British Columbia Hydro and Power Authority

2015/16

THIRD 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 and nine months ended December 31, 2015 and should be read in conjunction with the MD&A presented in the 2015 Annual Report, the 2015 Annual Consolidated Financial Statements of the Company, and the Unaudited Condensed Consolidated Interim Financial Statements and related notes of the Company for the three and nine months ended December 31, 2015.

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 December 31, 2015 was $217 million, $14 million higher than the same period in the prior fiscal year primarily due to higher domestic revenues and lower operating expenses, partially offset by higher finance charges. Net income for the nine months ended December 31, 2015 was $350 million, $18 million lower than the same period in the prior fiscal year primarily due to lower trade revenues and higher finance charges, partially offset by lower operating expenses and higher domestic revenues.

- Water inflows to the system for the nine months ended December 31, 2015 were 97 per cent of average, compared to 98 per cent of average in the same period in the prior fiscal year. The system inflow forecast for fiscal 2016 is 97 per cent of average, compared to a system inflow of 102 per cent of average in fiscal 2015.

- Capital expenditures for the three and nine months ended December 31, 2015 were $594 million and $1,567 million, respectively. BC Hydro continues to invest significantly in capital projects to refurbish its ageing infrastructure and build new assets for future growth, including John Hart Generating Station Replacement, Site C Clean Energy project, Interior to Lower Mainland Transmission project, Dawson Creek/Chetwynd Area Transmission project, Ruskin Dam Safety and Powerhouse Upgrade project, and the Upper Columbia Capacity Additions at Mica – Units 5 & 6 project.

	For the three months ended December 31			*For the nine months ended December 31*		
	2015	2014	Change	**2015**	2014	Change
Net Income *(in millions)*	**$ 217**	$ 203	$ 14	**$ 350**	$ 368	$ (18)
GWh Sold (Domestic)	**14,229**	13,670	559	**42,756**	37,534	5,222

($ in millions)	***As at December 31, 2015***	*As at March 31, 2015*	Change
Total Assets	**$ 29,164**	$ 27,753	$ 1,411
Retained Earnings	**$ 4,386**	$ 4,068	$ 318
Accrued Payment to the Province	**$ 32**	$ 264	$ (232)
Debt to Equity	**80 : 20**	80 : 20	N/A
Number of Domestic Customer Accounts	**1,955,189**	1,935,068	20,121
Total Reservoir Storage (GWh)	**24,244**	19,565	4,679

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 plus ASC 980 to reflect the rate-regulated environment in which the Company operates. These principles allow for the deferral of costs and recoveries that under IFRS would otherwise be recorded as expenses or income in the current accounting period. 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 British Columbia Utilities Commission (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.

For the three and nine months ended December 31, 2015, transfers resulted in a net increase to regulatory accounts of $131 million and $131 million, respectively, primarily due to additions to the energy deferral accounts, additions for the phasing in of the rate impact of the reduction in the amount of overhead eligible for capitalization under IFRS, demand-side management program expenditures (DSM), increases to the Rate Smoothing regulatory account as part of the 10 year rate plan, and interest on the regulatory accounts. These were partially offset by amortization of regulatory accounts and additions to the Finance Charges regulatory liability account.

Net income for the three months ended December 31, 2015 was $217 million, $14 million higher than the same period in the prior fiscal year primarily due to higher domestic revenues and lower operating expenses, partially offset by higher finance charges. Net income for the nine months ended December 31, 2015 was $350 million, $18 million lower than the same period in the prior fiscal year primarily due to lower trade revenues and higher finance charges, partially offset by lower operating expenses, and higher domestic revenues.

REVENUES

Total revenues after regulatory account transfers for the three months ended December 31, 2015 were $1,503 million, an increase of $22 million or 1 per cent compared to the same period in the prior fiscal year. The increase was primarily due to higher average customer rates and higher surplus energy sales, partially offset by lower trade revenues.

Total revenues after regulatory account transfers for the nine months ended December 31, 2015 were $4,073 million, a decrease of $120 million or 3 per cent compared to the same period in the prior fiscal year. The decrease for the nine months ended December 31, 2015 compared to the same period in the prior year was primarily due to lower trade revenues, partially offset by higher domestic revenues due to higher average customer rates and higher surplus energy sales.

For the three months ended December 31	*(in millions)* **2015**	2014	*(gigawatt hours)* **2015**	2014	*($ per MWh)*[2] **2015**	2014
Domestic						
Residential	**$ 539**	$ 495	**5,029**	4,895	**$ 107.18**	$101.12
Light industrial and commercial	**427**	405	**4,660**	4,690	**91.63**	86.35
Large industrial	**190**	184	**3,493**	3,551	**54.39**	51.82
Other energy sales	**91**	74	**1,047**	534	**86.91**	138.58
Total Domestic Revenue Before Regulatory Transfer	**1,247**	1,158	**14,229**	13,670	**87.64**	84.71
Rate smoothing and load variance regulatory transfer	**105**	132	-	-	-	-
Total Domestic	**$ 1,352**	$ 1,290	**14,229**	13,670	**$ 95.02**	$ 94.37
Trade						
Electricity - Gross	**$ 120**	$ 190	**3,436**	4,022	**$ 34.92**	$ 47.24
Less: forward electricity purchases	**(33)**	(40)	-	-	-	-
Electricity - Net	**87**	150	-	-	-	-
Gas - Gross	**132**	220	**4,327**	5,098	**30.51**	43.15
Less: forward gas purchases	**(68)**	(179)	-	-	-	-
Gas - Net	**64**	41	-	-	-	-
Total Trade[1]	**$ 151**	$ 191	**7,763**	9,120	**$ 19.45**	$ 20.94
Total	**$ 1,503**	$ 1,481	**21,992**	22,790	**$ 68.34**	$ 64.98

For the nine months ended December 31	*(in millions)* **2015**	2014	*(gigawatt hours)* **2015**	2014	*($ per MWh)*[2] **2015**	2014
Domestic						
Residential	**$ 1,276**	$ 1,203	**12,129**	12,084	**$ 105.20**	$ 99.55
Light industrial and commercial	**1,252**	1,186	**13,669**	13,736	**91.59**	86.34
Large industrial	**565**	547	**10,264**	10,601	**55.05**	51.60
Other energy sales	**368**	203	**6,694**	1,113	**54.97**	182.39
Total Domestic Revenue Before Regulatory Transfer	**3,461**	3,139	**42,756**	37,534	**80.95**	83.63
Rate smoothing and load variance regulatory transfer	**149**	310	-	-	-	-
Total Domestic	**$ 3,610**	$ 3,449	**42,756**	37,534	**$ 84.43**	$ 91.89
Trade						
Electricity - Gross	**$ 480**	$ 785	**10,257**	17,135	**$ 46.80**	$ 45.81
Less: forward electricity purchases	**(150)**	(185)	-	-	-	-
Electricity - Net	**330**	600	-	-	-	-
Gas - Gross	**347**	689	**11,719**	15,887	**29.61**	43.37
Less: forward gas purchases	**(214)**	(545)	-	-	-	-
Gas - Net	**133**	144	-	-	-	-
Total Trade[1]	**$ 463**	$ 744	**21,976**	33,022	**$ 21.07**	$ 22.53
Total	**$ 4,073**	$ 4,193	**64,732**	70,556	**$ 62.92**	$ 59.43

[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 December 31, 2015 were $1,352 million, an increase of $62 million or 5 per cent over the same period in the prior fiscal year. Domestic revenues before regulatory account transfers for the three months ended December 31, 2015 were $1,247 million, an increase of $89 million or 8 per cent over the same period in the prior fiscal year.

Total domestic revenues after regulatory account transfers for the nine months ended December 31, 2015 were $3,610 million, an increase of $161 million or 5 per cent over the same period in the prior fiscal year. Domestic revenues before regulatory account transfers for the nine months ended December 31, 2015 were $3,461 million, an increase of $322 million or 10 per cent over the same period in the prior fiscal year. The increase for the three and nine months ended December 31, 2015 compared to the same periods in the prior fiscal year was primarily due to higher average customer rates and higher other energy sales.

Average customer rates were higher in fiscal 2016 compared to the prior fiscal year, reflecting an average rate increase as approved by the BCUC of 6 per cent effective April 1, 2015.

Other energy sales were higher as a result of surplus energy sold (586 GWh for the three months ended December 31, 2015 and 5,603 GWh for the nine months ended December 31, 2015) into the market as compared to the same period in the prior fiscal year (nil for the three months ended December 31, 2014 and 14 GWh for the nine months ended December 31, 2014). Surplus energy sales were required to reduce spill risk, as a result of higher reservoir levels at the start of the fiscal year resulting from increased storage through the fall and winter of the prior year due to low market prices, and as well as increased generation at Mica in the current year to maintain downstream Arrow reservoir levels to support summer recreation and ferry service and to meet Columbia River Treaty obligations. Surplus sales vary year to year based on level and timing of inflows, risk of spill, and market conditions.

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 a key participant in energy markets across North America, buying and supplying wholesale power, natural gas, ancillary services, financial energy products, and environmental products with an expanding list of trade partners.

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 help the Company 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 can be met.

Total trade revenues for the three months ended December 31, 2015 were $151 million, a decrease of $40 million or 21 per cent compared with the same period in the prior fiscal year. The decrease in revenue was primarily due to a 26 per cent decrease in the average electricity sales price and a 15 per cent decrease in the volume of physical electricity sold. The decrease in the average electricity sales price was primarily due to overall lower market prices in Western North America primarily as a result of lower North American natural gas prices. The decrease in the volume of physical electricity sold for trade was primarily due to an outage for the Pacific DC transmission line, a key third party transmission line to California, and higher volumes of surplus energy sold for domestic purposes.

Total trade revenues for the nine months ended December 31, 2015 were $463 million, a decrease of $281 million or 38 per cent compared with the same period in the prior fiscal year. The decrease in revenue was primarily due to a 40 per cent decrease in the volume of physical electricity sold and a 32 per cent decrease in the average natural gas sales price as well as a 26 per cent decrease in the volume of physical gas sold. The decrease in the volume of physical electricity sold for trade was primarily due to higher volumes of surplus energy sold for domestic purposes as well as an outage for the Pacific DC transmission line mentioned above. The decrease in the average natural gas sales price was reflective of an increase in gas production in the U.S. and mild temperatures in Eastern North America in the current year, as well as overall higher natural gas prices in North America in the prior fiscal year due to depleted inventory in storage. The decrease in the volume of physical gas sold was primarily due to lower gas trading opportunities following decreased demand due to warmer temperatures.

Variances between actual and planned trade income (which includes trade revenues) are deferred to the Trade Income Deferral Account (TIDA).

OPERATING EXPENSES

For the three and nine months ended December 31, 2015, total operating expenses of $1,099 million and $3,161 million, respectively, were $13 million and $196 million lower than in the same period in the prior fiscal year. The decrease in both periods was primarily the result of lower expenditures for trade electricity and gas purchases and lower expenditure for domestic energy costs partially offset by higher materials and external services costs and higher amortization and depreciation expense.

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 December 31, 2015 were $497 million, $54 million or 10 per cent lower than the same period in the prior fiscal year. Total energy costs after regulatory transfers for the nine months ended December 31, 2015 were $1,386 million, $295 million or 18 per cent lower than the same period in the prior fiscal year. The decrease in both periods was primarily due to lower trade electricity and gas purchases partially offset by higher Independent Power Producers (IPPs) purchases.

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For the three months ended December 31	(in millions) 2015	2014	(gigawatt hours) 2015	2014	($ per MWh)[2] 2015	2014
Domestic						
Water rental payments (hydro generation)[1]	**$ 80**	$ 85	**12,212**	10,929	**$ 6.44**	$ 7.94
Purchases from Independent Power Producers	**340**	307	**3,719**	3,767	**91.38**	81.59
Other electricity purchases - Domestic	**1**	1	**25**	44	**33.52**	25.94
Gas for thermal generation	**7**	9	**62**	58	**119.88**	155.73
Transmission charges and other expenses	**10**	25	**31**	33	**-**	-
Allocation (to) from trade energy	**-**	14	**(26)**	384	**22.90**	38.13
Total Domestic Cost of Energy Before Regulatory Transfers	**438**	441	**16,023**	15,215	**27.31**	28.99
Domestic cost of energy regulatory transfers	**(63)**	(43)	**-**	-	**-**	-
Total Domestic	**$ 375**	$ 398	**16,023**	15,215	**$ 23.39**	$ 26.13
Trade						
Electricity - Gross	**$ 84**	$ 144	**3,389**	4,398	**$ 24.79**	$ 32.74
Less: forward electricity purchases	**(33)**	(40)	**-**	-	**-**	-
Electricity - Net	**51**	104	**-**	-	**-**	-
Remarketed gas - Gross	**97**	199	**4,371**	5,152	**22.19**	38.63
Less: forward gas purchases	**(68)**	(179)	**-**	-	**-**	-
Remarketed gas - Net	**29**	20	**-**	-	**-**	-
Transmission charges and other expenses	**53**	56	**-**	-	**-**	-
Allocation from (to) domestic energy	**-**	(14)	**26**	(384)	**22.90**	38.13
Total Trade Cost of Energy Before Regulatory Transfers	**133**	166	**7,786**	9,166	**21.41**	22.54
Trade net margin regulatory transfer	**(11)**	(13)	**-**	-	**-**	-
Total Trade[3]	**$ 122**	$ 153	**7,786**	9,166	**$ 20.04**	$ 21.09
Total Energy Costs	**$ 497**	$ 551	**23,809**	24,381	**$ 22.29**	$ 24.25

For the nine months ended December 31	(in millions) 2015	2014	(gigawatt hours) 2015	2014	($ per MWh)[2] 2015	2014
Domestic						
Water rental payments (hydro generation)[1]	**$ 235**	$ 253	**35,651**	29,490	**$ 6.43**	$ 8.68
Purchases from Independent Power Producers	**939**	786	**11,359**	10,318	**82.65**	76.21
Other electricity purchases - Domestic	**1**	3	**32**	93	**26.22**	33.75
Gas for thermal generation	**21**	26	**153**	161	**140.10**	161.70
Transmission charges and other expenses	**20**	8	**77**	82	**-**	-
Allocation (to) from trade energy	**(6)**	27	**(262)**	728	**26.80**	35.06
Total Domestic Cost of Energy Before Regulatory Transfers	**1,210**	1,103	**47,010**	40,872	**25.73**	26.99
Domestic cost of energy regulatory transfers	**(161)**	(17)	**-**	-	**-**	-
Total Domestic	**$ 1,049**	$ 1,086	**47,010**	40,872	**$ 22.30**	$ 26.57
Trade						
Electricity - Gross	**$ 268**	$ 513	**9,872**	17,823	**$ 27.15**	$ 28.78
Less: forward electricity purchases	**(150)**	(185)	**-**	-	**-**	-
Electricity - Net	**118**	328	**-**	-	**-**	-
Remarketed gas - Gross	**288**	664	**11,912**	16,094	**24.18**	41.26
Less: forward gas purchases	**(214)**	(545)	**-**	-	**-**	-
Remarketed gas - Net	**74**	119	**-**	-	**-**	-
Transmission charges and other expenses	**153**	184	**-**	-	**-**	-
Allocation from (to) domestic energy	**6**	(27)	**262**	(728)	**26.80**	35.06
Total Trade Cost of Energy Before Regulatory Transfers	**351**	604	**22,046**	33,189	**22.74**	23.78
Trade net margin regulatory transfer	**(14)**	(9)	**-**	-	**-**	-
Total Trade[3]	**$ 337**	$ 595	**22,046**	33,189	**$ 22.11**	$ 23.50
Total Energy Costs	**$ 1,386**	$ 1,681	**69,056**	74,061	**$ 22.24**	$ 25.20

1. Total GWh is net of storage exchange.

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

3. 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.

Domestic Energy Costs

Total domestic energy costs after regulatory transfers for the three months ended December 31, 2015 were $375 million, $23 million or 6 per cent lower than in the same period in the prior fiscal year. Domestic energy costs before regulatory transfers for the three months ended December 31, 2015 were $438 million, $3 million or 1 per cent lower than in the same period in the prior fiscal year.

Total domestic energy costs after regulatory transfers for the nine months ended December 31, 2015 were $1,049 million, $37 million or 3 per cent lower than the same period in the prior fiscal year. Domestic energy costs before regulatory transfers of $1,210 million for the nine months ended December 31, 2015 were $107 million or 10 per cent higher than the same period in the prior fiscal year. The increase in costs, before regulatory transfers, for the nine month period was primarily due to a higher volume of purchases from IPPs due to an increased number of IPPs in operation in the current period compared to the prior period. This was partially offset by lower water rental payments, which are based on the prior year’s generation volumes. In the prior year, hydro generation was low due to low water inflows and system constraints.

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 account transfers for the three months ended December 31, 2015 were $122 million, a decrease of $31 million or 20 per cent compared to the same period in the prior fiscal year. Total trade energy costs before regulatory account transfers for the three months ended December 31, 2015 were $133 million, a decrease of $33 million or 20 per cent compared with the same period in the prior fiscal year. The decrease was primarily due to a 24 per cent decrease in the average electricity price as well as a 23 per cent decrease in the volume of physical electricity purchased. The decrease in the average electricity purchase price and volume of physical electricity purchased was consistent with the decrease in the average electricity sales price and physical electricity volumes sold, respectively.

Total trade energy costs after regulatory account transfers for the nine months ended December 31, 2015 were $337 million, a decrease of $258 million or 43 per cent compared to the same period in the prior fiscal year. Total trade energy costs before regulatory account transfers for the nine months ended December 31, 2015 were $351 million, a decrease of $253 million or 42 per cent compared with the same period in the prior fiscal year. The decrease was primarily due to a 45 per cent decrease in the volume of physical electricity purchased and a 41 per cent decrease in the average gas purchase price as well as a 26 per cent decrease in the physical volume of gas purchased. The decrease in volume of physical electricity and physical gas purchased was consistent with the decrease in physical electricity and physical gas sold, respectively. The decrease in the average gas purchase price was primarily reflective of an increase in production in the U.S. and mild temperatures in Eastern North America in the current year, as well as overall higher natural gas prices in North America in the prior fiscal year due to depleted inventory in storage.

Variances between actual and planned trade income (which includes trade energy costs) are deferred to the TIDA.

Water Inflows

Water inflows for the three months ended December 31, 2015 were 111 per cent of average, with Williston and Kinbasket reservoir inflows at 131 and 117 per cent of average, respectively, compared to 118 per cent of average in the same period in the prior fiscal year (Williston 125 per cent and Kinbasket 146 per cent). Water inflows for the nine months ended December 31, 2015 were 97 per cent of average, with Williston and Kinbasket reservoir inflows at 100 and 108 per cent of average, respectively, compared to 98 per cent of average in the same period in the prior fiscal year (Williston 89 per cent and Kinbasket 108 per cent). The system inflow for fiscal 2016 is forecast to be 97 per cent of average, compared to the system inflow for fiscal 2015 which was 102 per cent of average.

Approximately 16 per cent of the system inflow for the fiscal year occurs in the third quarter and is due to a mix of rainfall and base flow in interior basins and rainfall in coastal basins. Warmer than average temperatures in October resulted in above average inflows due to the precipitation, which was actually below average, appearing as rainfall instead of snow.

The Williston and Kinbasket reservoirs have been managed such that system energy storage on December 31, 2015 was 21,900 GWh, or 1,400 GWh above the 10 year historic average. This was 800 GWh lower than the system energy storage of 22,700 GWh recorded one year earlier. Williston and Kinbasket reservoir energy contents were 15,400 GWh (1,800 GWh above the 10 year historic average) and 6,500 GWh (400 GWh below the 10 year historic average), respectively, with Williston 1,800 GWh higher than the prior fiscal year and Kinbasket 2,600 GWh lower than the prior fiscal year. The relative imbalance between the Williston and Kinbasket reservoir operations during this period was due to running Mica to support Arrow reservoir levels while meeting Arrow releases obligated under the Columbia River Treaty. This imbalance is expected to narrow in the upcoming fiscal year.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the three and nine months ended December 31, 2015 were $130 million and $393 million, respectively, $10 million and $9 million higher, respectively than the same period in the prior fiscal year.

Materials and External Services

Expenditures on materials and external services for the three and nine months ended December 31, 2015 were $153 million and $448 million, respectively, $18 million and $38 million higher, respectively than the same period in the prior fiscal year, primarily due to increased expenditures on energy purchase agreements (EPAs) accounted for as finance leases and a recovery from a third party recognized in the prior year.

Amortization and Depreciation Expense

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 and nine months ended December 31, 2015, amortization and depreciation expense was $317 million and $923 million, respectively, $16 million and $38 million higher, respectively than the same period in the prior fiscal year, primarily due to an increase in depreciation of property, plant and equipment due to more assets in service.

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 and nine months ended December 31, 2015 were $56 million and $166 million, respectively, comparable to total grants and taxes of $62 million and $165 million, respectively in the same period in the prior fiscal year.

Capitalized Costs

Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from operating costs to PP&E. Certain overhead costs not eligible for capitalization under IFRS are transferred from operating costs to the IFRS PP&E regulatory account. These transfers are amortized over 40 years which approximates the composite average life of the PP&E. 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 PP&E 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 and nine months ended December 31, 2015 were $54 million and $155 million, respectively, $3 million and $13 million lower, respectively than in the same period in the prior fiscal year. The reduction in capitalized costs was primarily due to the annual reduction of the transfer of operating costs to the IFRS PP&E account as discussed above.

FINANCE CHARGES

Finance charges for the three months ended December 31, 2015 were $187 million, $21 million or 13 per cent higher than the same period in the prior fiscal year. The increase was primarily due to higher planned volume of long term debt borrowings and higher planned short term interest rates. Finance charges for the nine months ended December 31, 2015 were $562 million, $94 million or 20 per cent higher than in the same period in the prior fiscal year. The increase was primarily due to higher planned volume of long term debt borrowings, higher planned lease charges, and higher planned short term interest rates.

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:

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2015**	2014	**2015**	2014
Energy Accounts				
Heritage Deferral Account	**$ 5**	$ 46	**$ (112)**	$ 85
Non-Heritage Deferral Account	**127**	86	**319**	124
Trade Income Deferral Account	**11**	14	**18**	11
	143	146	**225**	220
Forecast Variance Accounts				
Finance Charges	**(40)**	(37)	**(129)**	(80)
Rate Smoothing Account	**32**	44	**86**	118
Other	**13**	4	**25**	(10)
	5	11	**(18)**	28
Capital-Like Accounts				
Demand-Side Management (DSM)	**45**	35	**96**	74
Site C	**-**	19	**-**	65
Smart Metering and Infrastructure (SMI)	**4**	5	**10**	11
IFRS Property, Plant and Equipment	**34**	40	**101**	118
	83	99	**207**	268
Non-Cash Accounts				
Environmental Provisions & Costs	**-**	11	**(4)**	20
First Nations Costs & First Nations Provisions	**8**	2	**13**	9
Other	**2**	2	**4**	5
	10	15	**13**	34
Amortization of regulatory accounts	**(128)**	(123)	**(350)**	(356)
Interest on regulatory accounts	**18**	17	**54**	50
Net change in regulatory accounts	**$ 131**	$ 165	**$ 131**	$ 244

For the three and nine months ended December 31, 2015, net additions to the Company's regulatory accounts after amortization and interest were $131 million and $131 million, respectively, $34 million and $113 million lower, respectively, than the same periods in the prior fiscal year. The net asset balance in the regulatory asset and liability accounts as at December 31, 2015 was an asset of $5,564 million compared to an asset of $5,433 million as at March 31, 2015.
Net additions to the regulatory accounts during the nine months ended December 31, 2015 included:

- Increases of $225 million to the energy deferral accounts primarily due to higher IPP costs and lower domestic revenues, partially offset by higher surplus sales;

- Transfers of $101 million to the IFRS PP&E 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;
- Planned expenditures of $96 million on DSM projects, which support energy conservation;
- Increases of $86 million to the Rate Smoothing regulatory account for smoothing the rate impacts of the rate increases in the 10 year rate plan; and;
- Interest on regulatory accounts of $54 million.

These net additions were partially offset by:

- Net amortization of $350 million which is the regulatory mechanism to recover the regulatory account balances in rates; and
- Transfers of $129 million to the Finance Charges regulatory liability account primarily due to $55 million for an EPA accounted for as an operating lease but planned as a finance lease, $42 million relating to interest rate variance, $21 million relating to Interest During Construction (IDC) variance, and $18 million volume variance for net borrowings.

BC Hydro has regulatory mechanisms in place to collect 25 of 27 regulatory accounts, which represent approximately 88 per cent of the total net regulatory account balance, in rates over various periods.

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. The Payment accrued as at December 31, 2015 is $32 million (March 31, 2015 - $264 million), which is included in accounts payable and accrued liabilities and is less than 85 per cent of the Company's net income due to the 80:20 cap.

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).

Upcoming Revenue Requirements Application

BC Hydro is undertaking preparations for the filing in February 2016 of its next revenue requirements application for the test period of fiscal 2017 to fiscal 2019.

Rate Design Application (RDA)

On September 24, 2015, BC Hydro filed Module 1 of its 2015 RDA with the BCUC. Among the various approvals sought in Module 1 of the 2015 RDA, 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 first round of Commission and Intervener information requests responses was filed in December 2015. A procedural conference was held in January 2016, and BC Hydro anticipates receiving a second round of information requests in February 2016. A final decision is expected late in calendar 2016. Rate design changes are designed to be revenue neutral to the utility.

WAC Bennett Rip Rap Filing

On November 13, 2015, BC Hydro filed an application with the BCUC requesting an order accepting the capital expenditures for the W.A.C. Bennett Rip Rap Upgrade Project. The project seeks to replace the rock armour layer (known as rip rap) that protects against erosion of the underlying fill layers of the dam. Commission and Intervener information requests were received in December 2015, and was responded to in January 2016. A procedural conference was held on January 27, 2016.

Debt Management Regulatory Account

On December 16, 2015, BC Hydro filed an application with the BCUC requesting an order approving the establishment of a new regulatory account (the Debt Management Regulatory Account) to capture mark-to-market gains and losses of financial contracts that the Company wishes to enter into to hedge long-term future debt. This new account, if approved, will assist BC Hydro in mitigating risks of higher interest rates while borrowing to support its capital plan. The BCUC held a workshop on the proposed Regulatory Account on January 27, 2016, with a round of Commission and Intervener information requests to follow and an expected decision in March 2016.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the nine months ended December 31, 2015 was $634 million compared with cash flow provided by operating activities of $558 million in the same period in the prior fiscal year. The increase was mainly due to higher income from operating activities partially offset by changes in working capital.

The long-term debt balance net of sinking funds at December 31, 2015 was $18,013 million, compared with $16,721 million at March 31, 2015, a net increase of $1,292 million. The increase was primarily a result of an increase in long-term debt bond issues totaling $1,864 million ($1,891 million par value) and net foreign exchange losses of $108 million. These increases were partially offset by a decrease in revolving borrowings of $515 million, and long-term bond redemptions totaling $150 million par value. Long-term debt increased primarily to fund capital cash expenditures.

CAPITAL EXPENDITURES

Capital expenditures, which include property, plant and equipment and intangible assets, were as follows:

(in millions)	*For the three months ended December 31* **2015**	2014	*For the nine months ended December 31* **2015**	2014
Transmission lines and substations replacements & expansion	**$ 133**	$ 358	**$ 493**	$ 808
Generation replacements and expansion	**127**	130	**373**	373
Distribution system improvements and expansion	**124**	82	**343**	272
General, including technology, vehicles and buildings	**42**	59	**120**	136
Site C Clean Energy project	**168**	-	**238**	-
Total Capital Expenditures	**$ 594**	$ 629	**$ 1,567**	$ 1,589

Total capital expenditures presented in this table are different from the expenditures in the Consolidated Interim Statements of Cash Flows due to the effect of accruals related to these expenditures.

Transmission lines and substation capital expenditures includes expenditures on the Interior to Lower Mainland Transmission Line, Dawson Creek/Chetwynd Area Transmission, Surrey Area Substation, Horsey to George Tripp Substation 230kV Cable, Big Bend Substation, Arnott Capacity Upgrade, Merritt Area Transmission, Good Hope Lake and Long Beach Area Transmission projects and the Transmission Wood Structure Replacement program.

Generation capital expenditures include expenditures for John Hart Generating Station Replacement, Ruskin Dam Safety and Powerhouse Upgrade, Upper Columbia Capacity Additions at Mica – Unit 5 and Unit 6, Hugh Keenleyside Spillway Gate Reliability and G.M. Shrum Units 1-5 Turbine Rehabilitation projects.

Distribution capital expenditures include expenditures on customer driven work, end of life asset replacements, system expansion and improvements, and the Smart Metering and Infrastructure project.

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

Site C Clean Energy project expenditures incurred after the provincial government’s positive investment decision in December 2014 are recorded as capital and include expenditures in support of construction which started in July 2015.

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 has a documented plan for the recovery of its regulatory accounts which it filed with the F2015-F2016 Revenue Requirements Rate Application.

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 EPAs. 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 Report for the year ended March 31, 2015. In addition, information on risks and opportunities that could significantly impact BC Hydro meeting its objectives are outlined at **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 2015 forecasted net income for fiscal 2016 at $653 million.

BC Hydro filed an updated forecast with the Province in January 2016 which is incorporated into the February 2016 Service Plan and forecasts a net income of $653 million for fiscal 2016 and $692 million for fiscal 2017.

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 forecast for fiscal 2017 assumes average water inflows (100 per cent of average), domestic sales load of 56,692 GWh, average market energy prices of US $24.15/MWh, short-term interest rates of 0.68 per cent, and a U.S. dollar exchange rate of US$0.7646.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	*For the three months ended December 31* **2015**	2014	*For the nine months ended December 31* **2015**	2014
Revenues				
Domestic	**$ 1,352**	$ 1,290	**$ 3,610**	$ 3,449
Trade	**151**	191	**463**	744
	1,503	1,481	**4,073**	4,193
Expenses				
Operating expenses (Note 4)	**1,099**	1,112	**3,161**	3,357
Finance charges (Note 5)	**187**	166	**562**	468
Net Income	**217**	203	**350**	368
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 15)	**18**	22	**54**	31
Reclassification to income on derivatives designated as cash flow hedges (Note 15)	**(40)**	(31)	**(96)**	(43)
Foreign currency translation gains	**8**	8	**24**	12
Other Comprehensive Loss	**(14)**	(1)	**(18)**	-
Total Comprehensive Income	**$ 203**	$ 202	**$ 332**	$ 368

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(in millions)	***As at December 31 2015***	*As at March 31* 2015
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 131**	$ 39
Accounts receivable and accrued revenue	**706**	627
Inventories (Note 7)	**186**	122
Prepaid expenses	**100**	211
Current portion of derivative financial instrument assets (Note 15)	**168**	152
	1,291	1,151
Non-Current Assets		
Property, plant and equipment (Note 8)	**20,938**	19,933
Intangible assets (Note 8)	**516**	547
Regulatory assets (Note 9)	**5,937**	5,714
Derivative financial instrument assets (Note 15)	**157**	97
Other non-current assets (Note 10)	**325**	311
	27,873	26,602
	$ 29,164	$ 27,753
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 1,283**	$ 1,708
Current portion of long-term debt (Note 11)	**3,031**	3,698
Current portion of derivative financial instrument liabilities (Note 15)	**93**	85
	4,407	5,491
Non-Current Liabilities		
Long-term debt (Note 11)	**15,157**	13,178
Regulatory liabilities (Note 9)	**373**	281
Derivative financial instrument liabilities (Note 15)	**32**	38
Contributions in aid of construction	**1,650**	1,583
Post-employment benefits (Note 13)	**1,522**	1,498
Other non-current liabilities (Note 14)	**1,553**	1,514
	20,287	18,092
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**4,386**	4,068
Accumulated other comprehensive income	**24**	42
	4,470	4,170
	$ 29,164	$ 27,753

Commitments (Note 8)

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

Approved on behalf of the Board:

Brad Bennett
Chair, Board of Directors

James Brown
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, April 1, 2014	$ 33	$ 21	$ 54	$ 60	$ 3,751	$ 3,865
Payment to the Province (Note 12)	-	-	-	-	(86)	(86)
Comprehensive Income (Loss)	12	(12)	-	-	368	368
Balance, December 31, 2014	$ 45	$ 9	$ 54	$ 60	$ 4,033	$ 4,147
Balance, April 1, 2015	$ 67	$ (25)	$ 42	$ 60	$ 4,068	$ 4,170
Payment to the Province (Note 12)	-	-	-	-	(32)	(32)
Comprehensive Income (Loss)	24	(42)	(18)	-	350	332
Balance, December 31, 2015	$ 91	$ (67)	$ 24	$ 60	$ 4,386	$ 4,470

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(in millions)	*For the nine months ended December 31* **2015**	2014
Operating Activities		
Net income	**$ 350**	$ 368
Regulatory account transfers (Note 9)	**(481)**	(600)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 9)	**350**	356
Amortization and depreciation expense (Note 6)	**557**	508
Unrealized gains on mark-to-market	**(26)**	(36)
Employee benefit plan expenses	**83**	63
Interest accrual	**534**	500
Other items	**63**	46
	1,430	1,205
Changes in:		
Restricted cash	**-**	322
Accounts receivable and accrued revenue	**(57)**	99
Prepaid expenses	**112**	96
Inventories	**(58)**	(57)
Accounts payable, accrued liabilities and other non-current liabilities	**(241)**	(629)
Contributions in aid of construction	**75**	105
	(169)	(64)
Interest paid	**(627)**	(583)
Cash provided by operating activities	**634**	558
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(1,472)**	(1,473)
Cash used in investing activities	**(1,472)**	(1,473)
Financing Activities		
Long-term debt:		
Issued (Note 11)	**1,864**	1,256
Retired	**(150)**	(325)
Receipt of revolving borrowings	**6,198**	6,431
Repayment of revolving borrowings	**(6,709)**	(6,321)
Payment to the Province (Note 12)	**(264)**	(167)
Other items	**(9)**	(13)
Cash provided by financing activities	**930**	861
Increase (decrease) in cash and cash equivalents	**92**	(54)
Cash and cash equivalents, beginning of period	**39**	107
Cash and cash equivalents, end of period	**$ 131**	$ 53

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 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 upon consolidation.

The Company accounts for its one third interest in Waneta as a joint operation. The consolidated 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 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 its consolidated 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 periods 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 9.

These condensed consolidated interim statements have been prepared by management in accordance with the 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 2015 Annual Report except as described in Note 3. These interim condensed consolidated financial statements should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2015 Annual Report. Certain amounts in the comparative figures in the statement of financial position have been reclassified to conform to the presentation adopted in the current year.

These condensed consolidated interim financial statements were approved on behalf of the Board of Directors on February 1, 2016.

NOTE 3: CHANGES IN ACCOUNTING POLICIES

Effective April 1, 2015, the Company adopted Amendments to IAS 19, *Employee Benefits* which had no impact on the consolidated financial statements.

NOTE 4: OPERATING EXPENSES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2015**	2014	**2015**	2014
Electricity and gas purchases	**$ 370**	$ 427	**$ 1,005**	$ 1,310
Water rentals	**91**	89	**274**	267
Transmission charges	**36**	35	**107**	104
Personnel expenses	**130**	120	**393**	384
Materials and external services	**153**	135	**448**	410
Amortization and depreciation (Note 6)	**317**	301	**923**	885
Grants, taxes and other costs	**56**	62	**166**	165
Capitalized costs	**(54)**	(57)	**(155)**	(168)
	$ 1,099	$ 1,112	**$ 3,161**	$ 3,357

NOTE 5: FINANCE CHARGES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2015**	2014	**2015**	2014
Interest on long-term debt	**$ 192**	$ 175	**$ 578**	$ 512
Interest on finance lease liabilities	**24**	25	**71**	54
Net interest expense on net defined benefit liability	-	-	-	2
Less: capitalized interest	**(15)**	(17)	**(46)**	(51)
Total finance costs	**201**	183	**603**	517
Other recoveries	**(14)**	(17)	**(41)**	(49)
	$ 187	$ 166	**$ 562**	$ 468

NOTE 6: AMORTIZATION AND DEPRECIATION

(in millions)	*For the three months ended December 31* **2015**	2014	*For the nine months ended December 31* **2015**	2014
Depreciation of property, plant and equipment	**$ 171**	$ 154	**$ 507**	$ 461
Amortization of intangible assets	**17**	16	**50**	47
Amortization of regulatory accounts	**129**	131	**366**	377
	$ 317	$ 301	**$ 923**	$ 885

NOTE 7: INVENTORIES

(in millions)	***As at December 31*** **2015**	*As at March 31* 2015
Materials and supplies	**$ 125**	$ 110
Natural gas trading inventories	**61**	12
	$ 186	$ 122

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

NOTE 8: PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Property, plant and equipment and intangible asset expenditures for the three and nine months ended December 31, 2015 were $594 million and $1,567 million, respectively (2014 – $629 million and $1,589 million, respectively).

As of December 31, 2015, the Company has contractual commitments to spend $3,580 million on major property, plant and equipment projects (for individual projects greater than $50 million).

NOTE 9: RATE REGULATION

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 comprehensive income unless the Company sought recovery through rates in the period which they are incurred. For the three and nine months ended December 31, 2015, the impact of regulatory accounting has resulted in a net increase of $131 million and $131 million, respectively, to comprehensive income (three and nine months ended December 31, 2014 - $165 million increase and $244 million increase, respectively). For each regulatory account, the amount reflected in the Net Change column in the following regulatory table represents the impact on comprehensive income for the applicable period, unless otherwise recovered through rates. Under rate regulated accounting, a net increase in a regulatory asset results in an increase, and a net increase in a regulatory liability results in a decrease, to comprehensive income, respectively.

(in millions)	*April 1 2015*	*Addition (Reduction)*	*Interest*	*Amortization*	*Net Change*	*December 31 2015*
Regulatory Assets						
Heritage Deferral Account	$ 165	$ (112)	$ 1	$ (27)	$ (138)	$ 27
Non-Heritage Deferral Account	524	319	18	(85)	252	776
Trade Income Deferral Account	244	18	7	(39)	(14)	230
Demand-Side Management Programs	842	96	-	(60)	36	878
First Nations Costs & First Nations Provisions	564	13	5	(32)	(14)	550
Non-Current Pension Cost	564	13	-	(12)	1	565
Site C	419	-	12	-	12	431
CIA Amortization	87	4	-	-	4	91
Environmental Provisions & Costs	382	(4)	1	(55)	(58)	324
Smart Metering and Infrastructure (SMI)	283	10	9	(23)	(4)	279
IFRS Pension & Other Post-Employment Benefits	650	-	-	(29)	(29)	621
IFRS Property, Plant and Equipment	758	101	-	(15)	86	844
Rate Smoothing Account	166	86	-	-	86	252
Other Regulatory Accounts	66	17	1	(15)	3	69
Total Regulatory Assets	5,714	561	54	(392)	223	5,937
Regulatory Liabilities						
Future Removal and Site Restoration Costs	33	-	-	(16)	(16)	17
Foreign Exchange Gains and Losses	71	(12)	-	-	(12)	59
Finance Charges	173	129	-	(19)	110	283
Other Regulatory Accounts	4	17	-	(7)	10	14
Total Regulatory Liabilities	281	134	-	(42)	92	373
Net Regulatory Asset	$ 5,433	$ 427	$ 54	$ (350)	$ 131	$ 5,564

In September 2015, the BCUC approved BC Hydro’s application to defer in the Non-Current Pension Cost regulatory account the operating cost variance between the forecast (as per the F2015-F2016 Revenue Requirements Rate Application) and the actual fiscal 2016 post-employment benefits current pension costs arising from a change in the actuarial discount rate. The expected variance (and therefore the expected deferral) for fiscal 2016 is $17 million, of which $13 million was deferred as at December 31, 2015.

NOTE 10: OTHER NON-CURRENT ASSETS

(in millions)	***As at December 31 2015***	*As at March 31* 2015
Sinking funds	**$ 175**	$ 155
Non-current receivable	**150**	156
	$ 325	$ 311

NOTE 11: 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 $4.5 billion, and is included in revolving borrowings. At December 31, 2015, the outstanding amount under the borrowing program was $3,031 million (2014 – $3,873 million).

In the three month period ended December 31, 2015, the Company issued bonds with net proceeds of $695 million and par value of $691 million (2014 - $nil), a weighted average effective interest rate of 2.5 per cent and a weighted average term to maturity of 9.8 years. For the nine month period ended December 31, 2015, the Company issued bonds with net proceeds of $1,864 million and par value of $1,891 million (2014 – net proceeds of $1,256 million and par value of $1,365 million), a weighted average effective interest rate of 2.7 per cent (2014 – 3.6 per cent) and a weighted average term to maturity of 20.9 years (2014 – 29.9 years).

NOTE 12: 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. 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 nine months ended December 31, 2015, there were no changes in the approach to capital management.

The debt to equity ratio at December 31, 2015, and March 31, 2015 was as follows:

(in millions)	***As at December 31*** **2015**	*As at March 31* 2015
Total debt, net of sinking funds	**$ 18,013**	$ 16,721
Less: Cash and cash equivalents	**(131)**	(39)
Net Debt	**$ 17,882**	$ 16,682
Retained earnings	**$ 4,386**	$ 4,068
Contributed surplus	**60**	60
Accumulated other comprehensive income	**24**	42
Total Equity	**$ 4,470**	$ 4,170
Net Debt to Equity Ratio	**80 : 20**	80 : 20

Payment to 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 Province, 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. The Payment accrued as at December 31, 2015 is $32 million (March 31, 2015 - $264 million), which is included in accounts payable and accrued liabilities and is less than 85 per cent of the net income due to the 80:20 cap.

NOTE 13: POST-EMPLOYMENT BENEFITS

The expense recognized in the statement 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 and nine months ended December 31, 2015 was $43 million and $128 million, respectively (2014 - $36 million and $108 million, respectively).

Company contributions to the registered defined benefit pension plans for the three and nine months ended December 31, 2015 were $16 million and $48 million, respectively (2014 - $16 million and $48 million, respectively).

NOTE 14: OTHER NON-CURRENT LIABILITIES

(in millions)	***As at December 31* 2015**	*As at March 31* 2015
Provisions		
Environmental liabilities	**$ 347**	$ 368
Decommissioning obligations	**50**	53
Other	**10**	27
	407	448
First Nations liabilities	**409**	414
Finance lease obligations	**245**	259
Other liabilities	**130**	81
Deferred revenue - Skagit River Agreement	**466**	441
	1,657	1,643
Less: Current portion, included in accounts payable and accrued liabilities	**(104)**	(129)
	$ 1,553	$ 1,514

NOTE 15: 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 and nine months ended December 31, 2015 and 2014.

Categories of Financial Instruments

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at December 31, 2015 and March 31, 2015. The non-derivative financial instruments, where carrying value differs from fair value, would be classified as Level 2 of the fair value hierarchy.

(in millions)	**December 31, 2015** Carrying Value	**December 31, 2015** Fair Value	March 31, 2015 Carrying Value	March 31, 2015 Fair Value
Financial Assets and Liabilities at Fair Value Through Profit or Loss:				
Cash equivalents - short-term investments	**$ 40**	**$ 40**	$ 11	$ 11
Loans and Receivables:				
Accounts receivable and accrued revenue	**706**	**706**	627	627
Non-current receivable	**150**	**145**	156	162
Cash	**91**	**91**	28	28
Held to Maturity:				
Sinking funds – US	**175**	**196**	155	184
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**(1,283)**	**(1,283)**	(1,708)	(1,708)
Revolving borrowings - CAD	**(1,872)**	**(1,872)**	(2,623)	(2,623)
Revolving borrowings - US	**(1,159)**	**(1,159)**	(924)	(924)
Long-term debt (including current portion due in one year)	**(15,157)**	**(17,863)**	(13,329)	(16,799)
First Nations liabilities (non-current portion)	**(374)**	**(556)**	(391)	(758)
Finance lease obligations (non-current portion)	**(225)**	**(225)**	(240)	(240)
Other liabilities	**(130)**	**(135)**	(81)	(86)

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)	**December 31 2015 Fair Value**	March 31 2015 Fair Value
Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ 98**	$ 45
Foreign currency contracts (cash flow hedges for $EURO denominated long-term debt)	**(4)**	-
	94	45
Non-Designated Derivative Instruments:		
Foreign currency contracts	**53**	31
Commodity derivatives	**53**	50
	106	81
Net asset	**$ 200**	$ 126

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)	**December 31 2015**	March 31 2015
Current portion of derivative financial instrument assets	**$ 168**	$ 152
Current portion of derivative financial instrument liabilities	**(93)**	(85)
Derivative financial instrument assets, non-current	**157**	97
Derivative financial instrument liabilities, non-current	**(32)**	(38)
Net asset	**$ 200**	$ 126

For designated cash flow hedges for the three and nine months ended December 31, 2015, gains of $18 million and $54 million, respectively, (2014 - $22 million gain and $31 million gain, respectively) were recognized in other comprehensive income. For the three and nine months ended December 31, 2015, $40 million and $96 million, respectively (2014 - $31 million and $43 million, respectively) were removed from other comprehensive income and reported in net income, offsetting foreign exchange losses (2014 – losses) recorded in the respective periods.

For derivative instruments not designated as hedges, gains of $2 million and $7 million, respectively (2014 - $3 million gain and $3 million gain, respectively) were recognized in finance charges for the three and nine months ended December 31, 2015 with respect to foreign currency contracts for cash management purposes. For the three and nine months ended December 31, 2015, gains of $30 million and $100 million, respectively, (2014 - $1 million loss and $6 million loss, respectively) were recognized in finance charges with respect to foreign currency contracts for U.S. short-term borrowings. These economic hedges offset $103 million of foreign exchange revaluation losses (2014 - $5 million gain) recorded with respect to U.S. short-term borrowings for the nine months ended December 31, 2015. A net gain of $3 million and a net gain of $5 million, respectively (2014 - $24 million gain and $49 million gain, respectively) were recorded in trade revenue for the three and nine months ended December 31, 2015 with respect to commodity derivatives.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2015**	2014	**2015**	2014
Deferred inception loss, beginning of the period	**$ 64**	$ 46	**$ 70**	$ 50
New transactions	**(9)**	29	**(7)**	23
Amortization	**5**	-	**(3)**	2
Deferred inception loss, end of the period	**$ 60**	$ 75	**$ 60**	$ 75

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 table presents the financial assets and financial liabilities measured at fair value for each hierarchy level as at December 31, 2015 and March 31, 2015:

As at December 31, 2015 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 40	$ -	$ -	$ 40
Derivatives designated as hedges	-	98	-	98
Derivatives not designated as hedges	87	87	53	227
Total financial assets carried at fair value	$ 127	$ 185	$ 53	$ 365
Derivatives designated as hedges	$ -	$ (4)	$ -	$ (4)
Derivatives not designated as hedges	(103)	(12)	(6)	(121)
Total financial liabilities carried at fair value	$ (103)	$ (16)	$ (6)	$ (125)

As at March 31, 2015 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 11	$ -	$ -	$ 11
Derivatives designated as hedges	-	53	-	53
Derivatives not designated as hedges	72	77	47	196
Total financial assets carried at fair value	$ 83	$ 130	$ 47	$ 260
Derivatives designated as hedges	$ -	$ (8)	$ -	$ (8)
Derivatives not designated as hedges	(76)	(31)	(8)	(115)
Total financial liabilities carried at fair value	$ (76)	$ (39)	$ (8)	$ (123)

The Company determines Level 2 fair values for debt securities and derivatives using discounted cash flow techniques, which uses 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.

For the nine months ended December 31, 2015, energy derivatives with a carrying amount of $14 million were transferred from Level 2 to Level 1 as the Company now uses published price quotations in an active market. There were no transfers in the three months ended December 31, 2015.

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.

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 nine months ended December 31, 2015 and 2014:

(in millions)		
Balance at April 1, 2015	**$**	**39**
Cumulative impact of net loss recognized		(5)
New transactions		6
Existing transactions settled		7
Balance at December 31, 2015	**$**	**47**

(in millions)		
Balance at April 1, 2014	**$**	**43**
Cumulative impact of net loss recognized		(9)
New transactions		3
Existing transactions settled		(30)
Balance at December 31, 2014	**$**	**7**

Level 3 fair values for energy derivatives are determined using inputs that are not observable. 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.

Net losses of $9 million and $2 million, respectively, (2014 – net losses $23 million and $9 million, respectively) recognized in net income during the three and nine months ended December 31, 2015 relates to Level 3 financial instruments held at December 31, 2015. The net loss is recognized in trade revenue.

Methodologies and procedures regarding Powerex’s energy trading Level 3 fair value measurements are determined by Powerex’s Risk Management group. Level 3 Powerex fair values are calculated within Powerex’s Risk Management Policy 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 16: 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.