power Producers, $9 million higher asset related costs, and $9 million higher finance charges.

- Water inflows to the system during the three months ended June 30, 2017 were 110 per cent of average compared to 105 per cent of average in the same period in the prior fiscal year. The above average inflows in fiscal 2018 were the result of higher snowmelt in the Columbia region.

- Capital expenditures, before contributions in aid of construction, for the three months ended June 30, 2017 were $576 million, comparable to $580 million in the same period in the prior fiscal year. BC Hydro continues to invest significantly in capital projects to refurbish its aging infrastructure and build new assets for future growth, including Site C Clean Energy project, John Hart Generating Station Replacement project, Ruskin Dam Safety and Powerhouse Upgrade project, Distribution Wood Poles Replacements program, W.A.C. Bennett Dam Riprap Upgrade project, and Horne Payne Substation Upgrade project.

CONSOLIDATED RESULTS OF OPERATIONS

($ in millions)	*For the three months ended June 30* **2017**	2016	Change
Total Revenues	**$ 1,465**	$ 1,327	$ 138
Net Income	**$ 92**	$ 88	$ 4
Capital Expenditures	**$ 576**	$ 580	$ (4)
GWh Sold (Domestic)	**12,825**	13,459	(634)

($ in millions)	***June 30, 2017***	*March 31, 2017*	Change
Total Assets	**$ 32,055**	$ 31,888	$ 167
Shareholder's Equity	**$ 4,862**	$ 4,909	$ (47)
Accrued Payment to the Province	**$ 159**	$ -	$ 159
Retained Earnings	**$ 4,755**	$ 4,822	$ (67)
Debt to Equity	**80 : 20**	80 : 20	n/a
Number of Domestic Customer Accounts	**1,994,013**	1,987,963	6,050
Total Reservoir Storage (GWh)	**26,576**	14,526	12,050

REVENUES

Total revenues after regulatory account transfers for the three months ended June 30, 2017 were $1,465 million, an increase of $138 million or 10 per cent compared to the same period in the prior fiscal year. The increase was primarily due to higher trade revenue mainly resulting from a 32 per cent increase in the average trade energy sales price. In addition, there was also higher domestic revenue mainly due to higher average customer rates and higher transfers to the Rate Smoothing regulatory account to smooth the impacts of the rate increases during the 10 Year Rates Plan period. The table below shows revenues before regulatory account transfers, the amount of regulatory account transfers, and total revenues after regulatory account transfers as follows:

for the three months ended June 30	*(in millions)* **2017**	2016	*(gigawatt hours)* **2017**	2016	*($ per MWh)* [2] **2017**	2016
Domestic						
Residential	**$ 436**	$ 392	**3,798**	3,594	**$ 114.80**	$ 109.07
Light industrial and commercial	**430**	432	**4,361**	4,558	**98.60**	94.78
Large industrial	**182**	180	**3,178**	3,125	**57.27**	57.60
Other sales	**83**	90	**1,488**	2,182	**55.78**	41.25
Total Domestic Revenue Before Regulatory Transfers	**1,131**	1,094	**12,825**	13,459	**88.19**	81.28
Rate smoothing and energy deferral regulatory transfers	**98**	76	-	-	-	-
Total Domestic	**$ 1,229**	$ 1,170	**12,825**	13,459	**$ 95.83**	$ 86.93
Trade						
Gross electricity and gas	**$ 354**	$ 248	**10,127**	9,682	**$ 31.03**	$ 23.47
Less: forward electricity and gas purchases	**(118)**	(91)	-	-	-	-
Total Trade[1]	**$ 236**	$ 157	**10,127**	9,682	**$ 23.30**	$ 16.22
Total	**$ 1,465**	$ 1,327	**22,952**	23,141	**$ 63.83**	$ 57.34

[1] Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer and this is reflected in the cost of energy table.
[2] The Trade $ per MWh represents the gross $ per MWh of physical transactions and does not include financial transactions. The Total Trade $ per MWh is a simple average calculation and does not reflect actual trade energy prices during the period.

Domestic Revenues

Domestic revenues for the three months ended June 30, 2017 were $1,229 million, an increase of $59 million or 5 per cent compared to the same period in the prior fiscal year. The increase over the prior fiscal year, before regulatory account transfers, was primarily due to $44 million higher residential revenues which were mainly driven by colder weather in the current period compared to the same period in the prior fiscal year and higher average customer rates that reflect the 3.5 per cent interim rate increase as approved by the BCUC effective April 1, 2017. The decrease in consumption for light industrial and commercial customers was mainly due to decreased activity in the manufacturing and commercial sectors.

In addition, there were $22 million higher regulatory account transfers related to the Rate Smoothing account, Non-Heritage Deferral Account (NHDA), and Heritage Deferral Account (HDA). Changes to regulatory account balances are discussed in the *Regulatory Transfers* section.

Variances between actual and planned load are deferred to the NHDA and variances between actual and planned other energy sales are deferred to the HDA and NHDA.

Trade Revenues

Powerex, a wholly owned subsidiary of the Company, is an active participant in western energy markets, buying and selling wholesale power, natural gas, ancillary services, clean and renewable power, and environmental products.

The Company's electricity system is interconnected with systems in Alberta and the Western United States, facilitating sales and purchases of electricity outside of British Columbia. Powerex's trade activities earn income to lower the Company's customer rates and to help balance its system by being able to import energy to meet domestic demand when there is a supply shortage and exporting energy when there is a supply surplus. Exports are made only after ensuring domestic demand requirements are met.

Total trade revenues for the three months ended June 30, 2017 were $236 million, an increase of $79 million or 50 per cent compared to the same period in the prior fiscal year. The increase in trade revenues was primarily due to a 32 per cent increase in the average energy sales price. Higher average electricity sales prices were primarily driven by increased demand in California due to hot weather and a series of heatwaves, while higher average gas sales prices were primarily driven by a more balanced supply and demand picture in North America compared to the same period in the prior fiscal year.

Variances between actual and planned trade revenues are transferred to the Trade Income Deferral Account (TIDA).

OPERATING EXPENSES

For the three months ended June 30, 2017, total operating expenses, after regulatory account transfers, of $1,215 million were $125 million higher than the same period in the prior fiscal year. The increase over the prior fiscal year was primarily due to higher trade energy costs, higher planned purchases from Independent Power Producers, and higher dismantling costs that were expensed as planned in the current period, but drew down the balance in a regulatory account during the same period in the prior fiscal year.

Cost of Energy

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and transmission and other charges. Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand, and environmental and social impacts.

Total energy costs after regulatory transfers for the three months ended June 30, 2017 were $580 million, $99 million or 21 per cent higher than the same period in the prior fiscal year. The increase over the prior fiscal year was primarily due to higher trade energy costs mainly resulting from higher average gas purchase prices and higher planned purchases from Independent Power Producers. The table below shows energy costs before regulatory account transfers, the amount of regulatory account transfers, and total energy costs after regulatory account transfers as follows:

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the three months ended June 30	**2017**	2016	**2017**	2016	**2017**	2016
Domestic						
Water rental payments (hydro generation) [1]	**$ 81**	$ 88	**9,598**	10,176	**$ 8.44**	$ 8.65
Purchases from Independent Power Producers	**315**	292	**4,203**	4,022	**74.95**	72.60
Other electricity purchases - Domestic	**-**	-	**23**	11	**-**	-
Gas for thermal generation	**2**	6	**-**	41	**-**	146.34
Transmission charges and other expenses	**1**	5	**25**	25	**-**	-
Allocation from (to) trade energy	**1**	-	**152**	44	**13.31**	15.90
Total Domestic Cost of Energy Before Regulatory Transfers	**400**	391	**14,001**	14,319	**28.57**	27.31
Energy deferral regulatory transfers	**(9)**	(20)	**-**	-	**-**	-
Total Domestic	**$ 391**	$ 371	**14,001**	14,319	**$ 27.93**	$ 25.91
Trade						
Gross electricity and remarketed gas	**$ 192**	$ 137	**10,126**	9,819	**$ 18.67**	$ 13.77
Less: forward electricity and gas purchases	**(118)**	(91)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**74**	46	**-**	-	**-**	-
Transmission charges and other expenses	**82**	65	**-**	-	**-**	-
Allocation (to) from domestic energy	**(1)**	-	**(152)**	(44)	**13.31**	15.90
Total Trade Cost of Energy Before Regulatory Transfers	**155**	111	**9,974**	9,775	**15.54**	11.36
Trade net margin regulatory transfer	**34**	(1)	**-**	-	**-**	-
Total Trade	**$ 189**	$ 110	**9,974**	9,775	**$ 18.95**	$ 11.25
Total Energy Costs	**$ 580**	$ 481	**23,975**	24,094	**$ 24.19**	$ 19.96

[1] Water rental payments are based on the previous calendar year's generation volumes. The volumes are actual hydro generation during the period. The $ per MWh is a simple average calculation and does not reflect actual water rental rates during the period.
[2] The $ per MWh represents the gross unit cost per physical electricity and gas transaction. The Total Trade $ per MWh is a simple average calculation and does not reflect actual trade energy prices during the period.

Domestic Energy Costs

Domestic energy costs for the three months ended June 30, 2017 were $391 million, $20 million or 5 per cent higher than the same period in the prior fiscal year. The significant variances from the prior fiscal year, before regulatory account transfers, were due to $23 million higher purchases from Independent Power Producers. This was primarily driven by higher volumes delivered due to an increased number of Independent Power Producers in operation during the current fiscal year. These costs were partially offset by $7 million lower water rental payments mainly due to the elimination of the Tier 3 water rental rate which is being phased out during calendar 2017.

Trade Energy Costs

Trade energy costs before regulatory account transfers for the three months ended June 30, 2017 were $155 million, an increase of $44 million or 40 per cent compared to same period in the prior fiscal year. The increase in trade energy costs was primarily driven by higher average gas purchase prices due to a more balanced supply and demand picture in North America compared to the same period in the prior fiscal year, partially offset by lower average electricity purchase prices in the Pacific Northwest primarily due to higher hydro generation in that region.

Variances between actual and planned trade costs are transferred to the TIDA.

Water Inflows and Reservoir Storage

Water inflows to the system during three months ended June 30, 2017 were 110 per cent of average compared to 105 per cent of average in the same period in the prior fiscal year. The above average inflows in fiscal 2018 were the result of higher snowmelt in the Columbia region during the quarter.

Total reservoir storage as at June 30, 2017 was 26,576 GWh, a decrease of 228 GWh compared to total reservoir storage as at June 30, 2016 of 26,804 GWh. System energy storage remained near the upper end of the 10-year historical range (19,944 to 27,861 GWh) due to heavy Columbia snowpack and high precipitation in May and June 2017 in the Peace region.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the three months ended June 30, 2017 were $144 million, comparable to personnel expenses of $139 million in the same period in the prior fiscal year.

Materials and External Services

Expenditures on materials and external services for the three months ended June 30, 2017 were $154 million, comparable to materials and external services of $149 million in the same period in the prior fiscal year.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, amortization of intangible assets, and the amortization of certain regulatory assets and liabilities. For the three months ended June 30, 2017 and 2016, amortization and depreciation expense was $300 million, which included $93 million (2016 - $96 million) of amortization of regulatory account balances, which is the regulatory mechanism to recover the regulatory account balances in rates.

Grants, Taxes and Other Costs

As a Crown Corporation, the Company is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts, and school tax to the Province on certain assets. Total grants, taxes and other costs for the three months ended June 30, 2017 were $77 million, $12 million higher than the same period in the prior fiscal year primarily due to higher dismantling costs that were expensed as planned in the current period, but drew down the balance in a regulatory account during the same period in the prior fiscal year.

In prior fiscal years when dismantling costs were incurred, the Dismantling Cost regulatory account (formerly the Future Removal & Site Restoration Costs regulatory account) would be drawn down. At the end of the first fiscal quarter in fiscal 2017, the regulatory account was fully drawn down resulting in costs being expensed as planned rather than being recorded in the regulatory account.

Capitalized Costs

Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from operating costs to Property, Plant & Equipment. Certain overhead costs not eligible for capitalization under IFRS are transferred from operating costs to the IFRS Property, Plant & Equipment regulatory account. These transfers are amortized over 40 years which approximates the composite average life of the Property, Plant & Equipment. In addition, starting in fiscal 2013, the ongoing impact of this change is being included in rates over a 10-year period through transfers to the IFRS Property, Plant & Equipment regulatory account as approved by the BCUC. As such, each year, 1/10 more of ineligible costs will be charged to operating costs such that by the end of year ten, all ineligible costs will be charged to operating costs.

Capitalized costs for the three months ended June 30, 2017 were $40 million, compared to capitalized costs of $44 million in the same period in the prior fiscal year. The decrease in capitalized cost is consistent with the additional ineligible costs being charged to operating costs as noted above.

FINANCE CHARGES

Finance charges for the three months ended June 30, 2017 were $158 million, $9 million higher than the same period in the prior fiscal year. The increase was primarily due to higher volume of long-term debt borrowings, higher lease charges, and higher short-term interest rates. This increase was partially offset by higher interest during construction which was capitalized.

REGULATORY TRANSFERS

The Company presents its results and financial position under the Prescribed Standards. Under the Prescribed Standards, the Company applies the principles of IFRS combined with ASC 980 to reflect the rate-regulated environment in which the Company operates. These Prescribed Standards allow for the deferral of costs and recoveries that under IFRS may otherwise be included in the determination of total comprehensive income in the year the amounts are incurred or would be reflected in rates. The deferred amounts are either recovered or refunded through future rate adjustments.

The Company has established various regulatory accounts through rate regulation and with the approval of the BCUC. The use of regulatory accounts is common amongst regulated utility industries throughout North America. BC Hydro uses various regulatory accounts, in compliance with BCUC orders, in order to better match costs and benefits for different generations of customers, smooth out the rate impact of large non-recurring costs, and defer to future periods differences between forecast and actual costs or revenues. Regulatory accounts allow the Company to defer certain types of revenue and cost variances through transfers to and from the accounts which are then included in customer rates in future periods, subject to approval by the BCUC and have the effect of adjusting net income.

Net regulatory account transfers are comprised of the following:

(in millions)		*For the three months ended June 30* **2017**		2016
Energy Deferral Accounts				
Heritage Deferral Account	**$**	**(4)**	$	(18)
Non-Heritage Deferral Account		**36**		66
Trade Income Deferral Account		**(32)**		1
		-		49
Forecast Variance Accounts				
Total Finance Charges		**(5)**		(1)
Rate Smoothing		**60**		48
Pension Costs		**2**		2
Debt Management		**(4)**		80
Other		**(2)**		(2)
		51		127
Capital-Like Accounts				
Demand-Side Management		**9**		16
IFRS Property, Plant & Equipment		**22**		28
		31		44
Non-Cash Accounts				
Environmental Provisions & Costs		**1**		8
First Nations Provisions & Costs		**6**		1
Other		**(1)**		-
		6		9
Amortization of regulatory accounts		**(93)**		(96)
Interest on regulatory accounts		**17**		20
Net change in regulatory accounts	**$**	**12**	$	153

For the three months ended June 30, 2017, there was a net addition of $12 million to the Company's regulatory accounts compared to a net addition of $153 million in the same period in the prior fiscal year. The net regulatory asset balance as at June 30, 2017 was $5,609 million compared to $5,597 million as at March 31, 2017.

Net additions to the regulatory accounts during the three months ended June 30, 2017 included:

- Increase of $60 million of planned additions to the Rate Smoothing regulatory account to smooth the impacts of the rate increases during the 10 Year Rates Plan period;

- Transfer of $22 million of planned additions to the IFRS Property, Plant & Equipment regulatory account for smoothing the rate impact of overhead costs not eligible for capitalization under IFRS as they are not considered directly attributable to the construction of capital assets; and

- Interest on regulatory accounts of $17 million.

These net additions were partially offset by net amortization of $93 million which is the regulatory mechanism to recover the regulatory account balances in rates.

BC Hydro has regulatory mechanisms in place or has applied for regulatory mechanisms in the Fiscal 2017-2019 Revenue Requirements Application to collect 24 of 26 regulatory accounts in use or with balances at June 30, 2017 in rates over various periods, which represent approximately 82 per cent of the total net regulatory asset account balance.

PAYMENT TO THE PROVINCE

Under a Special Directive from the Province, the Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Special Directive states that for fiscal 2018 and subsequent years, the Payment will be reduced by $100 million per year based on the Payment in the immediate preceding fiscal year until it reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

The fiscal 2017 Payment to the Province was $259 million and was paid in March 2017. Under the Special Directive, the Payment for fiscal 2018 will be $159 million. As a result, the Company has accrued $159 million as at June 30, 2017 (2016 - $nil).

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the three months ended June 30, 2017 was $339 million, compared to $44 million in the same period in the prior fiscal year. The increase was mainly due to higher domestic revenue primarily due to higher average customer rates, higher trade revenue due to an increase in the average energy sales price, and higher cash flow provided from changes in working capital.

The long-term debt balance net of sinking funds as at June 30, 2017 was $20,022 million compared to $19,845 million as at March 31, 2017. The increase was mainly a result of an increase in long-term bond issuances for net proceeds of $295 million ($300 million par value). This increase was partially offset by lower revolving borrowings of $65 million and long-term bond redemptions totaling $40 million par value. Long-term debt increased primarily to fund capital expenditures.

CAPITAL EXPENDITURES

Capital expenditures include property, plant and equipment and intangible assets. The capital expenditures, before contributions-in-aid of construction, were as follows:

(in millions)	*For the three months ended June 30* **2017**	2016
Transmission lines and substations replacements and expansion	**$ 113**	$ 116
Generation replacements and expansion	**137**	134
Distribution system improvements and expansion	**120**	115
General, including technology, vehicles and buildings	**42**	60
Site C Clean Energy project	**164**	155
Total Capital Expenditures	**$ 576**	$ 580

Total capital expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the Consolidated Statements of Cash Flows because the expenditures above include accruals.

Transmission lines and substation capital expenditures include expenditures on the Horne Payne Substation Upgrade project, South Fraser Transmission Relocation project, Fernie Substation Upgrade project, Transmission Wood Structure and Framing Replacement program, Campbell River Substation Capacity Upgrade project, Spacer Damper Replacement program, Kamloops Substation project, and Bear Mountain Terminal Load Capacity Increase project.

Generation capital expenditures include expenditures for John Hart Generating Station Replacement project, Ruskin Dam Safety and Powerhouse Upgrade project, W.A.C. Bennett Dam Riprap Upgrade project, and Bridge River 1 Unit Transformers T1 & T2 Replacement project.

Distribution capital expenditures include expenditures on customer driven work, end of life asset replacements, and system expansion and improvements.

General capital expenditures include expenditures on various building development programs, technology projects, and vehicles.

Site C Clean Energy project expenditures relate to site preparation, clearing for reservoir and transmission lines, engineering and design, as well as social and land programs in addition to main civil works.

RATE REGULATION

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy, and earn an annual rate of return.

BC Hydro Fiscal 2017-2019 Revenue Requirements Application

In July 2016, BC Hydro filed an Application to approve its revenue requirements for a three year test period covering fiscal 2017 to fiscal 2019. The Application requested rate increases of 4.0 per cent for fiscal 2017, 3.5 per cent for fiscal 2018, and 3.0 per cent in fiscal 2019 in alignment with the 10 Year Rates Plan. The BCUC has approved interim, refundable rate increases of 4.0 and 3.5 for fiscal 2017 and 2018, while it evaluates the full Revenue Requirements Application.
From October 2016 through May 2017, BC Hydro responded to over 3,700 information requests about the Application from Interveners and the BCUC over three separate rounds of information requests. BC Hydro filed its Reply Argument in early July 2017, thereby closing the evidentiary record. BC Hydro expects a decision from the BCUC by early October 2017.

Customer Emergency Fund

In response to the BCUC Directive to file a crisis intervention fund pilot program, BC Hydro filed an application for a pilot program called the Customer Emergency Fund on July 24, 2017. This pilot proposes to provide grants of up to $600 for eligible residential customers in short-term financial hardship. The pilot is proposed to be funded by a 25 cent per month rate rider on residential customer bills. This rate rider is equivalent to approximately ¼ of one per cent of an average residential customer bill. The pilot is proposed to run for two years, from July 2018 to July 2020, to be followed by an evaluation of its benefits and costs. BC Hydro expects the BCUC to determine the review process in the summer of 2017.

Inquiry of Expenditures Related to the Adoption of the SAP Platform

BC Hydro filed a Consolidated Information Filing in June 2016 in compliance with BCUC Order G-81-16 providing information pertaining to BC Hydro’s investment in the SAP technology platform. The filing included background information on BC Hydro’s enterprise resource planning investments from the 1990s to present day, historical and forecast SAP-related expenditures, and a review of SAP-related project oversight and governance. On February 8, 2017 a request was made for BC Hydro to file on the record a Code of Complaint that had been submitted to BC Hydro’s Code of Conduct Advisor in April 2010, on the grounds that the complaint was directly relevant to the allegations of misconduct in the SAP enquiry. On May 31, 2017, the BCUC directed BC Hydro to file information related to a 2010 Code of Conduct complaint. BC Hydro filed the requested information on a confidential basis on June 28, 2017. The BCUC reviewed the information and circulated a redacted version of the submission to interveners on July 26, 2017 for their comments.

Supply Chain Applications Project Application

In December 2016, BC Hydro filed the Supply Chain Applications Project Application under section 44.2 for acceptance of expenditures on a new SAP IT platform to meet BC Hydro’s current and future business needs, reduce risk, and provide benefits for supply chain activities throughout BC Hydro. The project’s total capital cost is estimated between $60 million and $79 million with a committed in service date in the second quarter of fiscal 2020. The BCUC and Interveners issued the first round of information requests in February 2017, which BC Hydro responded to in early March 2017. The BCUC and Interveners issued a second round of information requests in April 2017 and BC Hydro provided responses in May 2017. In addition, in April 2017, intervener evidence was filed and responses to information requests on the intervener evidence were provided in May 2017. BC Hydro filed its Final Argument in June 2017 and its Reply Argument in July 2017. The BCUC decision on the Application is expected in early fall 2017.

Capital Expenditures and Projects Review

In May 2016, the BCUC issued Order No. G-58-16 initiating a review of the regulatory oversight of BC Hydro's capital expenditures and projects. At the request of BCUC Staff, further regulatory process will commence two weeks following the issuance of the final decision in BC Hydro's Revenue Requirements Application proceeding, which is expected in October 2017.

Site C Clean Energy Project Review

On August 2, 2017, the Province asked the BCUC to conduct an inquiry into the Site C Clean Energy Project. The BCUC has specifically been asked to confirm whether or not BC Hydro is on target to complete the Site C Clean Energy Project on budget and by 2024, and to provide advice on implications for ratepayers associated with:

- proceeding with the project;
- suspending the project, while maintaining the option to resume construction until 2024; and
- terminating the project and remediating the site.

The Terms of Reference also require the BCUC to consider whether there are other resource portfolios that could provide the same level of benefits at the same or lower cost as the Site C Clean Energy Project. The inquiry began on August 9, 2017 with a preliminary report from the BCUC required within six weeks (by September 20, 2017), and a final report required within 12 weeks (by November 1, 2017).

WANETA TRANSACTION

On August 1, 2017, BC Hydro exercised its option to purchase the remaining two-thirds share of the Waneta Dam and Generating Station (Waneta) from Teck Resources Limited (Teck) for $1.2 billion. The purchase includes a 20-year agreement with Teck where the electricity generated from the two-thirds share will continue to supply power to the Teck smelter in Trail at set prices. Teck will have an option to extend the agreement for a further 10 years. The final decision to move forward with the purchase is subject to a number of conditions, including approval by the BCUC. BC Hydro currently owns the other one-third interest in Waneta.

RISK MANAGEMENT

BC Hydro is exposed to numerous risks, which can result in safety, environmental, financial, reliability and reputational impacts. This section of the MD&A discusses risks that may impact financial performance.

The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income is mitigated through the use of BCUC-approved regulatory accounts. Regulatory accounts assist in matching costs and benefits for different generations of customers, to smooth the impact of large, non-recurring costs and to defer for future recovery in rates the differences between planned and actual costs or revenues that arise due to uncontrollable events. BC Hydro's approach to the recovery of its regulatory accounts is included in the Fiscal 2017-2019 Revenue Requirements Application.

Significant Financial Risks

The largest sources of variability in BC Hydro's financial performance are typically domestic and trade revenue, domestic and trade cost of energy, and finance charges. These are influenced by several elements, which generally fall into the following five categories: energy availability, domestic demand for energy, energy market prices, deliveries from electricity purchase agreement contracts, and interest rates. Neither a high nor a low value of any of these individual drivers is intrinsically positive or negative for BC Hydro's financial results. It is the specific combination of these drivers in any given year which has an impact.

While meeting domestic demand, environmental regulations and treaty obligations, BC Hydro attempts to operate the system to take maximum advantage of market energy prices – buying from the markets when prices are low and selling when prices are high. In doing so, BC Hydro attempts to optimize the combined effects of these elements and reduce the net cost of energy for our customers.

This section should be read in conjunction with the risks disclosed in the Risk Management section in the Management's Discussion and Analysis presented in the Annual Service Plan Report for the year ended March 31, 2017. In addition, information on risks and opportunities that could significantly impact BC Hydro meeting its objectives is outlined at www.bchydro.com/serviceplan.

FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in February 2017 forecast net income for fiscal 2018 at $698 million which is consistent with Order in Council No. 590.

The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, interest rates, and foreign exchange rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The Service Plan forecast for fiscal 2018 assumed average water inflows, domestic sales of 57,552 GWh, average market energy prices of US $25.00/MWh, short-term interest rates of 0.67 per cent, and a Canadian to US dollar exchange rate of US $0.7702.

BC Hydro filed an updated forecast with the Province in August 2017. The net income forecast for fiscal 2018 remains at $698 million.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	*For the three months ended June 30* **2017**	2016
Revenues		
Domestic	**$ 1,229**	$ 1,170
Trade	**236**	157
	1,465	1,327
Expenses		
Operating expenses (Note 3)	**1,215**	1,090
Finance charges (Note 4)	**158**	149
Net Income	**92**	88
OTHER COMPREHENSIVE INCOME		
Items Reclassified Subsequently to Net Income		
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 13)	**19**	7
Reclassification to income of derivatives designated as cash flow hedges (Note 13)	**4**	8
Foreign currency translation (losses) gains	**(3)**	1
Other Comprehensive Income	**20**	16
Total Comprehensive Income	**$ 112**	$ 104

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(in millions)	***As at June 30* 2017**	*As at March 31* 2017
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 38**	$ 49
Accounts receivable and accrued revenue	**620**	808
Inventories (Note 6)	**182**	185
Prepaid expenses	**189**	162
Current portion of derivative financial instrument assets (Note 13)	**205**	144
	1,234	1,348
Non-Current Assets		
Property, plant and equipment (Note 7)	**23,362**	22,998
Intangible assets (Note 7)	**615**	601
Regulatory assets (Note 8)	**6,122**	6,127
Derivative financial instrument assets (Note 13)	**127**	215
Other non-current assets (Note 9)	**595**	599
	30,821	30,540
	$ 32,055	$ 31,888
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 1,218**	$ 1,190
Current portion of long-term debt (Note 10)	**3,234**	2,878
Current portion of derivative financial instrument liabilities (Note 13)	**61**	60
	4,513	4,128
Non-Current Liabilities		
Long-term debt (Note 10)	**16,965**	17,146
Regulatory liabilities (Note 8)	**513**	530
Derivative financial instrument liabilities (Note 13)	**13**	41
Contributions in aid of construction	**1,791**	1,765
Post-employment benefits (Note 12)	**1,575**	1,566
Other non-current liabilities (Note 14)	**1,823**	1,803
	22,680	22,851
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**4,755**	4,822
Accumulated other comprehensive income	**47**	27
	4,862	4,909
	$ 32,055	$ 31,888

Commitments (Note 7)

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

Approved on behalf of the Board:

Kenneth G. Peterson
Chair, Board of Directors

Len Boggio, FCPA, FCA, ICD.D
Chair, Audit & Finance Committee

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve	Unrealized Gains (Losses) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2016	$ 77	$ (34)	$ 43	$ 60	$ 4,397	$ 4,500
Comprehensive Income	1	15	16	-	88	104
Balance as at June 30, 2016	$ 78	$ (19)	$ 59	$ 60	$ 4,485	$ 4,604
Balance as at April 1, 2017	$ 83	$ (56)	$ 27	$ 60	$ 4,822	$ 4,909
Payment to the Province (Note 11)	-	-	-	-	(159)	(159)
Comprehensive Income (Loss)	(3)	23	20	-	92	112
Balance as at June 30, 2017	$ 80	$ (33)	$ 47	$ 60	$ 4,755	$ 4,862

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(in millions)	*For the three months ended June 30* **2017**	2016
Operating Activities		
Net income	**$ 92**	$ 88
Regulatory account transfers (Note 8)	**(105)**	(249)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Notes 5 and 8)	**93**	96
Amortization and depreciation expense (Note 5)	**207**	195
Unrealized losses on mark-to-market of financial instruments	**21**	61
Employee benefit plan expenses	**27**	29
Interest accrual	**194**	185
Other items	**19**	22
	548	427
Changes in:		
Accounts receivable and accrued revenue	**186**	96
Prepaid expenses	**(29)**	(14)
Inventories	**2**	(32)
Accounts payable, accrued liabilities and other non-current liabilities	**(93)**	(160)
Contributions in aid of construction	**30**	26
Other non-current assets	**2**	(7)
	98	(91)
Interest paid	**(307)**	(292)
Cash provided by operating activities	**339**	44
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(533)**	(543)
Cash used in investing activities	**(533)**	(543)
Financing Activities		
Long-term debt:		
Issued (Note 10)	**295**	201
Retired (Note 10)	**(40)**	-
Receipt of revolving borrowings	**2,577**	2,677
Repayment of revolving borrowings	**(2,642)**	(2,059)
Payment to the Province (Note 11)	**-**	(326)
Other items	**(7)**	(4)
Cash provided by financing activities	**183**	489
Decrease in cash and cash equivalents	**(11)**	(10)
Cash and cash equivalents, beginning of period	**49**	44
Cash and cash equivalents, end of period	**$ 38**	$ 34

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

NOTE 1: REPORTING ENTITY

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, conserve and supply power. BC Hydro owns and operates electric generation, transmission and distribution facilities in the province of British Columbia.

The condensed consolidated interim financial statements (interim financial statements) of BC Hydro include the accounts of BC Hydro and its principal wholly-owned operating subsidiaries Powerex Corp. (Powerex), Powertech Labs Inc. (Powertech), and Columbia Hydro Constructors Ltd. (Columbia), (collectively with BC Hydro, the Company) including BC Hydro's one third interest in the Waneta Dam and Generating Facility (Waneta). All intercompany transactions and balances are eliminated on consolidation.

The Company accounts for its one third interest in Waneta as a joint operation. The interim financial statements include the Company's proportionate share in Waneta, including its share of any liabilities and expenses incurred jointly with Teck Metals Ltd. and its revenue from the sale of the output in relation to Waneta.

NOTE 2: BASIS OF PRESENTATION

Basis of Accounting

These interim financial statements have been prepared in accordance with the significant accounting policies that have been established based on the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). In accordance with the directive issued by the Province's Treasury Board, BC Hydro is to prepare these interim financial statements in accordance with the accounting principles of International Financial Reporting Standards (IFRS), combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations* (collectively, the Prescribed Standards). The application of ASC 980 results in BC Hydro recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the British Columbia Utilities Commission (BCUC) for inclusion in future customer rates. Such regulatory costs and recoveries would be included in the determination of comprehensive income unless recovered in rates in the year the amounts are incurred.

The impact of the application of ASC 980 on these interim financial statements with respect to BC Hydro's regulatory accounts is described in Note 8.

These interim financial statements have been prepared by management in accordance with principles of IAS 34, *Interim Financial Reporting* and the Prescribed Standards and were prepared using the same accounting policies as described in BC Hydro's 2017 Annual Service Plan Report. Effective April 1, 2017, BC Hydro adopted amendments to various accounting standards that did not have a significant impact on these interim financial statements. These interim financial statements should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2017 Annual Service Plan Report.

These interim financial statements were approved on behalf of the Board of Directors on August 24, 2017.

NOTE 3: OPERATING EXPENSES

(in millions)	*For the three months ended June 30* **2017**	2016
Electricity and gas purchases	**$ 458**	$ 350
Water rentals	**79**	90
Transmission charges	**43**	41
Personnel expenses	**144**	139
Materials and external services	**154**	149
Amortization and depreciation (Note 5)	**300**	300
Grants, taxes and other costs	**77**	65
Less: Capitalized costs	**(40)**	(44)
	$ 1,215	$ 1,090

NOTE 4: FINANCE CHARGES

(in millions)	*For the three months ended June 30* **2017**	2016
Interest on long-term debt	**$ 200**	$ 186
Interest on finance lease liabilities	**11**	5
Less: Other recoveries	**(21)**	(23)
Capitalized interest	**(32)**	(19)
	$ 158	$ 149

NOTE 5: AMORTIZATION AND DEPRECIATION

(in millions)	*For the three months ended June 30* **2017**	2016
Depreciation of property, plant and equipment	**$ 186**	$ 177
Amortization of intangible assets	**21**	18
Amortization of regulatory accounts (Note 8)	**93**	105
	$ 300	$ 300

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE MONTHS ENDED JUNE 30, 2017

NOTE 6: INVENTORIES

(in millions)	***As at June 30 2017***	*As at March 31* 2017
Materials and supplies	**$ 141**	$ 145
Natural gas trading inventories	**41**	40
	$ 182	$ 185

No natural gas trading inventories are pledged as security for liabilities.

NOTE 7: PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Property, plant and equipment and intangible asset expenditures, before contributions in aid of construction, for the three months ended June 30, 2017 were $576 million (2016 - $580 million).

As of June 30, 2017, the Company has contractual commitments to spend $3,207 million on major property, plant and equipment projects (for individual projects greater than $50 million).

NOTE 8: RATE REGULATION

In July 2016, BC Hydro filed the Fiscal 2017-2019 Revenue Requirements Application requesting rate increases of 4.0 per cent, 3.5 per cent, and 3.0 per cent for fiscal 2017, 2018, and 2019, respectively, in accordance with Direction No. 7 issued by the Province in March 2014. The BCUC approved interim rate increases of 4.0 per cent for fiscal 2017 and 3.5 per cent for fiscal 2018. The results for the three months ended June 30, 2017 reflect the interim approved rate increase of 3.5 per cent for fiscal 2018 and the orders sought by BC Hydro with respect to regulatory accounts as filed in the Application. A decision from the BCUC on the Fiscal 2017-2019 Revenue Requirements Application is expected in early fall of calendar 2017.

Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. In the absence of rate regulation, these amounts would be reflected in total comprehensive income unless the Company sought recovery through rates in the year in which they are incurred. For the three months ended June 30, 2017, the impact of regulatory accounting has resulted in a net increase to total comprehensive income of $12 million (2016 - $153 million increase). For each regulatory account, the amount reflected in the Net Change column in the following regulatory tables represents the impact on comprehensive income for the applicable year, unless otherwise recovered through rates. Under rate regulated accounting, a net decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to comprehensive income.

Transfers to the regulatory accounts for the three months ended June 30, 2017 are based on the Fiscal 2017-2019 Revenue Requirements Application, which remains subject to approval by the BCUC.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE MONTHS ENDED JUNE 30, 2017

(in millions)	*As at April 1 2017*	*Addition (Reduction)*	*Interest*	*Amortization*	*Net Change*	*As at June 30 2017*
Regulatory Assets						
Non-Heritage Deferral Account	$ 756	$ 36	$ 8	$ (43)	$ 1	$ 757
Trade Income Deferral Account	194	(32)	2	(11)	(41)	153
Demand-Side Management	916	9	-	(24)	(15)	901
First Nations Provisions & Costs	532	6	1	(10)	(3)	529
Pension Costs	511	2	-	(8)	(6)	505
Site C	453	-	5	-	5	458
CIA Amortization	91	(1)	-	-	(1)	90
Environmental Provisions & Costs	294	1	-	(8)	(7)	287
Smart Metering & Infrastructure	261	-	3	(8)	(5)	256
IFRS Pension	574	-	-	(10)	(10)	564
IFRS Property, Plant & Equipment	962	22	-	(6)	16	978
Rate Smoothing	488	60	-	-	60	548
Other Regulatory Accounts	95	5	-	(4)	1	96
Total Regulatory Assets	6,127	108	19	(132)	(5)	6,122
Regulatory Liabilities						
Heritage Deferral Account	53	4	1	(3)	2	55
Foreign Exchange Gains and Losses	66	3	-	(10)	(7)	59
Debt Management	187	4	-	-	4	191
Total Finance Charges	215	5	-	(25)	(20)	195
Other Regulatory Accounts	9	4	1	(1)	4	13
Total Regulatory Liabilities	530	20	2	(39)	(17)	513
Net Regulatory Asset	$ 5,597	$ 88	$ 17	$ (93)	$ 12	$ 5,609

NOTE 9: OTHER NON-CURRENT ASSETS

(in millions)	***As at June 30 2017***	*As at March 31* 2017
Non-current receivables	**$ 281**	$ 278
Sinking funds	**177**	179
Other	**137**	142
	$ 595	$ 599

Included in the non-current receivables balance are $182 million of receivables (March 31, 2017 - $184 million) attributable to contributions in aid of construction and tariff supplemental charges related to a transmission line and $65 million of receivables (March 31, 2017 - $68 million) from mining customers participating in the Mining Customer Payment Plan that was established in February 2016 as a result of a direction from the Province.

NOTE 10: LONG-TERM DEBT AND DEBT MANAGEMENT

The Company's long-term debt comprises bonds and revolving borrowings obtained under an agreement with the Province.

The Company has a commercial paper borrowing program with the Province which is limited to $4,500 million, and is included in revolving borrowings. At June 30, 2017, the outstanding amount under the borrowing program was $2,774 million (March 31, 2017 - $2,838 million).

For the three months ended June 30, 2017, the Company issued bonds with net proceeds of $295 million (2016 - $201 million) and a par value of $300 million (2016 - $200 million), a weighted average effective interest rate of 2.9 per cent (2016 - 2.2 per cent) and a weighted average term to maturity of 31.0 years (2016 - 10.1 years).

For the three months ended June 30, 2017, there were $40 million par value in bond maturities (2016 - $nil).

NOTE 11: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining the Company's equity for regulatory purposes, as well as the annual Payment to the Province (see below). Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province. For this purpose, the applicable Order in Council defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and cash and cash equivalents. Equity comprises retained earnings, accumulated other comprehensive income, and contributed surplus. The Company monitors its capital structure on the basis of its debt to equity ratio.

During the three months ended June 30, 2017, there were no changes in the approach to capital management.

The debt to equity ratio at June 30, 2017, and March 31, 2017 was as follows:

(in millions)	***As at June 30*** **2017**	*As at March 31* 2017
Total debt, net of sinking funds	**$ 20,022**	$ 19,845
Less: Cash and cash equivalents	**(38)**	(49)
Net Debt	**$ 19,984**	$ 19,796
Retained earnings	**$ 4,755**	$ 4,822
Contributed surplus	**60**	60
Accumulated other comprehensive income	**47**	27
Total Equity	**$ 4,862**	$ 4,909
Net Debt to Equity Ratio	**80 : 20**	80 : 20

Payment to the Province

Under a Special Directive from the Province, the Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Special Directive states that for fiscal 2018 and subsequent years, the Payment will be reduced by $100 million per year based on the Payment in the immediate preceding fiscal year until it reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

The fiscal 2017 Payment to the Province was $259 million and was paid in March 2017. Under the Special Directive, the Payment for fiscal 2018 will be $159 million. As a result, the Company has accrued $159 million as at June 30, 2017 (2016 - $nil).

NOTE 12: POST-EMPLOYMENT BENEFITS

The expense recognized for the Company's defined benefit plans prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions and prior to the application of regulatory accounting for the three months ended June 30, 2017 was $41 million (2016 - $42 million).

Company contributions to the registered defined benefit pension plans for the three months ended June 30, 2017 were $10 million (2016 - $14 million).

NOTE 13: FINANCIAL INSTRUMENTS

Finance charges, including interest income and expenses, for financial instruments disclosed in this note are prior to the application of regulatory accounting for the three months ended June 30, 2017 and 2016 (except where noted).

Categories of Financial Instruments

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at June 30, 2017 and March 31, 2017. The non-derivative financial instruments, where carrying value differs from fair value, are classified as Level 2 of the fair value hierarchy.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE MONTHS ENDED JUNE 30, 2017

	June 30, 2017		March 31, 2017	
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Financial Assets and Liabilities at Fair Value Through Profit or Loss:				
Cash equivalents - short-term investments	**$ 38**	**$ 38**	$ 24	$ 24
Loans and Receivables:				
Accounts receivable and accrued revenue	**620**	**620**	808	808
Non-current receivables	**281**	**285**	278	282
Cash	**-**	**-**	25	25
Held to Maturity:				
Sinking funds – US	**177**	**194**	179	197
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**(1,218)**	**(1,218)**	(1,190)	(1,190)
Revolving borrowings	**(2,774)**	**(2,774)**	(2,838)	(2,838)
Long-term debt (including current portion due in one year)	**(17,425)**	**(20,122)**	(17,186)	(19,601)
First Nations liabilities (non-current portion)	**(384)**	**(582)**	(394)	(549)
Finance lease obligations (non-current portion)	**(191)**	**(191)**	(197)	(197)
Other liabilities	**(360)**	**(364)**	(336)	(342)

The carrying value of cash, cash equivalents, loans and receivables, accounts payable and accrued liabilities, and revolving borrowings approximates fair value due to the short duration of these financial instruments.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE MONTHS ENDED JUNE 30, 2017

The fair value of derivative instruments designated and not designated as hedges, was as follows:

(in millions)	**June 30, 2017 Fair Value**	March 31, 2017 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ 61**	$ 68
Foreign currency contracts (cash flow hedges for €EURO denominated long-term debt)	**-**	(27)
	61	41
Non-Designated Derivative Instruments:		
Interest rate contracts	**198**	194
Foreign currency contracts	**(30)**	-
Commodity derivatives	**29**	23
	197	217
Net asset	**$ 258**	$ 258

The carrying value of derivative instruments designated and not designated as hedges was the same as the fair value.

The derivatives are represented on the statement of financial position as follows:

(in millions)	**June 30, 2017**	March 31, 2017
Current portion of derivative financial instrument assets	**$ 205**	$ 144
Current portion of derivative financial instrument liabilities	**(61)**	(60)
Derivative financial instrument assets, non-current	**127**	215
Derivative financial instrument liabilities, non-current	**(13)**	(41)
Net asset	**$ 258**	$ 258

For designated cash flow hedges for the three months ended June 30, 2017, a gain of $1 million (2016 - $nil) related to the ineffective portion was recognized in finance charges and then transferred to the Total Finance Charges regulatory account.

For designated cash flow hedges for the three months ended June 30, 2017, a gain of $19 million (2016 - gain of $7 million) was recognized in other comprehensive income. For the three months ended June 30, 2017, $4 million (2016 - $8 million) was reclassified from other comprehensive income and reported in net income, offsetting foreign exchange gains (2016 - gains) recorded in the period.

For interest rate contracts not designated as hedges with an aggregate notional principal of $3.4 billion, used to economically hedge the interest rates on future debt issuances, there was a $19 million increase in the fair value of these contracts for the three months ended June 30, 2017 (2016 - $29 million decrease). For the interest rate contracts with an aggregate notional principal of $1.0 billion for debt issued to date, there was a $15 million decrease in the fair value of a contract that settled during the period for the three months ended June 30, 2017 (2016 - $nil, no settled interest rate contracts). The net increase of $4 million in fair value of these interest rate contracts during the period were recognized in finance charges and then transferred to the Debt Management regulatory account which had a balance of $191 million as at June 30, 2017.

For foreign currency contracts not designated as hedges, which comprise primarily of foreign currency contracts for U.S. revolving borrowings, for the three months ended June 30, 2017, such contracts had a loss of $26 million (2016 - gain of $3 million) which was recognized in finance charges. These economic hedges offset $27 million of foreign exchange revaluation gains (2016 - loss of $3 million) recorded in finance charges with respect to U.S. revolving borrowings for the three months ended June 30, 2017.

For commodity derivatives not designated as hedges, a net loss of $13 million (2016 - loss of $30 million) was recorded in trade revenue for the three months ended June 30, 2017.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

	For the three months ended June 30	
(in millions)	**2017**	2016
Deferred inception loss, beginning of the period	**$ 36**	$ 48
New transactions	**(4)**	(4)
Amortization	**(5)**	(1)
Foreign currency translation loss	**(1)**	-
Deferred inception loss, end of the period	**$ 26**	$ 43

Fair Value Hierarchy

The following provides an analysis of financial instruments that are measured subsequent to initial recognition at fair value, grouped based on the lowest level of input that is significant to that fair value measurement.

The inputs used in determining fair value are characterized by using a hierarchy that prioritizes inputs based on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 - values are quoted prices (unadjusted) in active markets for identical assets and liabilities.
- Level 2 - inputs are those other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, as of the reporting date.
- Level 3 - inputs are those that are not based on observable market data.

The following tables present the financial instruments measured at fair value for each hierarchy level as at June 30, 2017 and March 31, 2017:

As at June 30, 2017 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 38	$ -	$ -	$ 38
Derivatives designated as hedges	-	69	-	69
Derivatives not designated as hedges	25	209	29	263
	$ 63	$ 278	$ 29	$ 370

As at June 30, 2017 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (8)	$ -	$ (8)
Derivatives not designated as hedges	(26)	(39)	(1)	(66)
	$ (26)	$ (47)	$ (1)	$ (74)

As at March 31, 2017 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 24	$ -	$ -	$ 24
Derivatives designated as hedges	-	72	-	72
Derivatives not designated as hedges	39	207	41	287
	$ 63	$ 279	$ 41	$ 383

As at March 31, 2017 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (31)	$ -	$ (31)
Derivatives not designated as hedges	(52)	(14)	(4)	(70)
	$ (52)	$ (45)	$ (4)	$ (101)

The Company determines Level 2 fair values for debt securities and derivatives using discounted cash flow techniques, which use contractual cash flows and market-related discount rates.

Level 2 fair values for energy derivatives are determined using inputs other than unadjusted quoted prices that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices). Level 2 includes bilateral and over-the-counter contracts valued using interpolation from observable forward curves or broker quotes from active markets for similar instruments and other publicly available data, and options valued using industry-standard and accepted models incorporating only observable data inputs.

There were no transfers between Level 1 and 2 during the period.

The following table reconciles the changes in the balance of financial instruments carried at fair value on the statement of financial position, classified as Level 3, for the three months ended June 30, 2017 and 2016:

(in millions)		
Balance as at April 1, 2017	**$**	**37**
Net loss recognized		(14)
Existing transactions settled		5
Balance as at June 30, 2017	**$**	**28**

(in millions)		
Balance as at April 1, 2016	**$**	**56**
Net loss recognized		(33)
Existing transactions settled		(1)
Balance as at June 30, 2016	**$**	**22**

Level 3 fair values for energy derivatives are determined using inputs that are based on unobservable inputs. Level 3 includes instruments valued using observable prices adjusted for unobservable basis differentials such as delivery location and product quality, instruments which are valued by extrapolation of observable market information into periods for which observable market information is not yet available, and instruments valued using internally developed or non-standard valuation models.

Powerex holds congestion products and structured power transactions that require the use of unobservable inputs when observable inputs are unavailable. Congestion products are valued using forward spreads at liquid hubs that include adjustments for the value of energy at different locations relative to the liquid hub as well as other adjustments that may impact the valuation. Option pricing models are used when the congestion product is an option. Structured power transactions are valued using standard contracts at a liquid hub with adjustments to account for the quality of the energy, the receipt or delivery location, and delivery flexibility where appropriate. Significant unobservable inputs include adjustments for the quality of the energy and the transaction location relative to the reference standard liquid hub.

During the three months ended June 30, 2017, unrealized losses of $12 million (2016 - losses of $28 million) were recognized on Level 3 derivative commodity assets held at June 30, 2017. During the three months ended June 30, 2017, unrealized losses of $2 million (2016 - losses of $4 million) were recognized on Level 3 derivative commodity liabilities held at June 30, 2017. These gains and losses are recognized in trade revenues.

Methodologies and procedures regarding Powerex's energy trading Level 3 fair value measurements are determined by Powerex's Risk Management group. Level 3 fair values are calculated within Powerex's Risk Management policies for trading activities based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, Level 3 fair value measurements are reviewed and validated by Powerex's Risk Management and Finance departments on a regular basis.

NOTE 14: OTHER NON-CURRENT LIABILITIES

(in millions)		***As at June 30* 2017**		*As at March 31* 2017
Provisions				
Environmental liabilities	**$**	**334**	$	339
Decommissioning obligations		**52**		52
Other		**14**		12
		400		403
First Nations liabilities		**402**		409
Finance lease obligations		**214**		219
Unearned revenue		**558**		551
Other liabilities		**360**		336
		1,934		1,918
Less: Current portion, included in accounts payable and accrued liabilities		**(111)**		(115)
	$	**1,823**	$	1,803

NOTE 15: SEASONALITY OF OPERATING RESULTS

Due to the seasonal nature of the Company’s operations, the condensed consolidated interim statement of comprehensive income is not indicative of operations on an annual basis. Seasonal impacts of weather, including its impact on water inflows, energy consumption within the region and market prices of energy, can have a significant impact on the Company’s operating results.

NOTE 16: SUBSEQUENT EVENT

On August 1, 2017, BC Hydro exercised its option to purchase the remaining two-thirds share of the Waneta Dam and Generating Station (Waneta) from Teck Resources Limited (Teck) for $1.2 billion. The purchase includes a 20-year agreement with Teck where the electricity generated from the two-thirds share will continue to supply power to the Teck smelter in Trail at set prices. Teck will have an option to extend the agreement for a further 10 years. The final decision to move forward with the purchase is subject to a number of conditions, including approval by the BCUC. BC Hydro currently owns the other one-third interest in Waneta.

On August 2, 2017, the Province asked the BCUC to conduct an inquiry into the Site C Clean Energy Project. The BCUC has specifically been asked to confirm whether or not BC Hydro is on target to complete the Site C Clean Energy Project on budget and by 2024, and to provide advice on implications for ratepayers associated with:

- proceeding with the project;
- suspending the project, while maintaining the option to resume construction until 2024; and

- terminating the project and remediating the site.

The Terms of Reference also require the BCUC to consider whether there are other resource portfolios that could provide the same level of benefits at the same or lower cost as the Site C Clean Energy Project. The inquiry began on August 9, 2017 with a preliminary report from the BCUC required within six weeks (by September 20, 2017), and a final report required within 12 weeks (by November 1, 2017).