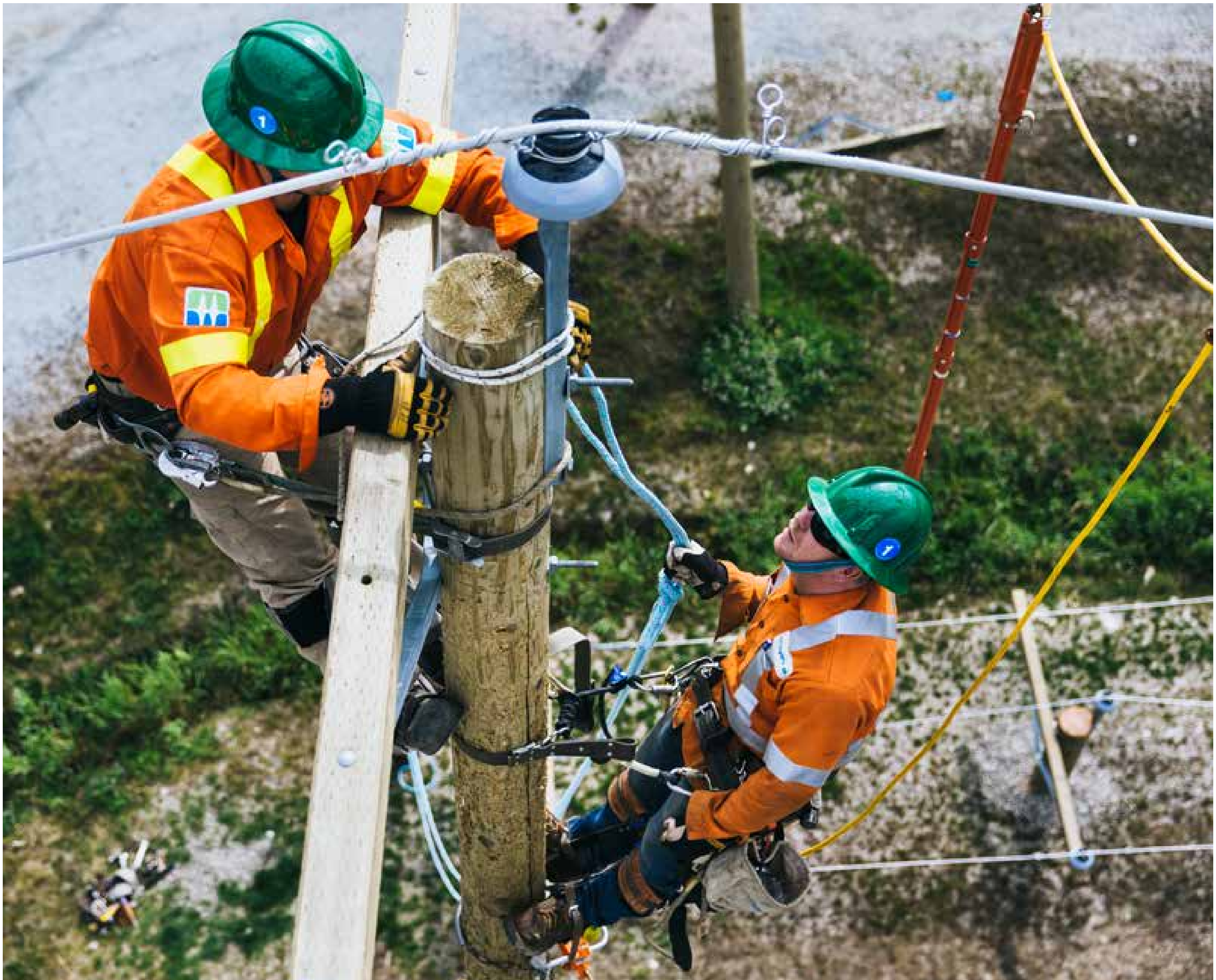

BC HYDRO THIRD QUARTER REPORT FISCAL 2015

BC hydro
FOR GENERATIONS

BRITISH COLUMBIA

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, 2014 and should be read in conjunction with the MD&A presented in the 2014 Annual Report, the 2014 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, 2014.

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 and nine months ended December 31, 2014 was $203 million and $368 million, respectively, and was $24 million and $5 million lower, respectively, than the same periods in the prior fiscal year primarily due to higher energy costs and higher amortization and depreciation expenses, partially offset by higher domestic revenues resulting from higher average customer rates.
- The system inflow energy equivalent for the nine months ended December 31, 2014 was 98 per cent of average, with Williston and Kinbasket reservoir inflows at 89 and 108 per cent of average, respectively. The current system inflow energy for fiscal 2015 is forecast to be 99 per cent of average, while the system inflow energy for the previous fiscal year was 95 per cent of average.
- Capital expenditures for the three and nine months ended December 31, 2014 were $629 million and $1,589 million, respectively. BC Hydro continues to invest significantly in capital projects to refurbish its ageing infrastructure and build new assets for future growth, including the John Hart Generating Station Replacement, Mica Units 5 & 6 Installation, Ruskin Dam and Powerhouse Upgrade, Interior to Lower Mainland Transmission, Iskut Extension, Dawson Creek/Chetwynd Area Transmission, and Northwest Transmission Line projects.
- In December 2014, the Site C project was approved by the Provincial Government. Site C will be a third dam and hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years.

	For the three months ended December 31			*For the nine months ended December 31*		
($ in millions)	**2014**	2013	Change	**2014**	2013	Change
Net Income	**$ 203**	$ 227	$ (24)	**$ 368**	$ 373	$ (5)
Accrued Payment to the Province	**$ 86**	$ -	$ 86	**$ 86**	$ -	$ 86
Number of Domestic Customers	**N/A**	N/A	N/A	**1,929,225**	1,910,054	19,171
GWh Sold (Domestic)	**13,670**	13,952	(282)	**37,534**	38,230	(696)
Total Reservoir Storage (GWh)	**N/A**	N/A	N/A	**24,910**	22,185	2,725

($ in millions)	As at December 31, 2014	As at March 31, 2014	Change
Total Assets	$ **26,799**	$ 25,711	$ 1,088
Retained Earnings	$ **4,033**	$ 3,751	$ 282
Debt to Equity	**80 : 20**	80 : 20	N/A

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, 2014, transfers resulted in a net addition to regulatory accounts of $165 million and $244 million, respectively, primarily due to additions to the energy deferral accounts, Rate Smoothing regulatory account, the IFRS Property, Plant and Equipment regulatory account, and planned expenditures on demand-side management projects (DSM) and the Site C project. These additions were partially offset by transfers to the Finance Charges regulatory liability account and net amortization of the regulatory accounts.

Net income for the three and nine months ended December 31, 2014 was $203 million and $368 million, respectively, and was $24 million and $5 million lower, respectively, than the same periods in the prior fiscal year primarily due to higher energy costs and higher amortization and depreciation expenses, partially offset by higher domestic revenues resulting from higher average customer rates.

REVENUES

Total revenues for the three months ended December 31, 2014 were $1,481 million, an increase of $110 million or 8 per cent compared to the same period in the prior fiscal year. Total revenues for the nine months ended December 31, 2014 were $4,193 million, an increase of $345 million or 9 per cent compared to the same period in the prior fiscal year. The increase in both periods was primarily due to higher domestic revenues resulting from higher average customer rates.

	(in millions)		*(gigawatt hours)*		*($ per MWh)*[2]	
For the three months ended December 31	**2014**	2013	**2014**	2013	**2014**	2013
Domestic						
Residential	**$ 495**	$ 479	**4,895**	5,127	**$101.12**	$ 93.43
Light industrial and commercial	**405**	377	**4,690**	4,683	**86.35**	80.50
Large industrial	**184**	176	**3,551**	3,638	**51.82**	48.38
Other energy sales	**74**	69	**534**	504	**138.58**	136.90
Total Domestic Revenue Before Regulatory Transfer	**1,158**	1,101	**13,670**	13,952	**84.71**	78.91
Rate smoothing and load variance regulatory transfer	**132**	64	**-**	-	**-**	-
Total Domestic	**$ 1,290**	$ 1,165	**13,670**	13,952	**$ 94.37**	$ 83.50
Trade						
Electricity - Gross	**$ 190**	$ 226	**4,022**	4,361	**$ 47.24**	$ 51.82
Less: forward electricity purchases	**(40)**	(64)	**-**	-	**-**	-
Electricity - Net	**150**	162	**-**	-	**-**	-
Gas - Gross	**220**	264	**5,098**	6,910	**43.15**	38.21
Less: forward gas purchases	**(179)**	(220)	**-**	-	**-**	-
Gas - Net	**41**	44	**-**	-	**-**	-
Total Trade[1]	**$ 191**	$ 206	**9,120**	11,271	**$ 20.94**	$ 18.28
Total Revenues	**$ 1,481**	$ 1,371	**22,790**	25,223	**$ 64.98**	$ 54.36

	(in millions)		*(gigawatt hours)*		*($ per MWh)*[2]	
For the nine months ended December 31	**2014**	2013	**2014**	2013	**2014**	2013
Domestic						
Residential	**$ 1,203**	$ 1,129	**12,084**	12,307	**$ 99.55**	$ 91.74
Light industrial and commercial	**1,186**	1,091	**13,736**	13,554	**86.34**	80.49
Large industrial	**547**	497	**10,601**	10,384	**51.60**	47.86
Other energy sales	**203**	206	**1,113**	1,985	**182.39**	103.78
Total Domestic Revenue Before Regulatory Transfer	**3,139**	2,923	**37,534**	38,230	**83.63**	76.46
Rate smoothing and load variance regulatory transfer	**310**	159	**-**	-	**-**	-
Total Domestic	**$ 3,449**	$ 3,082	**37,534**	38,230	**$ 91.89**	$ 80.62
Trade						
Electricity - Gross	**$ 785**	$ 879	**17,135**	19,216	**$ 45.81**	$ 45.74
Less: forward electricity purchases	**(185)**	(236)	**-**	-	**-**	-
Electricity - Net	**600**	643	**-**	-	**-**	-
Gas - Gross	**689**	651	**15,887**	17,766	**43.37**	36.64
Less: forward gas purchases	**(545)**	(528)	**-**	-	**-**	-
Gas - Net	**144**	123	**-**	-	**-**	-
Total Trade[1]	**$ 744**	$ 766	**33,022**	36,982	**$ 22.53**	$ 20.71
Total Revenues	**$ 4,193**	$ 3,848	**70,556**	75,212	**$ 59.43**	$ 51.16

[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, 2014 were $1,290 million, $125 million or 11 per cent higher than the same period in the prior fiscal year. Domestic revenues before regulatory account transfers for the three months ended December 31, 2014 were $1,158 million, $57 million or 5 per cent higher than the same period in the prior fiscal year.

Total domestic revenues after regulatory account transfers for the nine months ended December 31, 2014 were $3,449 million, $367 million or 12 per cent higher than the same period in the prior fiscal year. Domestic revenues before regulatory account transfers for the nine months ended December 31, 2014 were $3,139 million, $216 million or 7 per cent higher than the same period in the prior fiscal year.

The increase before regulatory account transfers for the three and nine months ended December 31, 2014 compared to the same periods in the prior fiscal year was primarily due to higher average customer rates, partially offset by lower consumption overall. Average customer rates were higher in fiscal 2015 compared to the prior fiscal year, reflecting an average rate increase as approved by the BCUC of 9 per cent effective April 1, 2014.

Lower consumption for the three months ended December 31, 2014 compared to the same period in the prior fiscal year was primarily driven by the residential customer class due to warmer weather conditions and the large industrial customer class due to a mill outage and boiler shutdowns at various sites in the pulp and paper sector.

Lower consumption for the nine months ended December 31, 2014 compared to the same period in the prior fiscal year was primarily driven by the residential customer class due to warmer weather conditions and lower other energy sales, partially offset by higher consumption by the light industrial and commercial and large industrial customer classes. Other energy sales volumes were lower than the prior fiscal year due to lower water inflows and system constraints in the current fiscal year. Higher consumption by light industrial and commercial customers was mainly due to increased activity in the manufacturing, services, and commercial real estate sectors. Higher gigawatt hours sold to the large industrial customer class was mainly due to the start up and expansion of several metal mines, partially offset by a mill outage and boiler shutdowns at various sites in the pulp and paper sector.

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. In order to smooth out the impacts of rate increases in the 10 year plan, a Rate Smoothing regulatory account is used to mitigate rate impacts over the 10 year period.

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, 2014 were $191 million, a decrease of $15 million or 7 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 volume of physical gas sold and an 8 per cent decrease in the volume of physical electricity sold. The decrease in the volume of physical gas sold was primarily due to lower withdrawals from gas in storage. The decrease in the volume of physical electricity sold was primarily due to lower exports to Alberta.

Total trade revenues for the nine months ended December 31, 2014 were $744 million, a decrease of $22 million or 3 per cent compared with the same period in the prior fiscal year. The decrease in revenue was primarily due to an 11 per cent decrease in the volume of physical electricity sold and an 11 per cent decrease in the volume of physical gas sold. The decrease in the volume of physical electricity sold was primarily due to lower exports to Alberta. The decrease in the volume of physical gas sold was primarily due to lower withdrawals from gas in storage. These decreases were partly offset by a 17 per cent increase in the average natural gas sales price reflecting overall higher natural gas prices in North America.

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, 2014, total operating expenses of $1,112 million and $3,357 million, respectively, were $119 million and $332 million higher, respectively, than in the same periods in the prior fiscal year. The increase in both periods was primarily the result of higher expenditures on electricity and gas purchases and higher amortization and depreciation expenses.

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 for the three months ended December 31, 2014 were $551 million, $56 million or 11 per cent higher than the same period in the prior fiscal year. Total energy costs for the nine months ended December 31, 2014 were $1,681 million, $189 million or 13 per cent higher than the same period in the prior fiscal year. The increase in both periods was primarily due to higher domestic energy purchases mainly due to more Independent Power Producers (IPPs) achieving commercial operations.

	(in millions)		*(gigawatt hours)*		*($ per MWh)*	
For the three months ended December 31	**2014**	2013	**2014**	2013	**2014**[2]	2013[2]
Domestic						
Water rental payments (hydro generation)[1]	**$ 85**	$ 95	**10,929**	12,014	**$ 7.94**	$ 8.42
Purchases from Independent Power Producers	**307**	224	**3,767**	2,975	**81.59**	75.29
Other electricity purchases - Domestic	**1**	32	**44**	724	**25.94**	44.68
Gas for thermal generation	**9**	13	**58**	104	**155.73**	125.34
Transmission charges and other expenses (recoveries)	**25**	(11)	**33**	30	**-**	-
Allocation from (to) trade energy	**14**	(4)	**384**	(3)	**38.13**	34.71
Total Domestic Cost of Energy Before Regulatory Transfers	**441**	349	**15,215**	15,844	**28.99**	22.03
Domestic cost of energy regulatory transfers	**(43)**	(19)	**-**	-	**-**	-
Total Domestic	**$ 398**	$ 330	**15,215**	15,844	**$ 26.13**	$ 20.81
Trade						
Electricity - Gross	**$ 144**	$ 157	**4,398**	4,328	**$ 32.74**	$ 36.28
Less: forward electricity purchases	**(40)**	(64)	**-**	-	**-**	-
Electricity - Net	**104**	93	**-**	-	**-**	-
Remarketed gas - Gross	**199**	250	**5,152**	7,062	**38.63**	35.40
Less: forward gas purchases	**(179)**	(220)	**-**	-	**-**	-
Remarketed gas - Net	**20**	30	**-**	-	**-**	-
Transmission charges and other expenses	**56**	48	**-**	-	**-**	-
Allocation from (to) domestic energy	**(14)**	4	**(384)**	3	**38.13**	34.71
Total Trade Cost of Energy Before Regulatory Transfers	**166**	175	**9,166**	11,393	**22.54**	20.92
Trade net margin regulatory transfer	**(13)**	(10)	**-**	-	**-**	-
Total Trade	**$ 153**	$ 165	**9,166**	11,393	**$ 21.09**	$ 20.05
Total Energy Costs	**$ 551**	$ 495	**24,381**	27,237	**$ 24.25**	$ 20.49

[1] *Total GWh is net of storage exchange.*
[2] *Total cost per MWh includes other electricity purchases at gross cost.*

For the nine months ended December 31	(in millions) 2014	2013	(gigawatt hours) 2014	2013	($ per MWh) 2014[2]	2013[2]
Domestic						
Water rental payments (hydro generation)[1]	$ 253	$ 287	29,490	31,872	$ 8.68	$ 9.27
Purchases from Independent Power Producers	786	611	10,318	8,399	76.21	72.75
Other electricity purchases - Domestic	3	33	93	769	33.75	43.37
Gas for thermal generation	26	32	161	204	161.70	157.08
Transmission charges and other expenses (recoveries)	8	(10)	82	78	-	-
Allocation from trade energy	27	19	728	1,002	35.06	27.39
Total Domestic Cost of Energy Before Regulatory Transfers	1,103	972	40,872	42,324	26.99	22.97
Domestic cost of energy regulatory transfers	(17)	(90)	-	-	-	-
Total Domestic	$ 1,086	$ 882	40,872	42,324	$ 26.57	$ 20.83
Trade						
Electricity - Gross	$ 513	$ 594	17,823	20,078	$ 28.78	$ 29.58
Less: forward electricity purchases	(185)	(236)	-	-	-	-
Electricity - Net	328	358	-	-	-	-
Remarketed gas - Gross	664	616	16,094	18,014	41.26	34.20
Less: forward gas purchases	(545)	(528)	-	-	-	-
Remarketed gas - Net	119	88	-	-	-	-
Transmission charges and other expenses	184	164	-	-	-	-
Allocation to domestic energy	(27)	(19)	(728)	(1,002)	35.06	27.39
Total Trade Cost of Energy Before Regulatory Transfers	604	591	33,189	37,090	23.78	21.29
Trade net margin regulatory transfer	(9)	19	-	-	-	-
Total Trade	$ 595	$ 610	33,189	37,090	$ 23.50	$ 21.81
Total Energy Costs	$ 1,681	$ 1,492	74,061	79,414	$ 25.20	$ 21.29

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 account transfers for the three months ended December 31, 2014 were $398 million, $68 million or 21 per cent higher than the same period in the prior fiscal year. Domestic energy costs before regulatory account transfers for the three months ended December 31, 2014 were $441 million, $92 million or 26 per cent higher than the same period in the prior fiscal year. The increase was primarily due to more IPPs achieving commercial operations and higher deliveries from hydro based IPPs due to higher inflows, higher energy costs from water transactions related to the Non-Treaty Storage Agreement and Libby Coordination Agreement (transmission charges and other expenses), and an increase in net trade energy imports (higher allocation from trade energy) due to opportunities to import at relatively lower market prices. This was partially offset by a reduction in domestic purchases despite low inflows. Due to lower water inflows and system constraints in the current fiscal year, there was less hydro generation resulting in reduced surplus sales.

Total domestic energy costs after regulatory account transfers for the nine months ended December 31, 2014 were $1,086 million, $204 million or 23 per cent higher than the same period in the prior fiscal year. Domestic energy costs before regulatory account transfers for the nine months ended December 31, 2014 were $1,103 million, $131 million or 13 per cent higher than the same period in the prior fiscal year. The increase was primarily due to more IPPs achieving commercial operations and fewer outages due to maintenance, higher energy costs from water transactions related to the Non-Treaty Storage Agreement and Libby Coordination Agreement (transmission charges and other expenses) and an increase in net trade energy imports (higher allocation from trade energy) at relatively higher market prices. This was partially offset by a reduction in domestic purchases despite low inflows due to greater IPP purchases. Due to lower water inflows and system constraints in the current fiscal year, there was less hydro generation resulting in reduced surplus sales.

Water rental payments are based on the prior year's generation and current year's rates. In the prior fiscal year, there was less hydro generated than the year before resulting in lower water rental payments in the current year. Water rental rates are indexed each calendar year based on the annual percentage change in British Columbia's consumer price index.

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, 2014 were $153 million, a decrease of $12 million or 7 per cent compared with the same period in the prior fiscal year. Trade energy costs before regulatory account transfers for the three months ended December 31, 2014 were $166 million, a decrease of $9 million or 5 per cent compared with the same period in the prior fiscal year. The decrease in trade energy costs was primarily due to a 27 per cent decrease in the volume of physical gas purchased consistent with the decrease in the volumes of physical gas sold. In addition, allocation to domestic was higher due to increased net trade energy import opportunities.

Total trade energy costs after regulatory account transfers for the nine months ended December 31, 2014 were $595 million, a decrease of $15 million or 2 per cent compared with the same period in the prior fiscal year. Trade energy costs before regulatory account transfers for the nine months ended December 31, 2014 were $604 million, an increase of $13 million or 2 per cent compared with the same period in the prior fiscal year. The increase was primarily due to a 21 per cent increase in the average natural gas purchase price reflecting overall higher natural gas prices in North America. This increase was partially offset by an 11 per cent decrease in the volume of physical electricity purchased and an 11 per cent decrease in the volume of physical gas purchased, consistent with the decrease in physical electricity volumes and physical gas volumes sold, respectively.

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

Water Inflows

The system inflow energy equivalent for the three months ended December 31, 2014 was 118 per cent of average, with Williston and Kinbasket reservoir inflows at 125 and 146 per cent of average, respectively. The system inflow energy equivalent for the same period in the prior fiscal year was 88 per cent of average (Williston 95 per cent and Kinbasket 88 per cent). Approximately 16 per cent of the system inflow for the fiscal year occurs in the third quarter and is mostly due to rainfall. Despite the dry conditions across the province in the summer and early fall, there were several heavy precipitation events during the quarter which resulted in a system inflow energy equivalent 30 per cent higher compared to the same period in the prior year.

The system inflow energy equivalent for the nine months ended December 31, 2014 was 98 per cent of average, with Williston and Kinbasket reservoir inflows at 89 and 108 per cent of average, respectively. The current system inflow energy for fiscal 2015 is forecast to be 99 per cent of average, while the system inflow energy for the previous fiscal year was 95 per cent of average.

The Williston and Kinbasket reservoirs have been managed such that system energy storage on December 31, 2014 was 22,700 GWh, or 2,500 GWh above the 10 year historic average. This was 2,600 GWh higher than the system energy storage of 20,100 GWh recorded one year earlier. The Williston and Kinbasket reservoir energy contents were 13,600 GWh (100 GWh above the 10 year historic average) and 9,100 GWh (2,400 GWh above the 10 year historic average), respectively, with Williston 900 GWh higher than the prior year and Kinbasket 1,700 GWh higher than the prior 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, 2014 of $120 million and $384 million, respectively, were $12 million and $17 million lower, respectively, than the same periods in the prior fiscal year primarily due to workforce reductions and lower current service pension costs.

MATERIALS AND EXTERNAL SERVICES

Expenditures on materials and external services for the three months ended December 31, 2014 of $135 million were comparable to the same period in the prior fiscal year. Expenditures on materials and external services for the nine months ended December 31, 2014 of $410 million were $15 million lower than the same period in the prior fiscal year primarily due to lower costs associated with energy purchase agreements (EPAs) accounted for as finance leases and a recovery from a third party.

AMORTIZATION AND DEPRECIATION

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, and the amortization of certain regulatory assets and liabilities. For the three and nine months ended December 31, 2014, amortization and depreciation expense was $301 million and $885 million, respectively, $58 million and $151 million higher, respectively, than the same periods in the prior fiscal year. The increase was due to higher property, plant and equipment depreciation due to an increase in assets in service and higher amortization of regulatory accounts. Six regulatory accounts commenced amortization in fiscal 2015.

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, 2014 were $62 million and $165 million, respectively, $10 million and $9 million higher, respectively, than in the same periods in the prior fiscal year. The increase in both periods was primarily due to higher losses incurred on asset disposals and retirements as well as increased grants and taxes expense in the current year.

CAPITALIZED COSTS

Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from operating costs to property, plant and equipment. Overhead costs not eligible for capitalization under IFRS are transferred from operating costs to the IFRS Property, Plant and Equipment (PP&E) regulatory account. 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.

Capitalized costs for the three and nine months ended December 31, 2014 of $57 million and $168 million, respectively, were $7 million and $15 million lower, respectively, than the same periods 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. The fiscal 2015 reduction is equal to 1/10th of the overhead costs not eligible for capitalization under IFRS.

FINANCE CHARGES

Finance charges for the three months ended December 31, 2014 of $166 million were $15 million or 10 per cent higher than the same period in the prior fiscal year. Finance charges for the nine months ended December 31, 2014 of $468 million were $18 million or 4 per cent higher than the same period in the prior fiscal year. The increase in both periods was primarily due to lower planned capitalized interest during construction and higher planned lease charges relating to EPAs accounted for as finance leases. The increase was partially offset by lower planned short term and long term interest rates and lower interest expense on pension plan liabilities resulting from a lower discount rate.

REGULATORY ACCOUNT 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 have the effect of adjusting net income. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC. Net regulatory account transfers for the periods are comprised of the following:

(in millions)	*For the three months ended December 31* **2014**	2013	*For the nine months ended December 31* **2014**	2013
Energy Accounts				
Heritage Deferral	**$ 46**	$ 21	**$ 85**	$ 51
Non-Heritage Deferral	**86**	6	**124**	42
Trade Income Deferral	**14**	8	**11**	191
	146	35	**220**	284
Forecast Variance Accounts				
Finance Charges	**(37)**	(18)	**(80)**	(56)
Rate Smoothing Account	**44**	30	**118**	79
Other	**4**	7	**(10)**	(10)
	11	19	**28**	13
Capital-Like Accounts				
Demand Side Management (DSM)	**35**	27	**74**	73
Site C	**19**	19	**65**	47
Smart Metering and Infrastructure (SMI)	**5**	19	**11**	57
IFRS Property, Plant and Equipment	**40**	45	**118**	135
	99	110	**268**	312
Non-Cash Accounts				
Environmental Provisions	**11**	(3)	**20**	21
First Nations	**2**	6	**9**	36
Other	**2**	2	**5**	5
	15	5	**34**	62
Amortization of regulatory accounts	**(123)**	(83)	**(356)**	(230)
Interest on regulatory accounts	**17**	15	**50**	42
Net change in regulatory accounts	**$ 165**	$ 101	**$ 244**	$ 483

For the three months ended December 31, 2014, net increases to the Company's regulatory accounts were $165 million, $64 million higher than the same period in the prior fiscal year. The increase was primarily due to higher combined Heritage and Non-Heritage deferral account transfers mainly due to lower domestic load and higher domestic energy costs primarily due to higher IPP deliveries, partially offset by higher amortization of regulatory accounts.

For the nine months ended December 31, 2014, net increases to the Company's regulatory accounts were $244 million, $239 million lower than the same period in the prior fiscal year. The decrease was primarily due to the deferral of the Powerex California legal settlement in the prior fiscal year and higher amortization of regulatory accounts in the current fiscal year, partially offset by higher combined Heritage and Non-Heritage deferral account transfers mainly due to lower domestic revenues primarily from lower surplus sales because of lower inflows and system outages, as well as lower domestic load.

The net asset balance in the regulatory asset and liability accounts as at December 31, 2014 was an asset of $4,943 million compared to an asset of $4,699 million as at March 31, 2014. Net additions to the regulatory accounts during the three and nine months ended December 31, 2014 included:

- Increase to the energy deferral accounts primarily due to lower revenues primarily from lower surplus sales because of lower inflows and system outages, as well as lower domestic load;
- Increase to the Rate Smoothing regulatory account for smoothing the rate impact of the F2015-F2016 Revenue Requirements Rate Application;
- Transfers to the IFRS Property, Plant and Equipment regulatory account for smoothing the rate impact of overhead costs eligible for capitalization under CGAAP but not eligible under IFRS as they are not considered directly attributable to the construction of capital assets; and
- Planned expenditures on DSM projects, which support energy conservation, and the Site C project.

These net additions were partially offset by:

- The net amortization of the regulatory accounts; and
- Transfers to the Finance Charges regulatory liability account due to favourable variances to the forecast.

For fiscal 2015, 26 of 28 regulatory accounts, representing approximately 80 per cent of the total regulatory account balance, are being collected in rates over various periods including six regulatory accounts which commenced amortization in fiscal 2015 and resulted in an additional $27 million and $82 million of amortization expense in the three and nine months ended December 31, 2014, respectively, compared to the same periods in the prior fiscal year.

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, 2014 is $86 million (March 31, 2014 - $167 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).

BC HYDRO 10 YEAR PLAN

In November 2013, the Government announced a 10 year plan for BC Hydro. On March 6, 2014, the Government issued Directions No. 6 and 7 to the BCUC to implement the 10 year plan. Direction No. 6 sets BC Hydro's rate increase at 9 per cent for fiscal 2015 and 6 per cent for fiscal 2016 and also specifies the amounts to be amortized from BC Hydro's regulatory accounts in those years. Direction No. 7 caps BC Hydro's rate increases for fiscal 2017, fiscal 2018 and fiscal 2019 at 4.0 per cent, 3.5 per cent and 3.0 per cent, respectively, subject to a BCUC review. The BCUC will also set the rates for the final five years of the plan. In addition, Direction No. 7 sets the ROE at 11.84 per cent for fiscal 2015, fiscal 2016 and fiscal 2017. Furthermore, the Deferral Account Rate Rider will remain at 5 per cent for fiscal 2015 and future years. Starting in fiscal 2018, the annual payment to the Province will be reduced over five years and then be restricted if the payment would result in a debt to equity ratio exceeding 60:40. Allowed net income for fiscal 2018 and future years will increase by inflation.

BC HYDRO F2015-F2016 REVENUE REQUIREMENTS RATE APPLICATION (F15-F16 RRRA)

The F15-F16 RRRA sets rates for fiscal 2015 and fiscal 2016 at 9 per cent and 6 per cent, respectively, and also requested specific amounts to be amortized from BC Hydro's regulatory accounts. In addition, the F15-F16 RRRA requested the approval of two new regulatory accounts; a) the Rate Smoothing Regulatory Account (to smooth out rate increases over the 10 year period of the 10 year plan) and b) the Real Property Sales Regulatory Account to capture the variance between forecast and actual net gains from real property sales. The BCUC issued Order No. G-48-14 on March 24, 2014, approving the application as filed.

RATE DESIGN APPLICATION (RDA)

BC Hydro is preparing its next RDA, which is expected to be filed with the BCUC in the summer of 2015. Among other things, the 2015 RDA will consider and update many of the underlying drivers, analysis and assumptions that impact BC Hydro's conservation rates for residential, commercial and industrial customers. Government policy, BC Hydro's load resource balance and energy surplus, conservation results and customer experience with the rates will be considered, and may result in amendments or updates to the rates. BC Hydro will also consider the Industrial Electricity Policy Review recommendations with respect to the transmission stepped rate and transmission time of use rates, as well as changes to BC Hydro's long run marginal cost which is used in the pricing of step (tier) 2 energy blocks for the conservation rates.

AVAILABLE TRANSFER CAPACITY (ATC) RULE

In December 2011, the Alberta Electric System Operator (AESO) filed a proposed rule with the Alberta Utilities Commission (AUC) to allocate ATC between the existing BC - Alberta intertie and new interties when the Alberta system is constrained and cannot accommodate the total ATC of all interties. BC Hydro participated in the hearing opposing the proposed rule. The AUC issued its decision on February 1, 2013 approving the rule as filed. The impact to BC Hydro of the approval of the ATC rule is a reduction in the effective transmission transfer capability between the provinces, which in turn reduces the ability of transmission customers, including Powerex, to sell energy into Alberta. On March 4, 2013, BC Hydro and Powerex filed a motion for leave to appeal the AUC decision with the Alberta Court of Appeal. BC Hydro and Powerex also filed a request for Review and Variance with the AUC on April 2, 2013. On August 16, 2013, the AUC issued its decision denying the request for Review and Variance. The motions for leave to appeal were heard on November 19, 2013 and on April 10, 2014, the Alberta Court of Appeal granted leave. BC Hydro and Powerex filed a Notice of Appeal on May 15, 2014 and the appeal was heard on January 15, 2015 with a decision expected by end of fiscal 2015.

BCUC REVIEW TASK FORCE

On April 28, 2014, the Province announced the establishment of a Task Force to review the operations of the BCUC. Terms of Reference were issued the same day and focus on providing recommendations to make the BCUC more effective and efficient. BC Hydro provided input to the Task Force as determined by the schedule established by the Task Force for its review. The Task Force released its final Consultation Summary on September 29, 2014 and on October 1, 2014 released its Interim Report for comments. As per the Terms of Reference for the Task Force, the final report to the Minister was completed by November 17, 2014. On February 4, 2015, the Government released the Independent Review of the B.C. Utilities Commission Report. The report contains 35 recommendations to improve the governance, processes and performance of the Commission.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the nine months ended December 31, 2014 was $558 million, compared with cash flow provided by operating activities of $301 million in the prior fiscal year. The increase was primarily due to the cash transfer to funds held in trust in the prior year for the legal settlement, and net income before regulatory transfers due to higher revenues, partially offset by higher energy costs.

The long-term debt balance net of sinking funds at December 31, 2014 was $16,646 million, compared with $15,568 million at March 31, 2014. The increase was mainly as a result of an increase in long-term bond issues totaling $1,256 million ($1,365 million par value), an increase in revolving borrowings of $111 million and net foreign exchange revaluation of $49 million. These increases were partially offset by long-term bond redemptions totaling $325 million par value. Long-term debt increased primarily to fund capital expenditures.

CAPITAL EXPENDITURES

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

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2014**	2013	**2014**	2013
Distribution system improvements and expansion	**$ 82**	$ 113	**$ 272**	$ 306
Generation replacements and expansion	**130**	118	**373**	329
Transmission lines and substations replacements & expansion	**358**	261	**808**	723
General, including technology, vehicles and buildings	**59**	61	**136**	152
Total Capital Expenditures	**$ 629**	$ 553	**$ 1,589**	$ 1,510

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

Distribution capital expenditures include expenditures on customer driven work, end of life asset replacement, system expansion and improvement, and the Smart Metering and Infrastructure projects.

Generation capital expenditures include expenditures for John Hart Generating Station Replacement, Mica Units 5 & 6 Installation, Ruskin Dam Safety and Powerhouse Upgrade, G.M. Shrum Units 1 to 5 Turbine Rehabilitation, Hugh Keenleyside Spillway Gate Upgrade, and Mica Gas Insulated Switchgear projects.

Transmission lines and substation capital expenditures include expenditures on the Interior to Lower Mainland Transmission Line, Iskut Extension, Dawson Creek/Chetwynd Area Transmission, Northwest Transmission Line, Merritt Area Transmission, Surrey Area and Silverdale substation projects.

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

SITE C

In December 2014, the Site C project was approved by the Provincial Government. Site C will be a third dam and hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort. St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years. The capital cost estimate was increased from $7,900 million to $8,335 million to reflect costs associated with the change from the harmonized sales tax to the provincial sales tax and an adjusted construction start date of summer 2015. This cost estimate excludes the project reserve of $440 million which is held by the Provincial Treasury Board.

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 F15-F16 RRRA.

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 under Electricity Purchase Agreement contracts.

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's objective is 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, 2014. 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 2014 forecasted net income for fiscal 2015 at $582 million, which is consistent with the 10 year plan announced by the Government in November 2013.

BC Hydro filed an updated forecast with the Province in January 2015 which is incorporated into the February 2015 Service Plan and forecasts a net income of $588 million for fiscal 2015 and $653 million for fiscal 2016.

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 2016 assumes average water inflows (100 per cent of average), domestic sales load of 55,379 GWh, average market energy prices of US $32.22/MWh, short-term interest rates of 1.32 per cent and a U.S. dollar exchange rate of US$0.8561.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	*For the three months ended December 31* **2014**	2013	*For the nine months ended December 31* **2014**	2013
Revenues				
Domestic	**$ 1,290**	$ 1,165	**$ 3,449**	$ 3,082
Trade	**191**	206	**744**	766
	1,481	1,371	**4,193**	3,848
Expenses				
Operating expenses (Note 4)	**1,112**	993	**3,357**	3,025
Finance charges (Note 5)	**166**	151	**468**	450
Net Income	**203**	227	**368**	373
OTHER COMPREHENSIVE INCOME				
Items Reclassified Subsequently to Net Income				
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 17)	**22**	8	**31**	18
Reclassification to income on derivatives designated as cash flow hedges (Note 17)	**(31)**	(27)	**(43)**	(37)
Foreign currency translation gains	**8**	8	**12**	9
Other Comprehensive Loss	**(1)**	(11)	**-**	(10)
Total Comprehensive Income	**$ 202**	$ 216	**$ 368**	$ 363

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* **2014**	*As at March 31* 2014
ASSETS		
Current Assets		
Cash and cash equivalents (Note 7)	**$ 53**	$ 107
Restricted cash (Notes 7 and 12)	**33**	355
Accounts receivable and accrued revenue	**625**	718
Inventories (Note 8)	**177**	114
Prepaid expenses	**117**	211
Current portion of derivative financial instrument assets (Note 17)	**129**	96
	1,134	1,601
Non-Current Assets		
Property, plant and equipment (Note 9)	**19,583**	18,525
Intangible assets (Note 9)	**510**	501
Regulatory assets (Note 10)	**5,207**	4,928
Derivative financial instrument assets (Note 17)	**71**	27
Other non-current assets (Note 11)	**294**	129
	25,665	24,110
	$ 26,799	$ 25,711
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Notes 12 and 16)	**$ 1,257**	$ 1,886
Current portion of long-term debt (Note 13)	**4,024**	4,087
Current portion of derivative financial instrument liabilities (Note 17)	**89**	76
	5,370	6,049
Non-Current Liabilities		
Long-term debt (Note 13)	**12,762**	11,610
Regulatory liabilities (Note 10)	**264**	229
Derivative financial instrument liabilities (Note 17)	**51**	55
Contributions in aid of construction	**1,570**	1,291
Post-employment benefits	**1,173**	1,173
Other non-current liabilities (Note 16)	**1,462**	1,439
	17,282	15,797
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**4,033**	3,751
Accumulated other comprehensive income	**54**	54
	4,147	3,865
	$ 26,799	$ 25,711

Commitments (Note 9)

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

Approved on Behalf of the Board:

Stephen Bellringer
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, 2013	$ 17	$ 54	$ 71	$ 60	$ 3,369	$ 3,500
Comprehensive Income (Loss)	9	(19)	(10)	-	373	363
Balance, December 31, 2013	$ 26	$ 35	$ 61	$ 60	$ 3,742	$ 3,863
Balance, April 1, 2014	$ 33	$ 21	$ 54	$ 60	$ 3,751	$ 3,865
Payment to the Province	-	-	-	-	(86)	(86)
Comprehensive Income (Loss)	12	(12)	-	-	368	368
Balance, December 31, 2014	$ 45	$ 9	$ 54	$ 60	$ 4,033	$ 4,147

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

	For the nine months ended December 31	
(in millions)	**2014**	2013
Operating Activities		
Net income	**$ 368**	$ 373
Regulatory account transfers (Note 10)	**(600)**	(713)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 10)	**356**	230
Amortization and depreciation expense (Note 6)	**508**	480
Unrealized gains on mark-to-market	**(36)**	(73)
Employee benefit plan expenses	**63**	70
Interest accrual	**500**	479
Other items	**46**	(6)
	1,205	840
Changes in:		
Restricted cash	**322**	(242)
Accounts receivable and accrued revenue	**99**	24
Prepaid expenses	**96**	99
Inventories	**(57)**	16
Accounts payable, accrued liabilities and other non-current liabilities	**(629)**	27
Contributions in aid of construction	**105**	102
	(64)	26
Interest paid	**(583)**	(565)
Cash provided by operating activities	**558**	301
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(1,473)**	(1,444)
Cash used in investing activities	**(1,473)**	(1,444)
Financing Activities		
Long-term debt:		
Issued (Note 13)	**1,256**	1,011
Retired	**(325)**	(706)
Receipt of revolving borrowings	**6,431**	6,533
Repayment of revolving borrowings	**(6,321)**	(5,224)
Payment to the Province (Note 14)	**(167)**	(215)
Settlement of hedging derivatives	**-**	(84)
Other items	**(13)**	(12)
Cash provided by financing activities	**861**	1,303
Increase (decrease) in cash and cash equivalents	**(54)**	160
Cash and cash equivalents, beginning of period	**107**	60
Cash and cash equivalents, end of period	**$ 53**	$ 220

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 10.

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 disclosed in BC Hydro's 2014 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 2014 Annual Report. Certain amounts in the prior year's comparative figures have been reclassified to conform to the current year's presentation.

These condensed consolidated interim financial statements were approved by the Board of Directors on January 29, 2015.

NOTE 3: CHANGE IN ACCOUNTING POLICIES

Standards that have been adopted effective April 1, 2014 that have little or no impact on the consolidated financial statements include:

- Amendments to IFRS 10, *Consolidated Financial Statements*
- Amendments to IFRS 12, *Disclosure of Interests in Other Entities*
- Amendments to IAS 27, *Consolidated and Separate Financial Statements*
- Amendments to IAS 32, *Financial Instruments: Presentation*
- Amendments to IAS 36, *Impairment of Assets*
- Amendments to IAS 39, *Financial Instruments: Recognition and Measurement*
- IFRIC 21, *Levies*

Effective April 1, 2014, the Company elected to change its accounting policy for measurement of natural gas inventory held in storage for trading purposes from the lower of weighted average cost and net realizable value to fair value less costs to sell using the one-month forward price of natural gas and included in Level 2 of the fair value hierarchy (Note 17: Financial Instruments – Fair Value Hierarchy). Changes in fair value are recognized in trade revenues. Management believes fair value less costs to sell provides a more relevant measure of performance in natural gas trading activities. The change in accounting policy has no material impact on initial adoption or in the comparative period.

NOTE 4: OPERATING EXPENSES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2014**	2013	**2014**	2013
Electricity and gas purchases	**$ 427**	$ 340	**$ 1,310**	$ 1,080
Water rentals	**89**	104	**267**	271
Transmission charges	**35**	51	**104**	141
Personnel expenses	**120**	132	**384**	401
Materials and external services	**135**	135	**410**	425
Amortization and depreciation (Note 6)	**301**	243	**885**	734
Grants, taxes and other costs	**62**	52	**165**	156
Capitalized costs	**(57)**	(64)	**(168)**	(183)
	$ 1,112	$ 993	**$ 3,357**	$ 3,025

NOTE 5: FINANCE CHARGES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2014**	2013	**2014**	2013
Interest on long-term debt	**$ 175**	$ 184	**$ 512**	$ 549
Interest on finance lease liabilities	**25**	11	**54**	34
Net interest expense on net defined benefit liability	**-**	3	**2**	10
Less: capitalized interest	**(17)**	(26)	**(51)**	(79)
Total finance costs	**183**	172	**517**	514
Other recoveries	**(17)**	(21)	**(49)**	(64)
	$ 166	$ 151	**$ 468**	$ 450

NOTE 6: AMORTIZATION AND DEPRECIATION

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2014**	2013	**2014**	2013
Depreciation of property, plant and equipment	**$ 154**	$ 137	**$ 461**	$ 434
Amortization of intangible assets	**16**	16	**47**	46
Amortization of regulatory accounts	**131**	90	**377**	254
	$ 301	$ 243	**$ 885**	$ 734

NOTE 7: CASH AND CASH EQUIVALENTS AND RESTRICTED CASH

CASH AND CASH EQUIVALENTS

(in millions)	***As at December 31*** **2014**	*As at March 31* 2014
Cash	**$ 49**	$ 74
Short-term investments	**4**	33
	$ 53	$ 107

RESTRICTED CASH

(in millions)	***As at December 31*** **2014**	*As at March 31* 2014
Funds held in trust (Note 12)	**$ -**	$ 302
Other	**33**	53
	$ 33	$ 355

Other restricted cash represents cash balances to which the Company does not have immediate access as they have been pledged to counterparties as security for investments or trade obligations. These balances are available to the Company only upon liquidation of the investments or settlement of the trade obligations for which they have been pledged as security.

NOTE 8: INVENTORIES

(in millions)	***As at December 31* 2014**	*As at March 31* 2014
Materials and supplies	**$ 118**	$ 111
Natural gas trading inventories	**59**	3
	$ 177	$ 114

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

NOTE 9: PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Property, plant and equipment and intangible asset expenditures for the three and nine months ended December 31, 2014 were $629 million and $1,589 million, respectively (2013 - $553 million and $1,510 million, respectively).

As of December 31, 2014, the Company has contractual commitments to spend $1,310 million on major property, plant and equipment projects (for individual projects greater than $50 million).

NOTE 10: 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, 2014, the impact of regulatory accounting has resulted in net increases of $165 million and $244 million, respectively, to comprehensive income (three and nine months ended December 31, 2013 - $101 million increase and $483 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 decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to comprehensive income.

(in millions)	*April 1 2014*	*Addition (Reduction)*	*Amortization*	*Net Change*	*December 31 2014*
Regulatory Assets					
Heritage Deferral Account	$ 105	$ 88	$ (19)	$ 69	$ 174
Non-Heritage Deferral Account	362	135	(66)	69	431
Trade Income Deferral Account	324	19	(58)	(39)	285
Demand-Side Management Programs	788	74	(53)	21	809
First Nation Negotiations,					
Litigation & Settlement Costs	589	14	(32)	(18)	571
Non-Current Pension Cost	280	(6)	(25)	(31)	249
Site C	338	77	-	77	415
CIA Amortization Variance	81	5	-	5	86
Environmental Provisions	383	22	(52)	(30)	353
Smart Metering and Infrastructure	277	19	(23)	(4)	273
IFRS Pension & Other					
Post-Employment Benefits	688	-	(28)	(28)	660
IFRS Property, Plant and Equipment	617	118	(12)	106	723
Rate Smoothing	-	118	-	118	118
Other Regulatory Accounts	96	1	(37)	(36)	60
Total Regulatory Assets	4,928	684	(405)	279	5,207
Regulatory Liabilities					
Future Removal and Site Restoration Costs	56	-	(21)	(21)	35
Foreign Exchange Gains and Losses	89	(6)	-	(6)	83
Finance Charges	79	79	(19)	60	139
Other Regulatory Accounts	5	11	(9)	2	7
Total Regulatory Liabilities	229	84	(49)	35	264
Net Regulatory Asset	$ 4,699	$ 600	$ (356)	$ 244	$ 4,943

As part of the 10 year plan announced by Government, the Rate Smoothing Regulatory Account was established under Direction No. 7 to defer, for recovery in future years (over the period of the 10 year plan), those portions of BC Hydro's revenue requirement in a particular fiscal year, that are not recovered in rates in that particular fiscal year.

OTHER REGULATORY ACCOUNTS

Other regulatory asset and liability accounts with individual balances less than $40 million include Capital Project Investigation Costs and the Home Purchase Option Program.

NOTE 11: OTHER NON-CURRENT ASSETS

(in millions)	***As at December 31 2014***	*As at March 31* 2014
Sinking funds	**$ 140**	$ 129
Non-current receivable	**154**	-
	$ 294	$ 129

NON-CURRENT RECEIVABLE

In July 2014, the Company recorded a receivable, at fair value, of $162 million ($10 million included in accounts receivable and accrued revenue and $152 million in other non-current assets) for contributions in aid of the construction of the Northwest Transmission Line. The contributions will be received in 19 annual payments of approximately $10 million, adjusted for inflation. The fair value of the receivable was measured using an estimated inflation rate and 4.6 per cent discount rate. The contributions in aid of construction will be amortized over the 60 year term of the customer contract.

NOTE 12: ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(in millions)	***As at December 31 2014***	*As at March 31* 2014
Accounts payable	**$ 246**	$ 386
Accrued liabilities	**719**	819
Legal settlement	**-**	302
Current portion of other non-current liabilities (Note 16)	**124**	120
Dividend payable	**86**	167
Other	**82**	92
	$ 1,257	$ 1,886

LEGAL SETTLEMENT

On October 4, 2013, the Federal Energy Regulatory Commission (FERC) issued an Order approving the settlement between Powerex and Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, the California Attorney General, and the California Public Utilities Commission (the California Parties) arising from events and transactions in the California power market during the 2000 and 2001 period.

As part of the settlement, Powerex made a net cash payment of US$273 million into escrow in fiscal 2014 which translated to CDN$302 million as at March 31, 2014. Notice of the Settlement Effective Date of July 11, 2014 was filed by the parties at FERC and the cash was released from escrow on July 25, 2014.

NOTE 13: LONG-TERM DEBT AND DEBT MANAGEMENT

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

In the three month period ended December 31, 2014, the Company did not issue any bonds (2013 - $nil). For the nine month period ended December 31, 2014, the Company issued bonds with net proceeds of $1,256 million and par value of $1,365 million (2013 – net proceeds of $1,011 million and par value of $1,150 million), a weighted average effective interest rate of 3.6 per cent (2013 – 3.9 per cent) and a weighted average term to maturity of 29.9 years (2013 – 29.9 years).

NOTE 14: 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 nine months ended December 31, 2014, there were no changes in the approach to capital management.

The debt to equity ratio at December 31, 2014 and March 31, 2014 was as follows:

(in millions)	*As at December 31* **2014**	*As at March 31* 2014
Total debt, net of sinking funds	**$ 16,646**	$ 15,568
Less: Cash and cash equivalents	**(53)**	(107)
Net Debt	**$ 16,593**	$ 15,461
Retained earnings	**$ 4,033**	$ 3,751
Contributed surplus	**60**	60
Accumulated other comprehensive income	**54**	54
Total Equity	**$ 4,147**	$ 3,865
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 at December 31, 2014 is $86 million (March 31, 2014 - $167 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.

NOTE 15: 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, 2014 was $36 million and $108 million, respectively (2013 - $27 million and $116 million, respectively).

Contributions to the registered defined benefit pension plans for the three and nine months ended December 31, 2014 were $16 million and $48 million, respectively (2013 - $16 million and $31 million, respectively).

NOTE 16: OTHER NON-CURRENT LIABILITIES

(in millions)	***As at December 31* 2014**	*As at March 31* 2014
Provisions		
Environmental liabilities	**$ 325**	$ 333
Decommissioning obligations	**53**	50
Other	**22**	22
	400	405
First Nations liabilities	**412**	417
Finance lease obligations	**263**	276
Other liabilities	**65**	28
Deferred revenue - Skagit River Agreement	**446**	433
	1,586	1,559
Less: Current portion, included in accounts payable and accrued liabilities	**(124)**	(120)
	$ 1,462	$ 1,439

NOTE 17: 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, 2014 and 2013.

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, 2014 and March 31, 2014. 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, 2014 Carrying Value	December 31, 2014 Fair Value	March 31, 2014 Carrying Value	March 31, 2014 Fair Value
Financial Assets and Liabilities at Fair Value Through Profit or Loss:				
Short-term investments	$ 4	$ 4	$ 33	$ 33
Loans and Receivables:				
Accounts receivable and accrued revenue	625	625	718	718
Non-current receivable (long-term portion only)	154	155	-	-
Restricted cash	33	33	355	355
Cash	49	49	74	74
Held to Maturity:				
Sinking funds – US	140	162	129	143
Other Financial Liabilities:				
Accounts payable and accrued liabilities	(1,257)	(1,257)	(1,886)	(1,886)
Revolving borrowings - CAD	(3,732)	(3,732)	(3,504)	(3,504)
Revolving borrowings - US	(141)	(141)	(258)	(258)
Long-term debt (including current portion due in one year)	(12,913)	(15,495)	(11,935)	(13,405)
First Nations liabilities (long-term portion only)	(378)	(962)	(385)	(725)
Finance lease obligations (long-term portion only)	(244)	(244)	(259)	(259)

For non-derivative financial assets and liabilities classified as financial assets and liabilities at fair value through profit or loss, $nil (2013 - $nil and $12 million gain, respectively) has been recognized in net income for the three and nine months ended December 31, 2014 relating to changes in fair value. For short-term investments, loans and receivables, and accounts payable and accrued liabilities, the carrying value 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 2014 Fair Value	March 31 2014 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)	$ (5)	$ (36)
Non-Designated Derivative Instruments:		
Foreign currency contracts	3	5
Commodity derivatives	62	23
	65	28
Net asset (liability)	$ 60	$ (8)

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

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

(in millions)	**December 31 2014**	March 31 2014
Current portion of derivative financial instrument assets	**$ 129**	$ 96
Current portion of derivative financial instrument liabilities	**(89)**	(76)
Derivative financial instrument assets, non-current	**71**	27
Derivative financial instrument liabilities, non-current	**(51)**	(55)
Net asset (liability)	**$ 60**	$ (8)

For designated cash flow hedges for the three and nine months ended December 31, 2014, gains of $22 million and $31 million, respectively, (2013 - $8 million gain and $18 million gain, respectively) were recognized in other comprehensive income. For the three and nine months ended December 31, 2014, $31 million and $43 million, respectively, (2013 - $27 million and $37 million, respectively) were removed from other comprehensive income and reported in net income, offsetting foreign exchange losses (2013 – losses) recorded in the period.

For derivative instruments not designated as hedges, gains of $3 million and $3 million, respectively, (2013 - $1 million gain and $1 million gain, respectively) were recognized in finance charges for the three and nine months ended December 31, 2014 with respect to foreign currency contracts for cash management purposes. For the three and nine months ended December 31, 2014, a loss of $1 million and a loss of $6 million, respectively, (2013 - $35 million gain and $37 million gain, respectively) were recognized in finance charges with respect to foreign currency contracts for U.S. short-term borrowings. These economic hedges offset $5 million of foreign exchange revaluation gains (2013 - $45 million loss) recorded with respect to U.S. short-term borrowings for the nine months ended December 31, 2014. A net gain of $24 million and a net gain of $49 million, respectively, (2013 - $27 million gain and $45 million gain, respectively) were recorded in trade revenue for the three and nine months ended December 31, 2014 with respect to commodity derivatives.

INCEPTION GAINS AND LOSSES

Changes in deferred inception gains and losses arising from the determination of fair value of derivative financial instruments which are not supported by observable current market transactions or valuation models using only observable market data are as follows:

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2014**	2013	**2014**	2013
Unamortized gain at beginning of period	**$ (46)**	$ (47)	**$ (50)**	$ (58)
New transactions	**(29)**	(2)	**(35)**	(4)
Amortization	**-**	6	**10**	19
Unamortized gain at end of period	**$ (75)**	$ (43)	**$ (75)**	$ (43)

FAIR VALUE HIERARCHY

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

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

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

The following table presents the financial assets and financial liabilities measured at fair value for each hierarchy level as at December 31, 2014 and March 31, 2014:

As at December 31, 2014 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 4	$ -	$ -	$ 4
Derivatives designated as hedges	-	27	-	27
Derivatives not designated as hedges	71	89	13	173
Total financial assets carried at fair value	$ 75	$ 116	$ 13	$ 204
Derivatives designated as hedges	$ -	$ (32)	$ -	$ (32)
Derivatives not designated as hedges	(60)	(42)	(6)	(108)
Total financial liabilities carried at fair value	$ (60)	$ (74)	$ (6)	$ (140)

As at March 31, 2014 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 33	$ -	$ -	$ 33
Derivatives designated as hedges	-	18	-	18
Derivatives not designated as hedges	21	35	49	105
Total financial assets carried at fair value	$ 54	$ 53	$ 49	$ 156
Derivatives designated as hedges	$ -	$ (54)	$ -	$ (54)
Derivatives not designated as hedges	(22)	(49)	(6)	(77)
Total financial liabilities carried at fair value	$ (22)	$ (103)	$ (6)	$ (131)

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 nine months ended December 31, 2014 and 2013:

(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**

(in millions)		
Balance at April 1, 2013	**$**	**34**
Cumulative impact of net gain recognized		18
New transactions		13
Existing transactions settled		(15)
Balance at December 31, 2013	**$**	**50**

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.

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.

A net loss of $23 million and $9 million, respectively, (2013 – net gains of $7 million and $28 million, respectively) recognized in net income during the three and nine months ended December 31, 2014 relate to Level 3 financial instruments held at December 31, 2014. The net gain is recognized in trade revenue.

The Company believes that the use of reasonable alternative valuation input assumptions in the calculation of Level 3 fair values would not result in significantly different fair values. 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 quarterly basis.

NOTE 18: 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.

GDS15-002