British Columbia Hydro and Power Authority

2016/17

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, 2016 and should be read in conjunction with the MD&A presented in the 2016 Annual Service Plan Report, the 2016 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, 2016.

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, 2016 was $88 million, $28 million higher than the same period in the prior fiscal year. The increase from the prior year was primarily due to $39 million lower finance charges primarily due to lower planned short-term interest rates, lower planned interest charges on electricity purchase agreements accounted for as finance leases, and higher planned interest during construction, as well as $28 million higher domestic revenues mainly due to higher average customer rates reflecting a British Columbia Utilities Commission (BCUC) approved interim rate increase of 4 per cent effective April 1, 2016. This was partially offset by $32 million higher domestic cost of energy mainly due to higher purchases from Independent Power Producers.

- Water inflows to the system during the three months ended June 30, 2016 were 105 per cent of average, compared to 101 per cent of average in the same period in the prior fiscal year. Observed inflows to Williston and Kinbasket reservoirs were 99 per cent and 121 per cent of average, respectively, compared to 102 per cent and 125 per cent, respectively, in the prior fiscal year. The higher system inflows in fiscal 2017 were the result of an early freshet due to above normal temperatures across the province.

- Capital expenditures, before contributions in aid of construction, for the three months ended June 30, 2016 were $580 million, a $145 million increase over the same period in the prior fiscal year. BC Hydro continues to invest significantly in capital projects to refurbish its ageing infrastructure and build new assets for future growth, including the Site C Clean Energy project, John Hart Generating Station Replacement project, Ruskin Dam Safety and Powerhouse Upgrade project, and Big Bend Substation project.

($ in millions)	For the three months ended June 30 **2016**	2015	Change
Total Revenues	**$ 1,327**	$ 1,308	$ 19
Net Income	**$ 88**	$ 60	$ 28
Capital Expenditures	**$ 580**	$ 435	$ 145
GWh Sold (Domestic)	**13,459**	14,610	(1,151)

($ in millions)	***As at June 30, 2016***	*As at March 31, 2016*	Change
Total Assets	**$ 30,503**	$ 30,034	$ 469
Shareholder's Equity	**$ 4,604**	$ 4,500	$ 104
Accrued Payment to the Province	**$ -**	$ 326	$ (326)
Retained Earnings	**$ 4,485**	$ 4,397	$ 88
Debt to Equity	**80 : 20**	80 : 20	n/a
Number of Domestic Customer Accounts	**1,965,775**	1,960,555	5,220
Total Reservoir Storage (GWh)	**26,955**	16,518	10,437

CONSOLIDATED RESULTS OF OPERATIONS

These interim statements present the Company's operating 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 would 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 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.

For the three months ended June 30, 2016, transfers resulted in a net increase to regulatory accounts of $153 million, primarily due to additions to the Debt Management regulatory account, energy deferral accounts, Rate Smoothing Account, IFRS Property, Plant & Equipment account, interest on the regulatory accounts, and the Demand-Side Management account. These were partially offset by amortization of regulatory accounts.

Net income for the three months ended June 30, 2016 was $88 million, $28 million higher than the same period in the prior fiscal year net income of $60 million. The increase from the prior year was primarily due to $39 million lower finance charges primarily due to lower planned short-term interest rates, lower planned interest charges on electricity purchase agreements accounted for as finance leases, and higher planned interest during construction, as well as $28 million higher domestic revenues mainly due to higher average customer rates reflecting a BCUC approved interim rate increase of 4 per cent effective April 1, 2016. This was partially offset by $32 million higher domestic cost of energy mainly due to higher purchases from Independent Power Producers.

REVENUES

Total revenues after regulatory account transfers for the three months ended June 30, 2016 were $1,327 million, an increase of $19 million or 1 per cent compared to the same period in the prior fiscal year. The increase after regulatory account transfers was primarily due to higher planned domestic revenue mainly due to higher average customer rates and higher planned rate smoothing transfers for smoothing the rate impacts of the rate increases in the 10 Year Rates Plan, partially offset by lower planned large industrial load.

	(in millions)		(gigawatt hours)		($ per MWh)[2]	
for the three months ended June 30	**2016**	2015	**2016**	2015	**2016**	2015
Domestic						
Residential	**$ 392**	$ 392	**3,594**	3,765	**$ 109.07**	$ 104.12
Light industrial and commercial	**432**	412	**4,558**	4,485	**94.78**	91.86
Large industrial	**180**	184	**3,125**	3,343	**57.60**	55.04
Other energy sales	**90**	137	**2,182**	3,017	**41.25**	45.41
Total Domestic Revenue Before Regulatory Transfer	**1,094**	1,125	**13,459**	14,610	**81.28**	77.00
Rate smoothing and load variance regulatory transfer	**76**	17	-	-	-	-
Total Domestic	**$ 1,170**	$ 1,142	**13,459**	14,610	**$ 86.93**	$ 78.17
Trade						
Electricity - Gross	**$ 178**	$ 192	**5,881**	3,840	**$ 30.27**	$ 50.00
Less: forward electricity purchases	**(53)**	(65)	-	-	-	-
Electricity - Net	**125**	127	-	-	-	-
Gas - Gross	**70**	107	**3,801**	3,884	**18.42**	27.55
Less: forward gas purchases	**(38)**	(68)	-	-	-	-
Gas - Net	**32**	39	-	-	-	-
Total Trade[1]	**$ 157**	$ 166	**9,682**	7,724	**$ 16.22**	$ 21.49
Total	**$ 1,327**	$ 1,308	**23,141**	22,334	**$ 57.34**	$ 58.57

[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 $/MWh figures are based on total gross sales which includes physical and financial transactions whereas the volumes only include physical transactions.*

Domestic Revenues

Total domestic revenues after regulatory account transfers for the three months ended June 30, 2016 were $1,170 million, an increase of $28 million or 2 per cent compared to the same period in the prior fiscal year. Total domestic revenues before regulatory account transfers were $1,094 million, a decrease of $31 million or 3 per cent compared to the same period in the prior fiscal year. The decrease compared to the prior fiscal year was primarily due to lower other energy sales, lower large industrial revenue and lower residential revenue as a result of decreased volume, partially offset by higher average customer rates.

Other energy sales were lower as a result of less surplus energy sold (1,893 GWh), a component of other energy sales, into the market as compared to the same period in the prior fiscal year (2,716 GWh). Higher surplus sales were required in the prior year to reduce spill risk as a result of higher reservoir levels resulting from increased storage throughout the prior fall and winter due to low market prices. Surplus sales were required in the current year to move water out of Williston to reduce spill risk and facilitate the chute repairs at Gordon M. Shrum generating station.

Lower large industrial revenues were mainly due to lower load as a result of the closures of two pulp and paper mills.

Lower residential volumes were primarily driven by warmer weather and lower usage, offset by higher average customer rates.

Average customer rates were higher for all customer classes for the three months ended June 30, 2016 compared to the same period in the prior fiscal year, reflecting an average interim rate increase as approved by the BCUC of 4 per cent effective April 1, 2016.

Variances between actual and planned load are deferred to the Non-Heritage Deferral Account (NHDA) and variances between actual and planned other energy sales are deferred to the Heritage Deferral Account (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. Trade outside the Company's system is made only after ensuring domestic demand requirements are met.

Total trade revenues for the three months ended June 30, 2016 were $157 million, a decrease of $9 million or 5 per cent compared to the same period in the prior fiscal year. The decrease in revenue was primarily due to lower gas revenues primarily due to a 33 per cent decrease in the average natural gas sales price. The decrease in the average natural gas sales price was reflective of abundant North American gas supply and sustained production, mild winter temperatures and consequently higher natural gas storage levels at the beginning of the 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, 2016, operating expenses of $1,090 million were $30 million higher than in the same period in the prior fiscal year. The increase was primarily due to higher electricity purchases.

Cost of Energy

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and transmission charges 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, 2016 were $481 million, $22 million or 5 per cent higher than the same period in the prior fiscal year. The increase over the prior fiscal year was primarily due to higher volume of purchases from Independent Power Producers.

for the three months ended June 30	*(in millions)* 2016	2015	*(gigawatt hours)* 2016	2015	*($ per MWh)* [2] 2016	2015
Domestic						
Water rental payments (hydro generation)[1]	**$ 88**	$ 80	**10,176**	12,298	**$ 8.88**	$ 6.68
Purchases from Independent Power Producers	**292**	272	**4,022**	3,735	**72.60**	72.81
Other electricity purchases - Domestic	**-**	-	**11**	5	**-**	-
Gas for thermal generation	**6**	7	**41**	43	**146.34**	159.37
Transmission charges and other expenses	**5**	5	**25**	24	**-**	-
Allocation from (to) trade energy	**-**	(6)	**44**	(243)	**15.90**	24.83
Total Domestic Cost of Energy Before Regulatory Transfers	**391**	358	**14,319**	15,862	**27.31**	22.57
Domestic cost of energy regulatory transfers	**(20)**	(19)	**-**	-	**-**	-
Total Domestic	**$ 371**	$ 339	**14,319**	15,862	**$ 25.91**	$ 21.39
Trade						
Electricity - Gross	**$ 87**	$ 93	**5,919**	3,543	**$ 14.70**	$ 26.25
Less: forward electricity purchases	**(53)**	(65)	**-**	-	**-**	-
Electricity - Net	**34**	28	**-**	-	**-**	-
Remarketed gas - Gross	**50**	99	**3,900**	3,973	**12.82**	24.92
Less: forward gas purchases	**(38)**	(68)	**-**	-	**-**	-
Remarketed gas - Net	**12**	31	**-**	-	**-**	-
Transmission charges and other expenses	**65**	51	**-**	-	**-**	-
Allocation (to) from domestic energy	**0**	6	**(44)**	243	**15.90**	24.83
Total Trade Cost of Energy Before Regulatory Transfers	**111**	116	**9,775**	7,759	**16.75**	23.29
Trade net margin regulatory transfer	**(1)**	4	**-**	-	**-**	-
Total Trade	**110**	120	**9,775**	7,759	**16.64**	23.83
Total Energy Costs	**$ 481**	$ 459	**24,094**	23,621	**$ 22.15**	$ 22.17

[1] *Total GWh is net of storage exchange.*

[2] *Total cost per MWh includes other electricity purchases at gross cost.*

Domestic Energy Costs

Total domestic energy costs after regulatory transfers for the three months ended June 30, 2016 were $371 million, $32 million or 9 per cent higher than the same period in the prior fiscal year. Total domestic energy costs before regulatory transfers for the three months ended June 30, 2016 were $391 million, $33 million or 9 per cent higher than the same period in the prior fiscal year. The increase in costs, before regulatory transfers, was primarily due to higher purchases from Independent Power Producers, driven by more Independent Power Producers in operation and an early freshet, which resulted in more energy being delivered from hydro resources. The increase was also due to higher water rental payments. Water rental payments are based on the previous calendar year's generation volumes and in calendar year 2015 there was more hydro generated than in calendar year 2014, resulting in higher water rental payments in the current year.

Variances between actual and planned domestic cost of energy are transferred to the HDA and NHDA.

Trade Energy Costs

Total trade energy costs after regulatory transfers for the three months ended June 30, 2016 were $110 million, $10 million or 8 per cent lower than the same period in the prior fiscal year. Total trade energy costs before regulatory account transfers for the three months ended June 30, 2016 were $111 million, a decrease of $5 million or 4 per cent compared with the same period in the prior fiscal year. The decrease, before regulatory transfers, was primarily due to lower gas costs as a result of a 49 per cent decrease in the average natural gas purchase price. The decrease in the average natural gas purchase price was reflective of abundant North American gas supply and sustained production, mild winter temperatures and consequently higher natural gas storage levels at the beginning of the year.

Variances between actual and planned trade cost of energy are transferred to the TIDA.

Water Inflows

Water inflows (energy equivalent) to BC Hydro's system during the three months ended June 30, 2016 were 105 per cent of average, compared to 101 per cent of average in the same period in the prior fiscal year. The higher inflows in fiscal 2017 were the result of an early freshet due to above normal temperatures across the province. Observed inflows to Williston and Kinbasket reservoirs were 99 per cent and 121 per cent of average, respectively, compared to 102 per cent and 125 per cent, respectively, in the prior fiscal year.

The Williston and Kinbasket reservoirs have been managed such that system energy storage on June 30, 2016 was 25,000 GWh, or 2,300 GWh above the 10 year historic average. This was 600 GWh lower than the system energy storage of 25,600 GWh recorded one year earlier. The Williston and Kinbasket reservoir energy contents were 16,500 GWh (1,000 GWh above the 10 year historic average) and 8,500 GWh (1,300 GWh above the 10 year historic average), respectively, with Williston 200 GWh lower than the prior fiscal year and Kinbasket 400 GWh lower than the prior fiscal year. The relative imbalance between the Williston and Kinbasket reservoir operations during this period was due to running Gordon M. Shrum/Peace Canyon generating stations on first preference to reduce the spill risk at Williston. The above average energy content in system storage at June 30, 2016 was a result of a combination of above average energy content at the start of the fiscal year and above average inflows.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the three months ended June 30, 2016 were $139 million, $6 million lower than the same period in the prior fiscal year primarily due to lower post-employment benefits mainly due to lower current service pension costs.

Materials and External Services

Expenditures on materials and external services for the three months ended June 30, 2016 were $149 million, comparable to materials and external services of $145 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 (PP&E), amortization of intangible assets, and the amortization of certain regulatory assets and liabilities. For the three months ended June 30, 2016, amortization and depreciation expense was $300 million, comparable to amortization and depreciation expense of $304 million in the same period in the prior fiscal year.

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, 2016 were $65 million, $10 million higher than the same period in the prior fiscal year primarily related to other costs mainly due to higher costs incurred related to asset disposals and retirements in the current period.

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 fiscal 2013, the ongoing impact of this change is being smoothed into 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, 1/10th 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, 2016 were $44 million, comparable to capitalized costs of $48 million in the same period in the prior fiscal year.

FINANCE CHARGES

Finance charges for the three months ended June 30, 2016 were $149 million, $39 million or 21 per cent lower than the same period in the prior fiscal year. The decrease was primarily due to lower planned short-term interest rates, lower planned interest charges on electricity purchase agreements accounted for as finance leases, and higher planned interest during construction. This decrease was partially offset by higher planned volume of long-term debt borrowings.

REGULATORY TRANSFERS

The Company has established various regulatory accounts with the approval of the BCUC. 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* **2016**	2015
Energy Deferral Accounts		
Heritage Deferral Account	**$ (18)**	$ (83)
Non-Heritage Deferral Account	**66**	85
Trade Income Deferral Account	**1**	(1)
	49	1
Forecast Variance Accounts		
Total Finance Charges	**(1)**	(37)
Rate Smoothing Account	**48**	27
Non-Current Pension Cost	**2**	-
Debt Management	**80**	-
Other	**(2)**	(8)
	127	(18)
Capital-Like Accounts		
Demand-Side Management	**16**	32
Smart Metering & Infrastructure	**-**	3
IFRS Property, Plant & Equipment	**28**	34
	44	69
Non-Cash Accounts		
Environmental Provisions & Costs	**8**	(9)
First Nations Provisions & Costs	**1**	-
Other	**-**	1
	9	(8)
Amortization of regulatory accounts	**(96)**	(110)
Interest on regulatory accounts	**20**	17
Net change in regulatory accounts	**$ 153**	$ (49)

For the three months ended June 30, 2016, net additions to the Company's regulatory accounts after interest and amortization were $153 million compared to prior year net reductions of $49 million. The net regulatory asset balance as at June 30, 2016 was $6,061 million compared to $5,908 million as at March 31, 2016.

Net additions to the regulatory accounts during the three months ended June 30, 2016 included:

- Increases of $80 million to the Debt Management regulatory account as a result of a decrease in interest rates since BC Hydro's initial interest rate hedges on future debt issuances were executed. If interest rates remain the same, BC Hydro will still be able to issue the hedged future debt at lower interest rates than forecast in the Fiscal 2017-2019 Revenue Requirements Application;

- Increases of $49 million to the energy deferral accounts primarily due to lower domestic revenues, higher purchases from Independent Power Producers, partially offset by higher surplus sales;

- Increases of $48 million to the Rate Smoothing Account to smooth the rate impacts over the 10 Year Rates Plan;

- Transfers of $28 million 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;

- Interest on regulatory accounts of $20 million; and

- Expenditures of $16 million on planned Demand-Side Management projects, which support energy conservation.

These net additions were partially offset by net amortization of $96 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 25 of 27 regulatory accounts in use or with balances at June 30, 2016 in rates over various periods, which represent approximately 87 per cent of the total net regulatory 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 Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20.

No payment has been accrued as at June 30, 2016 as the Company's debt to equity ratio was at the 80:20 cap prior to the calculation of the Payment. As at March 31, 2016, $326 million was accrued and the Payment to the Province was made in June 2016.

On July 28, 2016, the Province issued Order in Council No. 589, which amended the Special Directive. This amendment states that BC Hydro must make a payment to the Province of an amount no less than $259 million by June 30, 2017, as it relates to fiscal 2017. The Special Directive states that for fiscal 2018 and subsequent years, the payment to the Province 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.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the three months ended June 30, 2016 was $44 million, compared with cash flow provided by operating activities of $168 million in the same period in the prior fiscal year. The decrease was mainly due to lower domestic revenue primarily due to lower domestic load, as well as higher purchases from Independent Power Producers.

The long-term debt balance net of sinking funds at June 30, 2016 was $18,852 million, compared with $18,046 million at March 31, 2016. The increase was mainly as a result of an increase in revolving borrowings of $617 million and a long-term bond issuance totaling $201 million ($200 million par value). Long-term debt increased primarily to fund capital expenditures.

CAPITAL EXPENDITURES

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

		For the three months ended June 30		
(in millions)		**2016**		2015
Transmission lines and substations replacements and expansion	**$**	**124**	$	177
Generation replacements and expansion		**134**		110
Distribution system improvements and expansion		**115**		92
General, including technology, vehicles and buildings		**52**		36
Site C Clean Energy project		**155**		20
Total Capital Expenditures	**$**	**580**	$	435

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

Transmission lines and substation capital expenditures includes expenditures on the Big Bend Substation project, and the Transmission Wood Structure and Framing Replacement program.

Generation capital expenditures include expenditures for John Hart Generating Station Replacement project, Ruskin Dam Safety and Powerhouse Upgrade project, Upper Columbia Capacity Additions at Mica – Units 5 & 6 project, and Gordon M. Shrum Spillway Chute Interim Upgrade 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 technology projects, building development programs, and vehicles.

Site C Clean Energy project expenditures include expenditures for worker accommodations, site preparation, clearing, and the commencement of 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 achieve an annual rate of return on deemed equity (ROE).

10 Year Rates Plan

In November 2013, the Government announced a 10 Year Rates Plan for BC Hydro. On March 6, 2014, the Government issued Directions No. 6 and 7 to the BCUC to implement the 10 Year Rates Plan. BC Hydro rate increases for fiscal 2017, fiscal 2018, and fiscal 2019 are subject to BCUC review but are capped at 4.0 per cent, 3.5 per cent, and 3.0 per cent, respectively, pursuant to Direction No. 7. The BCUC will also set the rates for the final five years of the plan. Furthermore, the Deferral Account Rate Rider will remain at 5 per cent for fiscal 2016 and future years.

Fiscal 2017-2019 Revenue Requirements Application

On July 28, 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. BC Hydro had filed an Application with the BCUC in February 2016 for an interim rate increase of 4.0 per cent for fiscal 2017. The BCUC approved BC Hydro's Application for fiscal 2017 interim rate increase of 4.0 per cent on March 30, 2016 via Order No. G-46-16.

2015 Rate Design Application

In September 2015, BC Hydro filed Module 1 of its 2015 Rate Design Application with the BCUC. Among the various approvals sought in Module 1 of the 2015 Rate Design Application, BC Hydro is seeking approval to simplify its commercial rates, retain the inclining block structure for residential customers and introduce a new rate for transmission service customers that would provide market pricing during the freshet period (May to July) for incremental consumption. The BC Old Age Pensioners Association and the Commercial Energy Consumers submitted evidence to the BCUC in May 2016. The BC Old Age Pensioners Association evidence included a proposal for a low income rate. BC Hydro provided rebuttal evidence against both submissions to the BCUC on July 6, 2016, including arguments against the low income rate proposal. The BCUC has scheduled an oral hearing for August 16-18 and August 23-24, 2016. Changes in rate design are designed to be revenue neutral to BC Hydro.

Inquiry of Expenditures in the Adoption of the SAP Platform

BC Hydro filed a Consolidated Information Filing on June 29, 2016 in compliance with BCUC Order No. G-81-16 providing information pertaining to BC Hydro's investment in the SAP technology platform. The filing provided background information on BC Hydro's enterprise resource planning investments from the 1990s to present day, along with forecast SAP-related capital expenditures out until fiscal 2026. The BCUC and Interveners issued Information Requests on August 4, 2016, with BC Hydro's responses due on September 9, 2016. The BCUC has scheduled a Procedural Conference in October 2016.

Capital Expenditures and Projects Review

The BCUC issued Order No. G-58-16 in April 2016 to commence a review of the regulatory oversight of BC Hydro's capital expenditures and projects. The scope of the review will include (but is not limited to) examining BC Hydro's Capital Project Filing Guidelines, expenditure thresholds, and definitions as to what constitutes a capital project. The BCUC will be holding the first procedural conference on the review on October 13, 2016.

Mandatory Reliability Standards Assessment Report No. 9

BC Hydro filed on April 28, 2016 its ninth Assessment Report on Mandatory Reliability Standards to the BCUC. The report presents BC Hydro's assessment of the reliability impacts, suitability, standard applicability and potential costs of adopting 17 new and revised reliability standards for the bulk electric system in B.C. The BCUC sought public comment on the Assessment Report, as provided by two intervener groups in May 2016. BC Hydro issued its reply to these public comments on June 9, 2016. The BCUC will be issuing a decision on the Assessment Report in the summer.

RISK MANAGEMENT

BC Hydro is exposed to numerous risks, which can result in safety, environmental, financial, reliability and reputational impacts. The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income is mitigated through the use of 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 F2017-2019 Revenue Requirements Application includes information regarding existing and proposed recovery mechanisms regarding its regulatory accounts.

Significant Financial Risks

The largest sources of variability in BC Hydro's financial performance are typically domestic and trade revenue and cost of energy. Both revenues and cost of energy are influenced by several elements, which generally fall into the following four categories: generation available from BC Hydro-dispatched hydro plants, domestic demand for electricity, energy market prices, and deliveries from electricity purchase agreements. 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, 2016. 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 2016 forecast net income for fiscal 2017 at $692 million.

The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, domestic sales load, market prices for electricity and natural gas, weather, temperatures and interest 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 2017 assumed average water inflows (100 per cent of average), domestic sales of 56,692 GWh, average market energy prices of US $24.15/MWh, short-term interest rates of 0.68 per cent and a US dollar exchange rate of US $0.7646.

BC Hydro filed an updated forecast with the Province in August 2016. The net income forecast for fiscal 2017 decreased to $685 million due to a decrease in forecast assets-in-service in fiscal 2017 which impacts rate base, and therefore the forecast net income calculation. The net income forecast is the same as the net income forecast included in the Fiscal 2017-2019 Revenue Requirements Application.

On July 28, 2016, the Government issued Order in Council No. 590, which amends Direction No. 7 to the BCUC. This amendment states that BC Hydro's annual rate of return on deemed equity shall be an amount necessary to yield a net income of $684 million for fiscal 2017, $698 million for fiscal 2018, and $712 million for fiscal 2019 and subsequent fiscal years.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(in millions)		*For the three months ended June 30* **2016**		2015
Revenues				
Domestic	**$**	**1,170**	$	1,142
Trade		**157**		166
		1,327		1,308
Expenses				
Operating expenses (Note 3)		**1,090**		1,060
Finance charges (Note 4)		**149**		188
Net Income		**88**		60
OTHER COMPREHENSIVE INCOME (LOSS)				
Items Reclassified Subsequently to Net Income				
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 13)		**7**		(20)
Reclassification to income of derivatives designated as cash flow hedges (Note 13)		**8**		16
Foreign currency translation gains (losses)		**1**		(1)
Other Comprehensive Income (Loss)		**16**		(5)
Total Comprehensive Income	**$**	**104**	$	55

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* 2016**	*As at March 31* 2016
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 34**	$ 44
Accounts receivable and accrued revenue	**559**	669
Inventories (Note 6)	**187**	155
Prepaid expenses	**215**	202
Current portion of derivative financial instrument assets (Note 13)	**109**	137
	1,104	1,207
Non-Current Assets		
Property, plant and equipment (Note 7)	**21,764**	21,385
Intangible assets (Note 7)	**609**	609
Regulatory assets (Note 8)	**6,467**	6,324
Derivative financial instrument assets (Note 13)	**97**	92
Other non-current assets (Note 9)	**462**	417
	29,399	28,827
	$ 30,503	$ 30,034
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 1,276**	$ 1,816
Current portion of long-term debt (Note 10)	**3,033**	2,376
Current portion of derivative financial instrument liabilities (Note 13)	**154**	143
	4,463	4,335
Non-Current Liabilities		
Long-term debt (Note 10)	**15,988**	15,837
Regulatory liabilities (Note 8)	**406**	416
Derivative financial instrument liabilities (Note 13)	**47**	27
Contributions in aid of construction	**1,709**	1,669
Post-employment benefits (Note 12)	**1,660**	1,657
Other non-current liabilities (Note 14)	**1,626**	1,593
	21,436	21,199
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**4,485**	4,397
Accumulated other comprehensive income	**59**	43
	4,604	4,500
	$ 30,503	$ 30,034

Commitments (Note 7)

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

Approved on behalf of the Board:

W. J. Brad Bennett, O.B.C.
Chair, Board of Directors

Tracy Redies
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 (Loss)	Contributed Surplus	Retained Earnings	Total
Balance, April 1, 2015	$ 67	$ (25)	$ 42	$ 60	$ 4,068	$ 4,170
Comprehensive Income (Loss)	(1)	(4)	(5)	-	60	55
Balance, June 30, 2015	$ 66	$ (29)	$ 37	$ 60	$ 4,128	$ 4,225
Balance, April 1, 2016	$ 77	$ (34)	$ 43	$ 60	$ 4,397	$ 4,500
Comprehensive Income	1	15	16	-	88	104
Balance, June 30, 2016	$ 78	$ (19)	$ 59	$ 60	$ 4,485	$ 4,604

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* **2016**	2015
Operating Activities		
Net income	**$ 88**	$ 60
Regulatory account transfers (Note 8)	**(249)**	(61)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 8)	**96**	110
Amortization and depreciation expense (Note 5)	**195**	186
Unrealized losses on mark-to-market	**61**	24
Employee benefit plan expenses	**29**	28
Interest accrual	**185**	171
Other items	**22**	11
	427	529
Changes in:		
Accounts receivable and accrued revenue	**96**	27
Prepaid expenses	**(14)**	(11)
Inventories	**(32)**	(26)
Accounts payable, accrued liabilities and other non-current liabilities	**(160)**	(135)
Contributions in aid of construction	**26**	47
Other non-current assets	**(7)**	-
	(91)	(98)
Interest paid	**(292)**	(263)
Cash provided by operating activities	**44**	168
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(543)**	(471)
Cash used in investing activities	**(543)**	(471)
Financing Activities		
Long-term debt issued (Note 10)	**201**	893
Receipt of revolving borrowings	**2,677**	1,717
Repayment of revolving borrowings	**(2,059)**	(2,016)
Payment to the Province (Note 11)	**(326)**	(264)
Other items	**(4)**	(5)
Cash provided by financing activities	**489**	325
Increase (decrease) in cash and cash equivalents	**(10)**	22
Cash and cash equivalents, beginning of period	**44**	39
Cash and cash equivalents, end of period	**$ 34**	$ 61

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

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE MONTHS ENDED JUNE 30, 2016

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 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 condensed consolidated 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 condensed consolidated 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 condensed consolidated 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 condensed consolidated interim financial statements with respect to BC Hydro's regulatory accounts is described in Note 8.

These condensed consolidated 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 2016 Annual Service Plan Report. Effective April 1, 2016, BC Hydro adopted amendments to various accounting standards that did not have a significant impact on these condensed consolidated interim financial statements. These condensed consolidated interim financial statements should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2016 Annual Service Plan Report.

These condensed consolidated interim financial statements were approved on behalf of the Board of Directors on August 22, 2016.

NOTE 3: OPERATING EXPENSES

(in millions)		*For the three months ended June 30* **2016**		2015
Electricity and gas purchases	**$**	**350**	$	334
Water rentals		**90**		91
Transmission charges		**41**		34
Personnel expenses		**139**		145
Materials and external services		**149**		145
Amortization and depreciation (Note 5)		**300**		304
Grants, taxes and other costs		**65**		55
Less: Capitalized costs		**(44)**		(48)
	$	**1,090**	$	1,060

NOTE 4: FINANCE CHARGES

(in millions)		*For the three months ended June 30* **2016**		2015
Interest on long-term debt	**$**	**186**	$	193
Interest on finance lease liabilities		**5**		23
Less: Other recoveries		**(23)**		(13)
Capitalized interest		**(19)**		(15)
	$	**149**	$	188

NOTE 5: AMORTIZATION AND DEPRECIATION

(in millions)		*For the three months ended June 30* **2016**		2015
Depreciation of property, plant and equipment	**$**	**177**	$	170
Amortization of intangible assets		**18**		16
Amortization of regulatory accounts		**105**		118
	$	**300**	$	304

NOTE 6: INVENTORIES

(in millions)	***As at June 30* 2016**	*As at March 31* 2016
Materials and supplies	**$ 117**	$ 119
Natural gas trading inventories	**70**	36
	$ 187	$ 155

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, 2016 were $580 million (2015 - $435 million).

As of June 30, 2016, the Company has contractual commitments to spend $3,556 million on major property, plant and equipment projects (for individual projects greater than $50 million).

NOTE 8: RATE REGULATION

BC Hydro filed an interim F2017 Revenue Requirement Application (Interim RRA) on February 26, 2016 requesting an interim rate increase of 4.0 per cent effective April 1, 2016. The rate increase is consistent with the rate cap for fiscal 2017 set out in the 10 Year Rates Plan. On March 22, 2016, the BCUC approved an interim fiscal 2017 rate increase of 4.0 per cent. At the time of filing the Interim RRA, BC Hydro identified that recent developments would have a material impact on the projections used in its revenue requirements for fiscal 2017 to fiscal 2019 and that BC Hydro would submit a revised revenue requirement covering fiscal 2017 to fiscal 2019 in the summer of 2016. BC Hydro filed its revised F2017-2019 Revenue Requirements Application (F2017-F2019 RRA), including a revised fiscal 2017 revenue requirement, on July 28, 2016. The rate increases requested were 4.0 per cent, 3.5 per cent, and 3.0 per cent for fiscal 2017, fiscal 2018, and fiscal 2019, respectively, consistent with the rate caps set out in the 10 Year Rates Plan.

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, 2016, the impact of regulatory accounting has resulted in a net increase to total comprehensive income of $153 million (2015 - $49 million decrease). 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, 2016 are based on the F2017-F2019 RRA, which remains subject to approval by the BCUC.

(in millions)	*April 1 2016*	*Addition (Reduction)*	*Interest*	*Amortization*	*Net Change*	*June 30 2016*
Regulatory Assets						
Non-Heritage Deferral Account	$ 917	$ 66	$ 9	$ (39)	$ 36	$ 953
Trade Income Deferral Account	249	1	3	(11)	(7)	242
Demand-Side Management	908	16	-	(22)	(6)	902
First Nations Provisions & Costs	541	1	2	(8)	(5)	536
Non-Current Pension Cost	691	2	-	(15)	(13)	678
Site C	436	-	4	-	4	440
CIA Amortization	92	-	-	-	-	92
Environmental Provisions & Costs	358	8	-	(9)	(1)	357
Smart Metering & Infrastructure	283	-	3	(8)	(5)	278
IFRS Pension	612	-	-	(10)	(10)	602
IFRS Property, Plant & Equipment	872	28	-	(6)	22	894
Rate Smoothing Account	287	48	-	-	48	335
Debt Management	-	80	-	-	80	80
Other Regulatory Accounts	78	4	-	(4)	-	78
Total Regulatory Assets	6,324	254	21	(132)	143	6,467
Regulatory Liabilities						
Heritage Deferral Account	24	18	1	(1)	18	42
Future Removal & Site Restoration Costs	9	-	-	(9)	(9)	-
Foreign Exchange Gains and Losses	69	-	-	-	-	69
Total Finance Charges	305	1	-	(25)	(24)	281
Other Regulatory Accounts	9	6	-	(1)	5	14
Total Regulatory Liabilities	416	25	1	(36)	(10)	406
Net Regulatory Asset	$ 5,908	$ 229	$ 20	$ (96)	$ 153	$ 6,061

NOTE 9: OTHER NON-CURRENT ASSETS

(in millions)	***As at June 30*** **2016**	*As at March 31* 2016
Non-current receivables	**$ 207**	$ 171
Sinking funds	**169**	167
Other	**86**	79
	$ 462	$ 417

Included in the non-current receivables balance is a $153 million receivable (March 31, 2016 - $152 million) for contributions in aid of the construction of the Northwest Transmission Line (NTL) and a $32 million receivable (March 31, 2016 - $8 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, 2016, the outstanding amount under the borrowing program was $2,993 million (March 31, 2016 - $2,376 million).

In the three months ended June 30, 2016, the Company issued bonds with net proceeds of $201 million (2015 - $893 million) and a par value of $200 million (2015 - $900 million), a weighted average effective interest rate of 2.2 per cent (2015 - 2.8 per cent) and a weighted average term to maturity of 10.1 years (2015 - 25.4 years).

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 and a limit on the Payment to the Province if it would cause the debt to equity ratio to exceed 80:20.

The Company monitors its capital structure on the basis of its debt to equity ratio. 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.

During the three months ended June 30, 2016, there were no changes in the approach to capital management.

The debt to equity ratio at June 30, 2016, and March 31, 2016 was as follows:

(in millions)	***As at June 30* 2016**	*As at March 31* 2016
Total debt, net of sinking funds	**$ 18,852**	$ 18,046
Less: Cash and cash equivalents	**(34)**	(44)
Net Debt	**$ 18,818**	$ 18,002
Retained earnings	**$ 4,485**	$ 4,397
Contributed surplus	**60**	60
Accumulated other comprehensive income	**59**	43
Total Equity	**$ 4,604**	$ 4,500
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 Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20.

No Payment has been accrued as at June 30, 2016 as the Company's debt to equity ratio is at the 80:20 cap prior to the calculation of the Payment. As at March 31, 2016, $326 million was accrued (included in accounts payable and accrued liabilities) and the Payment to the Province was made in June 2016.

On July 28, 2016, the Province issued Order in Council No. 589, which states that BC Hydro must make a Payment to the Province of an amount no less than $259 million by June 30, 2017, as it relates to fiscal 2017. The Special Directive states that for fiscal 2018 and subsequent years, the payment to the Province 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.

NOTE 12: POST-EMPLOYMENT BENEFITS

The expense recognized in the Statements of Comprehensive Income 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, 2016 was $42 million (2015 - $43 million).

Company contributions to the registered defined benefit pension plans for the three months ended June 30, 2016 were $14 million (2015 - $16 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, 2016 and 2015.

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, 2016 and March 31, 2016. The non-derivative financial instruments, where carrying value differs from fair value, would be classified as Level 2 of the fair value hierarchy.

	June 30, 2016		March 31, 2016	
(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	**$ 8**	**$ 8**	$ 11	$ 11
Loans and Receivables:				
Accounts receivable and accrued revenue	**559**	**559**	669	669
Non-current receivables	**207**	**212**	171	171
Cash	**26**	**26**	33	33
Held to Maturity:				
Sinking funds – US	**169**	**199**	167	194
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**(1,276)**	**(1,276)**	(1,816)	(1,816)
Revolving borrowings - CAD	**(1,923)**	**(1,923)**	(1,605)	(1,605)
Revolving borrowings - US	**(1,070)**	**(1,070)**	(771)	(771)
Long-term debt (including current portion due in one year)	**(16,028)**	**(19,708)**	(15,837)	(18,684)
First Nations liabilities (non-current portion)	**(377)**	**(630)**	(378)	(547)
Finance lease obligations (non-current portion)	**(214)**	**(214)**	(219)	(219)
Other liabilities	**(166)**	**(174)**	(147)	(153)

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

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

(in millions)	**June 30, 2016 Fair Value**	March 31, 2016 Fair Value
Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ 71**	$ 57
Foreign currency contracts (cash flow hedges for €EURO denominated long-term debt)	**(12)**	(5)
	59	52
Non-Designated Derivative Instruments:		
Interest rate contracts	**(80)**	-
Foreign currency contracts	**7**	(34)
Commodity derivatives	**19**	41
	(54)	7
Net asset	**$ 5**	$ 59

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 statements of financial position as follows:

(in millions)	**June 30, 2016**	March 31, 2016
Current portion of derivative financial instrument assets	**$ 109**	$ 137
Current portion of derivative financial instrument liabilities	**(154)**	(143)
Derivative financial instrument assets, non-current	**97**	92
Derivative financial instrument liabilities, non-current	**(47)**	(27)
Net asset	**$ 5**	$ 59

For designated cash flow hedges for the three months ended June 30, 2016, a gain of $7 million (2015 - $20 million loss) was recognized in other comprehensive income. For the three months ended June 30, 2016, $8 million (2015 - $16 million) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange gains (2015 - gains) recorded in the year.

For the three months ended June 30, 2016, there was an $80 million decrease (2015 - $nil, no interest rate contracts) in the fair value of interest rate contracts with an aggregate notional principal of $2.2 billion used to economically hedge the interest rates on future debt issuances. The change in fair value was recognized in finance charges and then transferred to the Debt Management regulatory account.

For the three months ended June 30, 2016, a gain of $3 million (2015 - $14 million loss) was recognized in finance charges with respect to foreign currency contracts for U.S. short-term borrowings. These economic hedges offset $3 million of foreign exchange revaluation losses (2015 - $13 million gains) recorded with respect to U.S. short-term borrowings for the three months ended June 30, 2016.

A net loss of $30 million (2015 - $4 million loss) was recorded in trade revenue for the three months ended June 30, 2016 with respect to commodity derivatives.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)	*For the three months ended June 30* **2016**	2015
Deferred inception loss, beginning of the period	**$ 48**	$ 70
New transactions	**(4)**	(1)
Amortization	**(1)**	(7)
Deferred inception loss, end of the period	**$ 43**	$ 62

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, 2016 and March 31, 2016:

As at June 30, 2016 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 8	$ -	$ -	$ 8
Derivatives designated as hedges	-	71	-	71
Derivatives not designated as hedges	64	35	36	135
Total financial assets carried at fair value	$ 72	$ 106	$ 36	$ 214

As at June 30, 2016 *(in millions)*	Level 1	Level 2	Level 3	Total
Derivatives designated as hedges	$ -	$ (12)	$ -	$ (12)
Derivatives not designated as hedges	(78)	(97)	(14)	(189)
Total financial liabilities carried at fair value	$ (78)	$ (109)	$ (14)	$ (201)

As at March 31, 2016 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 11	$ -	$ -	$ 11
Derivatives designated as hedges	-	62	-	62
Derivatives not designated as hedges	75	30	62	167
Total financial assets carried at fair value	$ 86	$ 92	$ 62	$ 240

As at March 31, 2016 *(in millions)*	Level 1	Level 2	Level 3	Total
Derivatives designated as hedges	$ -	$ (10)	$ -	$ (10)
Derivatives not designated as hedges	(108)	(46)	(6)	(160)
Total financial liabilities carried at fair value	$ (108)	$ (56)	$ (6)	$ (170)

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 Levels 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, 2016 and 2015:

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

(in millions)	
Balance at April 1, 2015	**$ 39**
Net loss recognized	(12)
New transactions	(1)
Existing transactions settled	5
Balance at June 30, 2015	**$ 31**

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, 2016, unrealized losses of $28 million (2015 - $16 million loss) were recognized on Level 3 derivative commodity assets held at June 30, 2016. During the three months ended June 30, 2016, unrealized losses of $4 million (2015 - $9 million gain) were recognized on Level 3 derivative commodity liabilities held at June 30, 2016. 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 2016***	*As at March 31* 2016
Provisions		
Environmental liabilities	**$ 393**	$ 390
Decommissioning obligations	**57**	56
Other	**10**	10
	460	456
First Nations liabilities	**396**	409
Finance lease obligations	**235**	240
Other liabilities	**166**	147
Deferred revenue - Skagit River Agreement	**472**	463
	1,729	1,715
Less: Current portion, included in accounts payable and accrued liabilities	**(103)**	(122)
	$ 1,626	$ 1,593

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.