BC HYDRO THIRD QUARTER REPORT FISCAL 2014

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, 2013 and should be read in conjunction with the MD&A presented in the 2013 Annual Report, the 2013 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, 2013.

The Company applies accounting standards as prescribed by the Province of British Columbia ("the Province") which applies the accounting principles of International Financial Reporting Standards (IFRS) except that the Company applies 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, 2013 was $227 million and $373 million, respectively, and was $15 million and $33 million higher, respectively, than the same periods in the prior fiscal year due to higher domestic and trade revenues resulting from higher electricity and gas prices partially offset by lower gigawatt hours sold and higher amortization and depreciation expense due to higher assets in service.
- The forecast system inflow energy equivalent for fiscal 2014 is 95 per cent of average, with Williston and Kinbasket reservoirs at 92 and 106 per cent of average, respectively. The system inflow energy equivalent for fiscal 2013 was 109 per cent of average, but actual inflows were higher because both Williston and Kinbasket reservoirs spilled surplus water; in addition, there was some economic spill due to negative market prices. In contrast, fiscal 2014 is experiencing below average inflows and higher market prices.
- Capital expenditures for the three and nine months ended December 31, 2013 were $553 million and $1,510 million, respectively. BC Hydro continues to invest significantly to refurbish its ageing infrastructure and build new assets for future growth, including the Mica Units 5 & 6 Project, G.M. Shrum Units 1 to 5 Turbine Rehabilitation, Ruskin Dam and Powerhouse Upgrade, Smart Metering and Infrastructure (SMI), Northwest Transmission Line Project, Interior to Lower Mainland Transmission Project, and Vancouver City Central Transmission Project.

	For the three months ended December 31			*For the nine months ended December 31*		
(in millions)	**2013**	2012	Change	**2013**	2012	Change
Net Income	**$ 227**	$ 212	$ 15	**$ 373**	$ 340	$ 33
Number of Domestic Customers	**N/A**	N/A	N/A	**1,910,054**	1,887,281	22,773
GWh Sold (Domestic)	**13,952**	13,957	(5)	**38,230**	42,266	(4,036)
Total Reservoir Storage (GWh)	**N/A**	N/A	N/A	**22,185**	24,608	(2,423)

(in millions)	As at December 31, 2013	As at March 31, 2013	Change
Total Assets	$ 25,563	$ 23,782	$ 1,781
Retained Earnings	$ 3,742	$ 3,369	$ 373
Debt to Equity	80 : 20	80 : 20	N/A

CONSOLIDATED RESULTS OF OPERATIONS

These interim statements represent the Company's presentation of its 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 the principles of 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, 2013, net transfers resulted in a net addition to regulatory accounts of $101 million and $483 million, respectively, primarily due to the California litigation settlement which resulted in an increase to the Trade Income Deferral Account (TIDA) of $214 million. Other increases included deferral of costs for future recovery in rates including demand-side management programs (DSM), Site C and SMI, and the phasing in of the rate impact of the reduction in the amount of overhead eligible for capitalization under the principles of IFRS as compared to Canadian generally accepted accounting principles (CGAAP).

Net income after regulatory transfers for the three and nine months ended December 31, 2013 was $227 million and $373 million, respectively, $15 million and $33 million higher, respectively, than the same periods in the prior fiscal year. Higher domestic and trade revenues resulting from higher electricity and gas prices were partially offset by lower gigawatt hours sold and higher amortization and depreciation expense due to higher assets in service.

REVENUES

Total revenue for the three months ended December 31, 2013 was $1,371 million, an increase of $86 million or seven per cent compared to the same period in the prior fiscal year. Total revenue for the nine months ended December 31, 2013 was $3,848 million, an increase of $377 million or 11 per cent compared to the same period in the prior fiscal year. The increase in both periods was primarily due to higher domestic and trade revenues resulting from higher electricity and gas prices, partially offset by lower gigawatt hours sold.

	(in millions)		*(gigawatt hours)*		*($ per MWh)*[2]	
For the three months ended December 31	**2013**	2012	**2013**	2012	**2013**	2012
Domestic						
Residential	**$ 479**	$ 458	**5,127**	5,018	**$ 93.43**	$ 91.27
Light industrial and commercial	**377**	364	**4,683**	4,640	**80.50**	78.45
Large industrial	**176**	159	**3,638**	3,407	**48.38**	46.67
Other energy sales	**69**	66	**504**	892	**136.90**	73.99
Total Domestic Revenue Before Regulatory Transfer	**1,101**	1,047	**13,952**	13,957	**78.91**	75.02
Rate smoothing and load variance regulatory transfer	**64**	38	**–**	–	**–**	–
Total Domestic	**$ 1,165**	$ 1,085	**13,952**	13,957	**$ 83.50**	$ 77.74
Trade						
Electricity - Gross	**$ 226**	$ 200	**4,361**	5,599	**$ 51.82**	$ 35.72
Less: forward electricity purchases	**(64)**	(46)	**–**	–	**–**	–
Electricity - Net	**162**	154	**–**	–	**–**	–
Gas - Gross	**264**	253	**6,910**	7,267	**38.21**	34.81
Less: forward gas purchases	**(220)**	(207)	**–**	–	**–**	–
Gas - Net	**44**	46	**–**	–	**–**	–
Total Trade[1]	**$ 206**	$ 200	**11,271**	12,866	**$ 18.28**	$ 15.54
Total	**$ 1,371**	$ 1,285	**25,223**	26,823	**$ 54.36**	$ 47.91

	(in millions)		*(gigawatt hours)*		*($ per MWh)*[2]	
For the nine months ended December 31	**2013**	2012	**2013**	2012	**2013**	2012
Domestic						
Residential	**$ 1,129**	$ 1,093	**12,307**	12,124	**$ 91.74**	$ 90.15
Light industrial and commercial	**1,091**	1,058	**13,554**	13,562	**80.49**	78.01
Large industrial	**497**	472	**10,384**	10,168	**47.86**	46.42
Other energy sales	**206**	236	**1,985**	6,412	**103.78**	36.81
Total Domestic Revenue Before Regulatory Transfer	**2,923**	2,859	**38,230**	42,266	**76.46**	67.64
Rate smoothing and load variance regulatory transfer	**159**	7	**–**	–	**–**	–
Total Domestic	**$ 3,082**	$ 2,866	**38,230**	42,266	**$ 80.62**	$ 67.81
Trade						
Electricity - Gross	**$ 879**	$ 675	**19,216**	24,924	**$ 45.74**	$ 27.08
Less: forward electricity purchases	**(236)**	(165)	**–**	–	**–**	–
Electricity - Net	**643**	510	**–**	–	**–**	–
Gas - Gross	**651**	539	**17,766**	20,589	**36.64**	26.18
Less: forward gas purchases	**(528)**	(444)	**–**	–	**–**	–
Gas - Net	**123**	95	**–**	–	**–**	–
Total Trade[1]	**$ 766**	$ 605	**36,982**	45,513	**$ 20.71**	$ 13.29
Total	**$ 3,848**	$ 3,471	**75,212**	87,779	**$ 51.16**	$ 39.54

[1] *Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer.*

[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 transfers for the three months ended December 31, 2013 were $1,165 million, an increase of $80 million or seven per cent compared to the same period in the prior fiscal year. Total domestic revenues after regulatory transfers for the nine months ended December 31, 2013 were $3,082 million, an increase of $216 million or eight per cent compared to the same period in the prior fiscal year.

Domestic revenues after regulatory transfers were higher in the three and nine months ended December 31, 2013 compared to the same periods in the prior fiscal year due mainly to higher gigawatt hours sold to residential and large industrial customer classes and higher average customer rates, partially offset by lower other energy sales. Average customer rates were higher in fiscal 2014 compared to the prior fiscal year, reflecting an average rate increase as approved by the BCUC of 1.44 per cent.

Gigawatt hours sold were higher in the residential class primarily driven by customer growth and the impact of colder weather, partially offset by lower usage per account. Higher gigawatt hours sold to the large industrial customer class was mainly due to the start up and expansion of metal mines. Other energy sales were significantly lower than the prior fiscal year due to unusually high water inflows in the prior fiscal year. Surplus energy sales were 48 GWh and 1,009 GWh in the three and nine months ended December 31, 2013, respectively, compared to 450 GWh and 5,487 GWh in the same periods of the prior fiscal year, respectively.

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 both 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 revenue of $206 million for the three months ended December 31, 2013 was comparable with total trade revenue of $200 million in the same period in the prior fiscal year.

Total trade revenue for the nine months ended December 31, 2013 was $766 million, an increase of $161 million compared with the same period in the prior fiscal year. The increase in revenue was primarily due to a 58 per cent increase in the average electricity sales price and a 38 per cent increase in the average gas sales price. The increase in the average electricity sales price in current year was primarily due to low market prices in the Pacific Northwest in the prior year due to higher water levels. The increase in the average gas sales price in the current fiscal year reflects increases in natural gas prices in North America due to increased demand. These increases were partially offset by a 19 per cent reduction in gigawatt hours sold over the same period in the prior year primarily due to lower volumes of surplus energy sold from BC Hydro as a result of lower water levels. Variances between actual and planned trade income (which includes trade revenues) are deferred to the TIDA.

OPERATING EXPENSES

Total operating expenses for the three and nine months ended December 31, 2013 were $993 million and $3,025 million, respectively, $57 million and $299 million, respectively, higher 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, consistent with higher electricity and gas sales, and higher amortization and depreciation expense primarily due to higher assets in service.

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 account transfers, for the three months ended December 31, 2013 were $495 million, $56 million or 13 per cent higher than in the same period in the prior fiscal year. Total energy costs, after regulatory account transfers, for the nine months ended December 31, 2013 were $1,492 million, $247 million or 20 per cent higher than in the same period in the prior fiscal year. The increase in both periods over the prior fiscal year was primarily due to lower water inflows and system constraints in the current fiscal year, more Independent Power Producers (IPPs) achieving commercial operations, higher thermal generation, higher trade electricity purchase prices, and higher trade gas purchase prices, partially offset by fewer surplus sales.

	(in millions)		*(gigawatt hours)*		*($ per MWh)*	
For the three months ended December 31	**2013**	2012	**2013**	2012	**2013**[3]	2012[3]
Domestic						
Water rental payments (hydro generation)[1]	**$ 95**	$ 85	**12,014**	13,159	**$ 8.42**	$ 6.54
Purchases from Independent Power Producers	**224**	196	**2,975**	2,722	**75.29**	72.01
Other electricity purchases - Domestic	**32**	3	**724**	122	**44.68**	23.87
Gas for thermal generation	**13**	8	**104**	43	**125.34**	177.43
Transmission charges and other expenses (recoveries)	**(11)**	8	**30**	30	**–**	–
Allocation (to) from trade energy	**(4)**	(6)	**(3)**	(260)	**34.71**	21.99
Total Domestic Cost of Energy Before Regulatory Transfers	**349**	294	**15,844**	15,816	**22.03**	18.58
Domestic cost of energy regulatory transfers	**(19)**	(2)	**–**	–	**–**	–
Total Domestic	**$ 330**	$ 292	**15,844**	15,816	**$ 20.81**	$ 18.45
Trade						
Electricity - Gross	**$ 157**	$ 136	**4,328**	5,257	**$ 36.28**	$ 25.87
Less: forward electricity purchases[2]	**(64)**	(46)	**–**	–	**–**	–
Electricity - Net	**93**	90	**–**	–	**–**	–
Remarketed gas - Gross	**250**	241	**7,062**	7,287	**35.40**	33.07
Less: forward gas purchases[2]	**(220)**	(207)	**–**	–	**–**	–
Remarketed gas - Net	**30**	34	**–**	–	**–**	–
Transmission charges and other expenses	**48**	43	**–**	–	**–**	–
Allocation from (to) domestic energy	**4**	6	**3**	260	**34.71**	21.99
Total Trade Cost of Energy Before Regulatory Transfers	**175**	173	**11,393**	12,804	**20.92**	17.15
Trade net margin regulatory transfer	**(10)**	(26)	**–**	–	**–**	–
Total Trade	**$ 165**	$ 147	**11,393**	12,804	**$ 20.05**	$ 15.10
Total Energy Costs	**$ 495**	$ 439	**27,237**	28,620	**$ 20.49**	$ 16.95

For the nine months ended December 31	(in millions) 2013	2012	(gigawatt hours) 2013	2012	($ per MWh) 2013[3]	2012[3]
Domestic						
Water rental payments (hydro generation)[1]	**$ 287**	$ 256	**31,872**	37,745	**$ 9.27**	$ 6.82
Purchases from Independent Power Producers	**611**	579	**8,399**	8,311	**72.75**	69.67
Other electricity purchases - Domestic	**33**	4	**769**	163	**43.37**	24.00
Gas for thermal generation	**32**	22	**204**	90	**157.08**	240.60
Transmission charges and other expenses (recoveries)	**(10)**	(35)	**78**	79	**–**	–
Allocation (to) from trade energy	**19**	(4)	**1,002**	(238)	**27.39**	20.50
Total Domestic Cost of Energy Before Regulatory Transfers	**972**	822	**42,324**	46,150	**22.97**	17.81
Domestic cost of energy regulatory transfers	**(90)**	(11)	**–**	–	**–**	–
Total Domestic	**$ 882**	$ 811	**42,324**	46,150	**$ 20.83**	$ 17.57
Trade						
Electricity - Gross	**$ 594**	$ 376	**20,078**	24,445	**$ 29.58**	$ 15.38
Less: forward electricity purchases[2]	**(236)**	(165)	**–**	–	**–**	–
Electricity - Net	**358**	211	**–**	–	**–**	–
Remarketed gas - Gross	**616**	519	**18,014**	20,733	**34.20**	25.03
Less: forward gas purchases[2]	**(528)**	(444)	**–**	–	**–**	–
Remarketed gas - Net	**88**	75	**–**	–	**–**	–
Transmission charges and other expenses	**164**	162	**–**	–	**–**	–
Allocation from (to) domestic energy	**(19)**	4	**(1,002)**	238	**27.39**	20.50
Total Trade Cost of Energy Before Regulatory Transfers	**591**	452	**37,090**	45,416	**21.29**	12.11
Trade net margin regulatory transfer	**19**	(18)	**–**	–	**–**	–
Total Trade	**$ 610**	$ 434	**37,090**	45,416	**$ 21.81**	$ 11.71
Total Energy Costs	**$ 1,492**	$ 1,245	**79,414**	91,566	**$ 21.29**	$ 14.66

1 *Total GWh is net of storage exchange.*
2 *Other electricity purchases in dollars include purchases for trade activities shown net of derivatives. Gigawatt hours (GWh) and $ per Megawatt hour (MWh) are shown at gross cost.*
3 *Total cost per MWh includes other electricity purchases at gross cost.*

Domestic Energy Costs

Domestic energy costs before regulatory transfers of $349 million for the three months ended December 31, 2013 were $55 million higher than in the same period in the prior year. For the nine months ended December 31, 2013, domestic energy costs before regulatory transfers of $972 million were $150 million higher than in the same period in the prior year. The increase in both periods was the result of lower water inflows in the current fiscal year and more IPPs achieving commercial operations. Water transactions related to the Non-Treaty Storage Agreement and Libby Coordination Agreement (included in Transmission charges and other expenses) resulted in reduced energy costs for three months ended December 31, 2013 as compared to the same period in the prior fiscal year and higher energy costs for the nine months ended December 31, 2013 as compared to the same period in the prior fiscal year.

In the current fiscal year, due to lower inflows, there was less hydro generation and therefore fewer surplus sales. Further, due to system constraints resulting from plant outages and colder weather, greater market electricity purchases were required in both periods. Allocation from trade was also higher in both periods due to increased net trade energy imports resulting from more purchase opportunities because of hydro conditions. In addition, water rental charges were higher in both periods as these charges are payable based on current rates, but on the prior year's and not the current year's generation. In the prior fiscal year, due to very high inflows, high reservoir levels and to manage the risk of spill, greater hydro energy was generated, resulting in a higher average price per MWh when applied to the current year's lower hydro generation. Water rental rates are indexed each calendar year based on the annual percentage change in British Columbia's consumer price index.

The Company has an agreement with Bonneville Power Administration (BPA) to operate Non-Treaty storage at Kinbasket reservoir. Under the agreement, when the Company releases water from its portion of non-treaty storage it is entitled to the value of additional energy flowing through the U.S. Federal Columbia River, as determined by the market price of energy at that time which is reflected as a reduction to cost of energy. During the three months ended December 31, 2013, the Company released more water due to strong market prices resulting in a reduction to cost of energy of $6 million as compared to the same period in the prior fiscal year. During the nine months ended December 31, 2013, the Company released less water than the same period in the prior fiscal year because there was less water in storage than the prior year due to lower water inflows and previous releases. As a result, the reduction to cost of energy for the nine months ended December 31, 2013 was only $4 million compared to $41 million in the same period in the prior fiscal year. The prior period also included $31 million for the value of net releases earned from the effective date of the agreement (September 1, 2011) to the date the contract was signed (April 22, 2012).

On September 27, 2013, the Company entered into a short-term agreement with BPA and the U.S. Army Corps of Engineers on coordination of Libby project operations. This agreement and its operations are similar to the Non-Treaty storage agreement. During the three months ended December 31, 2013, the Company's water transactions resulted in a reduction to cost of energy in the amount of $13 million.

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

Trade Energy Costs

Total trade energy costs, before regulatory account transfers, of $175 million for the three months ended December 31, 2013 were comparable with total trade energy costs of $173 million in the same period in the prior year.

Total trade energy costs, before regulatory account transfers, for the nine months ended December 31, 2013 were $591 million, an increase of $139 million compared with the same period in the prior year. Trade purchase costs increased primarily due to a 92 per cent increase in the average electricity purchase price and a 37 per cent increase in the average gas purchase price. The increase in the average electricity purchase price in the current year was primarily due to low market prices in the Pacific Northwest in the prior year due to higher water levels. The increase in the average gas purchase price reflects increases in natural gas prices in North America due to increased demand. These increases were partially offset by an 18 per cent reduction in gigawatt hours sold over the same period in the prior year primarily due to lower volumes of surplus energy purchased from BC Hydro as a result of lower water levels. Variances between actual and planned trade income (which includes trade energy costs) are deferred to the TIDA.

Water Inflows

Water inflows in the current year are significantly lower than prior year. The observed system inflow energy equivalent for the three months ended December 31, 2013 was 88 per cent of average, with inflows to Williston and Kinbasket reservoirs at 95 and 88 per cent of average, respectively. The observed system inflow energy equivalent for the three months ended December 31, 2012 was 91 per cent of average, with inflows to Williston and Kinbasket reservoirs at 77 and 104 per cent of average, respectively. The forecast system inflow energy equivalent for fiscal 2014 is 95 per cent of average, with Williston and Kinbasket reservoirs at 92 and 106 per cent of average, respectively. The system inflow energy equivalent for fiscal 2013 was 109 per cent of average, but actual inflows were higher because both Williston and Kinbasket reservoirs spilled surplus water; in addition, there was some economic spill due to negative market prices. In contrast, fiscal 2014 is experiencing below average inflows and higher market prices.

BC Hydro reservoirs have been managed such that system energy storage on December 31, 2013 was 20,100 GWh, or 200 GWh above the 10 year historic average. This was 1,300 GWh lower than the system energy storage of 21,500 GWh recorded one year earlier. The Williston and Kinbasket reservoir energy contents on December 31, 2013 were 12,700 GWh (800 GWh below the 10 year historic average) and 7,400 GWh (1000 GWh above the 10 year historic average), respectively, with Williston 1,500 GWh lower than the prior year and Kinbasket 200 GWh higher than the prior year.

PERSONNEL EXPENSES

Personnel expenses include labour, benefits and post-employment benefits. Personnel costs for the three and nine months ended December 31, 2013 of $132 million and $401 million, respectively, were $4 million and $10 million higher, respectively, than in the same periods in the prior fiscal year, primarily due to higher current service pension costs due to a decrease in the discount rate.

MATERIALS AND EXTERNAL SERVICES

Expenditures on materials and external services for the three and nine months ended December 31, 2013 of $135 million and $425 million, respectively, were $14 million and $4 million lower, respectively, than in the same periods in the prior fiscal year, primarily due to decreased services and other operational activities.

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, 2013, amortization and depreciation expense was $243 million and $734 million, respectively, $4 million and $29 million higher, respectively, than in the same periods in the prior fiscal year, primarily due to higher assets in service in the current year.

GRANTS, TAXES AND OTHER COSTS

As a Crown corporation, the Company is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts, and school tax to the Province on certain assets. Grants and taxes for the three and nine months ended December 31, 2013 of $52 million and $156 million, respectively, were comparable to the same periods 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 property, plant and equipment and overhead costs eligible for regulatory deferral that are transferred from operating costs to the IFRS Property, Plant and Equipment regulatory account. Capitalized costs for the three and nine months ended December 31, 2013 of $64 million and $183 million, respectively, were comparable to the same periods in the prior fiscal year.

FINANCE CHARGES

Finance charges after net regulatory transfers for the three months ended December 31, 2013 of $151 million were $14 million or 10 per cent higher than in the same period in the prior fiscal year. Finance charges after net regulatory transfers for the nine months ended December 31, 2013 of $450 million were $45 million or 11 per cent higher than in the same period in the prior fiscal year. The increase in both periods was primarily due to higher planned volume of debt issues and revolving borrowings, higher planned short term interest rates and higher planned lease charges. The increase was partially offset by higher planned capitalized interest during construction.

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 are comprised of the following:

(in millions)	*For the three months ended December 31* **2013**	2012	*For the nine months ended December 31* **2013**	2012
Energy Accounts				
Heritage Deferral	**$ 21**	$ (113)	**$ 51**	$ (73)
Non-Heritage Deferral	**6**	156	**42**	85
Trade Income Deferral	**8**	26	**191**	11
	35	69	**284**	23
Forecast Variance Accounts				
Finance Charges	**(18)**	(12)	**(56)**	(32)
Rate Smoothing Account	**30**	(11)	**79**	(29)
Other	**7**	(3)	**(10)**	(15)
	19	(26)	**13**	(76)
Capital-Like Accounts				
Demand Side Management (DSM)	**27**	24	**73**	80
Site C	**19**	17	**47**	55
Smart Metering and Infrastructure (SMI)	**19**	25	**57**	66
IFRS Property, Plant and Equipment	**45**	49	**135**	147
	110	115	**312**	348
Non-Cash Accounts				
Environmental Provisions	**(3)**	–	**21**	49
First Nations	**6**	5	**36**	14
Other	**2**	1	**5**	5
	5	6	**62**	68
Amortization of regulatory accounts	**(83)**	(79)	**(230)**	(227)
Interest on regulatory accounts	**15**	13	**42**	40
Net change in regulatory accounts	**$ 101**	$ 98	**$ 483**	$ 176

For the three and nine months ended December 31, 2013, net increases to the Company's regulatory accounts were $101 million and $483 million, respectively. The net asset balance in the regulatory asset and liability accounts as at December 31, 2013 was $4,917 million compared to $4,434 million as at March 31, 2013.

Combined Heritage and Non-Heritage deferral transfers were higher in the current year primarily due to higher domestic and net trade imports and fewer surplus sales due to lower water inflows. In the nine months ended December 31, 2012, higher IPP costs were offset by lower thermal generation costs and reduced energy costs from the Non-Treaty Storage Agreement, resulting in lower transfers to the deferral accounts.

Net additions to the regulatory accounts during the three and nine months ended December 31, 2013 included:

- Increases to the energy deferral accounts primarily due to the California litigation settlement, more domestic and net trade imports, as well as less surplus sales due to lower water inflows;
- Planned expenditures on DSM projects, which support energy conservation, Site C project and SMI;
- 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
- The Rate Smoothing regulatory liability account to smooth the rate increases over the three years covered by the Amended F2012-F2014 Revenue Requirements Application. The balance of the Rate Smoothing regulatory account will be fully drawn down by the end of fiscal 2014.

These net additions were partially offset by:

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

PAYMENT TO THE PROVINCE

Under a Special Directive from the Province, the Company is required to make an annual payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. No Payment has been accrued as at December 31, 2013 for fiscal 2014 as the Company's debt to equity ratio is over the 80:20 cap before any dividend accrual.

LEGAL PROCEEDINGS

CALIFORNIA 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. The settlement will become final upon the Settlement Effective Date specified in the settlement agreement, which is anticipated to occur in calendar 2014. As part of the settlement, Powerex made a net cash payment into escrow of US$273 million which translated to CDN$287 million on the transaction date and CDN$291 million as at December 31, 2013, which was recorded as restricted cash. The cash payment will remain in escrow until after occurrence of the Settlement Effective Date. The net cash payment was calculated as the difference between the agreed upon settlement amount of US$750 million and the receivables and interest owing from the California parties to Powerex of US$477 million. The net cash payment was accounted for as an adjusting subsequent event during the first quarter and an expense of CDN$214 million was recorded. The expense was calculated on the transaction date as the net cash settlement amount of CDN$287 million (US$273 million) less amounts previously accrued related to legal claims of CDN$73 million. The Province has advised BC Hydro that it intends to issue a direction or regulation by the end of fiscal 2014 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget. As a result, the loss was deferred to the TIDA.

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). The annual rate of return is equal to the pre-income tax annual rate of return allowed by the BCUC to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*. This is in accordance with Heritage Special Direction No. HC2. The allowed rate of return for fiscal 2014 is 11.84 per cent, and is higher than the prior year's allowed rate of 11.73 per cent due to a change in the FortisBC Energy Inc. tax rate.

During April 2013, the BCUC issued the Generic Cost of Capital (GCOC) decision which resulted in a reduction in the Benchmark Utility Return on Equity from 9.5 per cent to 8.75 per cent which would result in a decrease to the BC Hydro allowed rate of return (ROE) for fiscal 2014 from 11.84 per cent to 10.62 per cent. However, the Province has advised BC Hydro that it intends to issue a direction or regulation by the end of fiscal 2014 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget. Had the impact of the GCOC decision been reflected in the nine months ended December 31, 2013, the Non-Heritage Deferral Account, and consequently net income, would have been approximately $39 million lower than recorded.

BC HYDRO 10-YEAR PLAN

On November 26, 2013, the Government announced a 10-year plan for BC Hydro. Under the 10-year plan the Government will be issuing a Directive to the BCUC setting BC Hydro's rate increase at 9 per cent for fiscal 2015 and 6 per cent for fiscal 2016. The Directive is expected to be issued in late February 2014. For fiscal 2017, fiscal 2018 and fiscal 2019, BC Hydro's rate increases will be set by the BCUC within capped amounts of 4 per cent, 3.5 per cent and 3.0 per cent respectively. The BCUC will also set the rates for the final five years of the plan. In addition, the Deferral Account Rate Rider will remain at 5 per cent.

INDUSTRIAL ELECTRICITY POLICY REVIEW

An Industrial Electricity Policy Review was launched in late January 2013 when a three person panel was appointed by Government. The main issue reviewed was with regard to changes to transmission voltage rates, or the regulatory framework within those rates are established, and which could be made to advance the objectives of electricity conservation, economic development and take into account the current environmental policy. The Government subsequently supplemented the Terms of Reference to include a review of Industrial Time-of-Use rates, utility interconnection and retail access policies in other relevant jurisdictions. The Industrial Electricity Policy Review Final Report was issued on November 26, 2013 and contains 17 recommendations, six of which are to be carried out by BC Hydro. In spring 2014, BC Hydro expects to begin development of a rate design review process to act on the report's recommendations.

AVAILABLE TRANSFER CAPACITY (ATC) RULE

On December 5, 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 because of the harm it would cause to the Company and its ratepayers. The AUC issued its decision on February 1, 2013 approving the rule as filed. 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 a decision is expected before the end of fiscal 2014.

NEW POWER PURCHASE AGREEMENT WITH FORTISBC

In May 2013, BC Hydro filed an application with the BCUC for approval of a new 20-year Power Purchase Agreement (PPA) with FortisBC. BC Hydro's current PPA with FortisBC has been in place since 1993 and expired on September 30, 2013. The BCUC has extended the term of the PPA beyond September 30, 2013, until such time as they issue their decision on the application. BC Hydro and FortisBC have been in negotiations for a new agreement for several years. The BCUC conducted a written process to review the application and on December 13, 2013 requested additional submissions from BC Hydro, FortisBC and interveners in regards to the provisions of the PPA designed to protect BC Hydro against FortisBC and its self-generating customers who may engage in arbitrage opportunities. A decision is now expected by spring 2014.

APPLICATION FOR APPROVAL OF CHARGES RELATED TO METER CHOICES PROGRAM

On October 7, 2013, BC Hydro filed an application with the BCUC for approval of new charges related to its Meter Choices Program, pursuant to Government Direction No. 4 issued on September 25, 2013. The application requests approval of changes to BC Hydro's Electric Tariff that will allow BC Hydro to charge customers who choose to retain a legacy meter, or choose the radio-off option for their smart meters, a fee designed to recover the additional costs of meter options other than a smart meter. The application also requests approval of a regulatory account to capture the costs to BC Hydro of offering the meter choices program to its customers and approval to charge a failed installation charge to those customers who have a failed meter installation. The BCUC has established a written process with two rounds of information requests to review the application. BC Hydro responded to the first round on November 22, 2013 and responded to the second round on January 17, 2014.

RESIDENTIAL INCLINING BLOCK (RIB) RE-PRICING

In November 2013, BC Hydro filed an application seeking approval of new pricing principles for its RIB rate for fiscal 2015 and fiscal 2016 as the current pricing principles expire at the end of fiscal 2014. If approved, the new pricing principles would see rate increases applied equally to each of the basic charge, Step 1 and Step 2 energy prices. BC Hydro has responded to one round of information requests. BC Hydro filed a submission with regard to the further review process for the application and requested that a streamlined review process be undertaken prior to the end of January 2014 if there was no need for a second round of information requests. BC Hydro has requested that a decision be issued prior to the end of fiscal 2014.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the nine months ended December 31, 2013 was $302 million, compared with cash flow provided by operating activities of $533 million in the prior fiscal year. The decrease was primarily due to a decrease in cash flows from net income before regulatory transfers due to higher energy costs, partially offset by higher revenues. A decrease in working capital was mainly due to restricted cash, partially offset by the timing of other working capital items.

The long-term debt balance net of sinking funds at December 31, 2013 was $15,658 million, compared with $14,022 million at March 31, 2013. The increase was mainly as a result of an increase in revolving borrowings of $1,312 million, an increase in net long-term bond issues totaling $1,011 million ($1,150 million par value), and net foreign exchange revaluation losses of $45 million. These increases were partially offset by long-term bond redemptions totaling $706 million par value, net gains on economic hedging activities of $14 million, amortization of premiums of $8 million and sinking fund income of $4 million. Long-term debt increased primarily to fund capital expenditures.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

(in millions)	*For the three months ended December 31* 2013	2012	*For the nine months ended December 31* 2013	2012
Distribution system improvements and expansion	$ 91	$ 75	$ 240	$ 224
Generation replacements and expansion	118	108	329	312
Transmission lines and substations replacements & expansion	261	243	723	598
Smart Metering and Infrastructure program	22	46	66	220
General, including technology, vehicles and building improvements	61	48	152	119
Total Property, Plant and Equipment Expenditures	$ 553	$ 520	$ 1,510	$ 1,473

Total property, plant and equipment expenditures presented in this table are different from the expenditures in the Consolidated Interim Statement of Cash Flows due to effect of accruals related to these expenditures.

Distribution capital expenditures for the three and nine months ended December 31, 2013 were $91 million and $240 million, respectively, which includes expenditures on customer driven work, end of life asset replacement, system expansion and improvement projects.

Generation capital expenditures for the three and nine months ended December 31, 2013 were $118 million and $329 million, respectively, which includes expenditures for Mica Unit 5 & 6 Installation, Ruskin Dam and Powerhouse Upgrade, G.M. Shrum Units 1 to 5 Turbine Rehabilitation, Hugh Keenleyside Spillway Gate Reliability Upgrade and John Hart Replacement projects.

Transmission lines and substations capital expenditures for the three and nine months ended December 31, 2013 were $261 million and $723 million, respectively, which includes expenditures on the Northwest Transmission Line, Vancouver City Central Transmission, Interior to Lower Mainland transmission line, Seymour Arms Series Capacitor Station, Dawson Creek/Chetwynd Area Transmission, Iskut Extension and Gibraltar Mines Phase III projects.

SMI capital expenditures for the three and nine months ended December 31, 2013 were $22 million and $66 million, respectively, $24 million and $154 million lower, respectively, than in the same periods in the prior fiscal year as the SMI program was in full implementation in the second quarter of fiscal 2013, including the mass deployment of meters which is now complete. Currently, activities are focused around network equipment purchases and remaining meter installations.

General capital expenditures for the three and nine months ended December 31, 2013 were $61 million and $152 million, respectively, which primarily included expenditures on various technology projects and properties programs.

RISK MANAGEMENT

BC Hydro is exposed to numerous risks, which can be broadly classified as either "Operating" or "Strategic" in nature. Operating risks arise from the construction, ownership, operation and decommissioning of the Company's assets. The consequences of operating risks include safety, environmental, financial, reliability and reputational impacts and can range in scale from minor to catastrophic. Significant strategic risks include both long term and short term load/resource balance, exposure to commodity and financial market prices, stakeholder relationships and access to adequate funding. The potential consequences of these risks are similar to those of operating risks and can vary from minor to significant.

The Company strives to manage all the risks it faces on a cost effective basis, taking into account the potential reward to be gained in return for acceptance of the risk. The Company also takes into account the provisions of externally recognized standards appropriate to the risk being managed.

The Board of Directors is accountable for all risks incurred by the Company and its subsidiaries. Authority for risk management is delegated to the Chief Executive Officer. The Chief Risk Officer is charged with the development of the enterprise risk management framework across all of the Company, which provides the basis for consistent application of risk management practices. The Board of Directors and management regularly review and discuss the risk profile of the organization and consider the nature and amount of risk incurred in the pursuit of the organization's objectives.

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, 2013.

LOAD/ENERGY RESOURCE BALANCE

Variations in system inflows, market prices, and domestic load can significantly influence cost of energy. The current system inflow energy for fiscal 2014 is forecast to be five per cent below average, compared to the system inflow energy for fiscal 2013 which was nine per cent above average (with unusually high water conditions and some flooding impacts during fiscal 2013). The fiscal 2014 forecast of net market purchases is 1,344 GWh, which is significantly different than fiscal 2013 net market sales of approximately 6,500 GWh, due primarily to the differences in runoff conditions between fiscal 2013 and fiscal 2014.

Several factors constrain the Company's ability to use its stored system energy to meet load throughout the year. These factors include generating unit outages at major plants (forced outages and capital projects) as well as water management constraints which limit generation at the major plants during some periods. Even when the system has annual net energy sales, some electricity purchases are likely required during constrained periods of the year (e.g. late fall, winter, early spring), while electricity sales may be unavoidable during other periods to minimize spill from system reservoirs. The value of these purchases and sales is subject to market price risk.

Electricity demand is generally increasing as B.C.'s population increases. However, this demand can be variable for large industrial customers due to variability in export markets and world commodity prices, and the potential for major new loads such as Liquefied Natural Gas (LNG). The Company has been and continues to work closely with the Government and LNG project proponents on plans to meet these potentially very large demands. The Company regularly models the projected supply-demand balance of the system over the short term to plan optimum system operations and over the medium term to cost-effectively meet demand.

FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro filed a revised Service Plan in June 2013 that forecasts net income for fiscal 2014 at $545 million.

BC Hydro prepared an updated forecast in January 2014 consistent with the 10-year plan announced by the Government in November 2013. This forecast is incorporated into the February 2014 Service Plan and forecasts a net income of $545 million for fiscal 2014 and $582 million for fiscal 2015. 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, interest rates and foreign exchange rates. Many of these variances are transferred to regulatory accounts to minimize fluctuations in rates. The forecast for fiscal 2015 assumes average water inflows (100 per cent of average), domestic sales load of 56,886 GWh, average market energy prices of US $31.85/MWh, short-term interest rates of 1.28 per cent and a U.S. dollar exchange rate of US$0.9547.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2013**	2012	**2013**	2012
Revenues				
Domestic	**$ 1,165**	$ 1,085	**$ 3,082**	$ 2,866
Trade	**206**	200	**766**	605
	1,371	1,285	**3,848**	3,471
Expenses				
Operating Expenses (Note 4)	**993**	936	**3,025**	2,726
Finance Charges (Note 5)	**151**	137	**450**	405
Net Income	**227**	212	**373**	340
OTHER COMPREHENSIVE INCOME				
Items Reclassified Subsequently to Net Income				
Effective portion of changes in fair value of derivatives designated as cash flow hedges	**8**	8	**18**	(10)
Reclassification to income on derivatives designated as cash flow hedges	**(27)**	(8)	**(37)**	6
Foreign currency translation gains (losses)	**8**	2	**9**	(1)
Other Comprehensive Income (Loss)	**(11)**	2	**(10)**	(5)
Total **Comprehensive Income**	**$ 216**	$ 214	**$ 363**	$ 335

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* **2013**	*As at March 31* 2013
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 220**	$ 60
Restricted cash (Note 15)	**291**	–
Accounts receivable and accrued revenue	**677**	721
Inventories (Note 7)	**161**	173
Prepaid expenses	**102**	201
Current portion of derivative financial instrument assets (Note 14)	**103**	83
	1,554	1,238
Non-Current Assets		
Property, plant and equipment (Note 8)	**18,177**	17,226
Intangible assets (Note 8)	**505**	438
Regulatory assets (Note 9)	**5,173**	4,741
Sinking funds	**122**	112
Derivative financial instrument assets (Note 14)	**32**	27
	24,009	22,544
	$ 25,563	$ 23,782
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Notes 11 and 13)	**$ 1,452**	$ 1,544
Current portion of long-term debt (Note 10)	**4,210**	3,288
Current portion of derivative financial instrument liabilities (Note 14)	**54**	172
	5,716	5,004
Non-Current Liabilities		
Long-term debt (Note 10)	**11,570**	10,846
Regulatory liabilities (Note 9)	**256**	307
Derivative financial instrument liabilities, long-term (Note 14)	**73**	94
Contributions in aid of construction	**1,272**	1,196
Post employment benefits	**1,407**	1,396
Other long-term liabilities (Note 13)	**1,406**	1,439
	15,984	15,278
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**3,742**	3,369
Accumulated other comprehensive income	**61**	71
	3,863	3,500
	$ 25,563	$ 23,782

Commitments and Contingencies (Notes 8 and 15)

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

Approved on Behalf of the Board:

Stephen Bellringer
Chairman

Tracey L. McVicar
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, 2012	$ 21	$ 63	$ 84	$ 60	$ 3,075	$ 3,219
Payment to the Province	-	-	-	-	(68)	(68)
Comprehensive Income (Loss)	(1)	(4)	(5)	-	340	335
Balance, December 31, 2012	$ 20	$ 59	$ 79	$ 60	$ 3,347	$ 3,486
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

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* 2013	2012
Operating Activities		
Net income	**$ 373**	$ 340
Regulatory account transfers	**(713)**	(403)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 9)	**230**	227
Amortization and depreciation expense	**480**	461
Unrealized gains on mark-to-market	**(73)**	(25)
Interest accrual	**487**	473
Other items	**56**	6
	840	1,079
Changes in:		
Restricted cash	**(291)**	–
Accounts receivable and accrued revenue	**73**	(72)
Prepaid expenses	**99**	69
Inventories	**16**	(17)
Accounts payable, accrued liabilities and other long-term liabilities	**28**	(110)
Contributions in aid of construction	**102**	112
	27	(18)
Interest paid	**(565)**	(528)
Cash provided by operating activities	**302**	533
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(1,445)**	(1,399)
Cash used in investing activities	**(1,445)**	(1,399)
Financing Activities		
Long-term debt:		
Issued	**1,011**	1,367
Retired	**(706)**	(200)
Receipt of revolving borrowings	**6,533**	4,524
Repayment of revolving borrowings	**(5,224)**	(4,508)
Payment to the Province (Note 11)	**(215)**	(230)
Settlement of derivative instruments	**(84)**	–
Other items	**(12)**	(13)
Cash provided by financing activities	**1,303**	940
Increase in cash and cash equivalents	**160**	74
Cash and cash equivalents, beginning of period	**60**	12
Cash and cash equivalents, end of period	**$ 220**	$ 86

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 including Powerex Corp., Powertech Labs Inc., and Columbia Hydro Constructors Ltd., (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) except that BC Hydro is to apply 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 net 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 2013 Annual Report except as described in Note 3. These interim consolidated financial statements should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2013 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 30, 2014.

NOTE 3: CHANGE IN ACCOUNTING POLICIES

POST EMPLOYMENT BENEFITS

Effective April 1, 2013, the Company adopted, as required, IAS 19, *Employee Benefits*, as amended in June 2011.

The amended IAS 19 replaced interest costs on the defined benefit obligation and the expected return on plan assets with a net interest cost based on the net defined benefit asset or liability. The net interest for the period is determined by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability at the beginning of the annual period, taking into account any changes in the net defined benefit asset or liability during the period as a result of current service costs, contributions and benefit payments. Previously, the Company determined expected return on plan assets based on their long term rate of expected return.

The Company applied the amended standard retrospectively to the prior periods presented. The impact of the adoption of the amended IAS 19 on the measurement of employee benefit costs was mitigated by the application of regulatory accounting in the current and prior periods presented.

FAIR VALUE MEASUREMENT

Effective April 1, 2013, the Company adopted, as required, IFRS 13, *Fair Value Measurement* (IFRS 13) and applied the standard prospectively as required by the transitional provisions. The standard provides a consistent definition of fair value and introduces consistent requirements for disclosures related to fair value measurement. There has been no significant measurement adjustments of items recorded at fair value as a result of the adoption of IFRS 13 in the current period. Some disclosures are specifically required in interim financial statements for financial instruments as a result of consequential amendments to IAS 34 *Interim Financial Reporting*. The additional disclosures are included in Note 14.

Other standards that have been adopted effective April 1, 2013 that have little or no impact on the consolidated financial statements include:

- IFRS 10, *Consolidated Financial Statements*
- IFRS 11, *Joint Arrangements*
- IFRS 12, *Disclosure of Interests in Other Entities*
- Amendments to IAS 1, *Presentation of Financial Statements*
- IAS 28, *Investments in Associates and Joint Ventures*
- IFRS 7, *Offsetting Financial Assets and Liabilities*

NOTE 4: OPERATING EXPENSES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2013**	2012	**2013**	2012
Electricity and gas purchases	**$ 340**	$ 293	**$ 1,080**	$ 861
Water rentals	**104**	100	**271**	256
Transmission charges	**51**	46	**141**	128
Personnel expenses	**132**	128	**401**	391
Materials and external services	**135**	149	**425**	429
Amortization and depreciation (Note 6)	**243**	239	**734**	705
Grants, taxes and other costs	**52**	47	**156**	149
Capitalized costs	**(64)**	(66)	**(183)**	(193)
Total	**$ 993**	$ 936	**$ 3,025**	$ 2,726

NOTE 5: FINANCE CHARGES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2013**	2012	**2013**	2012
Interest on long-term debt	**$ 184**	$ 165	**$ 549**	$ 485
Interest on finance lease liabilities	**11**	7	**34**	20
Net interest expense on net defined benefit liability	**3**	3	**10**	10
Less: capitalized interest	**(26)**	(18)	**(79)**	(55)
Total finance costs	**172**	157	**514**	460
Other recoveries	**(21)**	(20)	**(64)**	(55)
Total	**$ 151**	$ 137	**$ 450**	$ 405

NOTE 6: AMORTIZATION AND DEPRECIATION

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2013**	2012	**2013**	2012
Depreciation of property, plant and equipment	**$ 137**	$ 139	**$ 434**	$ 418
Amortization of intangible assets	**16**	15	**46**	43
Amortization of regulatory accounts and other	**90**	85	**254**	244
Total	**$ 243**	$ 239	**$ 734**	$ 705

NOTE 7: INVENTORIES

(in millions)	***As at December 31* 2013**	*As at March 31* 2013
Materials and supplies	**$ 112**	$ 108
Natural gas trading inventories	**49**	65
Total	**$ 161**	$ 173

During the three month and nine month periods ended December 31, 2013, an impairment recovery of $2 million and an impairment of $nil, respectively, (three month and nine month periods ended December 31, 2012 – impairment of $1 million and impairment recovery of $15 million, respectively) was charged to cost of energy to adjust the recorded value of natural gas inventories as a result of fluctuations in market prices. As at December 31, 2013, $22 million (December 31, 2012 - $46 million) of the value of natural gas inventories was valued at net realizable value.

NOTE 8: PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Property, plant and equipment and intangible asset expenditures for the three and nine month periods ended December 31, 2013 were $553 million and $1,510 million, respectively (2012 - $520 million and $1,473 million, respectively).

As of December 31, 2013, the Company has contractual commitments to spend $776 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 net income unless the Company sought recovery through rates in the year which they are incurred. For the three and nine months ended December 31, 2013, the impact of regulatory accounting has resulted in an increase to comprehensive income of $101 million and $483 million, respectively (2012 - $98 million and $176 million increase, respectively). For each regulatory account, the amount reflected in the Net Change column in the following regulatory tables represents the impact on comprehensive income for the applicable year, unless otherwise recovered through rates. Under rate regulated accounting, a net decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to comprehensive income.

(in millions)	*April 1 2013*	*Addition (Reduction)*	*Amortization*	*Net Change*	*December 31 2013*
Regulatory Assets					
Heritage Deferral Account	$ 70	$ 53	$ (13)	$ 40	$ 110
Non-Heritage Deferral Account	467	56	(85)	(29)	438
Trade Income Deferral Account	190	200	(35)	165	355
Demand-Side Management Programs	733	73	(47)	26	759
First Nation Negotiations,					
Litigation & Settlement Costs	553	36	(4)	32	585
Non-Current Pension Cost	544	(12)	(13)	(25)	519
Site C	258	56	–	56	314
CIA Amortization Variance	75	4	–	4	79
Environmental Provisions	367	22	(5)	17	384
Smart Metering and Infrastructure	192	63	–	63	255
Finance Charges	1	(1)	–	(1)	–
IFRS Pension & Other					
Post-Employment Benefits	723	–	(26)	(26)	697
IFRS Property, Plant and Equipment	447	134	(7)	127	574
Other Regulatory Accounts	121	2	(19)	(17)	104
Total Regulatory Assets	4,741	686	(254)	432	5,173
Regulatory Liabilities					
Future Removal and Site Restoration Costs	88	–	(24)	(24)	64
Rate Smoothing	111	(79)	–	(79)	32
Foreign Exchange Gains and Losses	100	(6)	–	(6)	94
Finance Charges	–	55	–	55	55
Other Regulatory Accounts	8	3	–	3	11
Total Regulatory Liabilities	307	(27)	(24)	(51)	256
Net Regulatory Asset	$ 4,434	$ 713	$ (230)	$ 483	$ 4,917

During April 2013, the BCUC issued the Generic Cost of Capital (GCOC) decision which resulted in a reduction in the Benchmark Utility Return on Equity from 9.5 per cent to 8.75 per cent which would result in a decrease to the BC Hydro allowed rate of return (ROE) for fiscal 2014 from 11.84 per cent to 10.62 per cent. The Province has advised BC Hydro that it intends to issue a direction or regulation by the end of fiscal 2014 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget. Had the impact of the GCOC decision been reflected in the nine months ended December 31, 2013, the Non-Heritage Deferral Account, and consequently net income, would have been approximately $39 million lower than recorded.

On October 4, 2013, the Company's subsidiary Powerex received approval by the Federal Energy Regulatory Commission (FERC) for a settlement agreement with parties involved in the various ongoing legal claims in California to resolve all outstanding claims and litigation filed against it arising from events and transactions in the California power market during the 2000 and 2001 period (see Note 15). This was accounted for as an adjusting subsequent event in the first quarter which resulted in an expense of $214 million. The Province has advised BC Hydro that it intends to issue a direction or regulation by the end of fiscal 2014 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget. As a result, the loss was fully deferred to the Trade Income Deferral Account (TIDA).

OTHER REGULATORY ACCOUNTS

Other regulatory asset and liability accounts with individual balances less than $40 million include the following: Arrow Water Systems Divestiture, Capital Project Investigation Costs, Home Purchase Option Program, Return on Equity (ROE) Adjustment, Waneta Rate Smoothing, Asbestos Remediation, Amortization of Capital Additions, and Storm Damage.

NOTE 10: 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, 2013, the Company did not issue any bonds (2012 - $300 million, a weighted average effective interest rate of 3.30 per cent and a weighted average term to maturity of 27 years). For the nine month period ended December 31, 2013, the Company issued bonds with net proceeds of $1,011 million and par value of $1,150 million (2012 – net proceeds of $1,367 million and par value of $1,233 million), a weighted average effective interest rate of 3.92 per cent (2012 – 3.31 per cent) and a weighted average term to maturity of 30 years (2012 – 26 years).

NOTE 11: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining the Company's equity for regulatory purposes, as well as the annual Payment to the Province. 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 (loss) and contributed surplus.

During the nine months ended December 31, 2013, there were no changes in the approach to capital management.

The debt to equity ratio at December 31, 2013 and March 31, 2013 was as follows:

(in millions)	*As at December 31* **2013**	*As at March 31* 2013
Total debt, net of sinking funds	**$ 15,658**	$ 14,022
Less: Cash and cash equivalents	**(220)**	(60)
Net Debt	**$ 15,438**	$ 13,962
Retained earnings	**$ 3,742**	$ 3,369
Contributed surplus	**60**	60
Accumulated other comprehensive income	**61**	71
Total Equity	**$ 3,863**	$ 3,500
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. No Payment has been accrued as at December 31, 2013 (March 31, 2013 - $215 million, included in accounts payable and accrued liabilities) as the Company's debt to equity ratio is over the 80:20 cap before any dividend accrual.

NOTE 12: POST EMPLOYMENT BENEFITS

The expense recognized in the statement of comprehensive income for the Company's benefit plans prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions for the three and nine months ended December 31, 2013 was $27 million and $55 million, respectively (2012 - $24 million and $48 million, respectively).

Contributions to the registered defined benefit pension plans for the three and nine months ended December 31, 2013 were $16 million and $31 million, respectively (2012 - $12 million and $24 million, respectively).

NOTE 13: OTHER LONG-TERM LIABILITIES

(in millions)	*December 31* **2013**	*March 31* 2013
Provisions		
Environmental liabilities	**$ 335**	$ 340
Decommissioning obligations	**49**	52
Other	**308**	43
Total Provisions	**692**	435
First Nations liabilities	**412**	387
Finance lease obligations	**280**	292
Deferred revenue - Skagit River Agreement	**436**	423
	1,820	1,537
Less: Current portion, included in accounts payable and accrued liabilities	**(414)**	(98)
Total	**$ 1,406**	$ 1,439

Other provisions include $291 million relating to the California Settlement described in Note 15.

NOTE 14: FINANCIAL INSTRUMENTS

Finance charge income and expenses for financial instruments disclosed in the following note are prior to the application of regulatory accounting for the three and nine months ended December 31, 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, 2013:

	As at December 31, 2013		Interest Income (Expense) recognized in Finance Charges	
(in millions)	Carrying Value	Fair Value	*For the three months ended December 31*	*For the nine months ended December 31*
Financial Assets and Liabilities at Fair Value Through Profit or Loss:				
Short-term investments	$ 143	$ 143	$ –	$ 1
Designated long-term debt	–	–	–	(13)
Loans and Receivables:				
Accounts receivable and accrued revenue	677	677	–	–
Restricted cash	291	291	–	–
Cash	77	77	–	–
Held to Maturity:				
Sinking funds – US	122	130	1	4
Other Financial Liabilities:				
Accounts payable and accrued liabilities	(1,452)	(1,452)	–	–
Revolving borrowings - CAD	(3,182)	(3,182)	(7)	(16)
Revolving borrowings - US	(703)	(703)	–	(1)
Long-term debt (including current portion due in one year)	(11,895)	(12,997)	(154)	(448)
First Nations liability (long-term portion only)	(380)	(629)	(5)	(16)
Finance Lease Obligation (long-term portion only)	(263)	(263)	(6)	(18)

For non-derivative financial assets and liabilities classified as financial assets and liabilities at fair value through profit or loss, $nil and a gain of $12 million, respectively, have been recognized in net income for the three and nine months ended December 31, 2013, respectively, 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:

	As at December 31, 2013	
(in millions)	Carrying Value	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)	$ (54)	$ (54)
Non-Designated Derivative Instruments:		
Foreign currency contracts	14	14
Commodity derivatives	48	48
	62	62
Total	$ 8	$ 8

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

(in millions)	*As at December 31, 2013*
Current portion of derivative financial instrument assets	$ 103
Current portion of derivative financial instrument liabilities	(54)
Derivative financial instrument assets, long-term	32
Derivative financial instrument liabilities, long-term	(73)
Total	$ 8

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

For the three and nine months ended December 31, 2013, a gain of $35 million and a gain of $37 million, respectively, were recognized in finance charges with respect to foreign currency contracts for U.S. short-term borrowings. These economic hedges offset $45 million of foreign exchange revaluation losses recorded with respect to U.S. short-term borrowings for the nine months ended December 31, 2013. Net gains of $27 million and $45 million were recorded in trade revenue for the three and nine months ended December 31, 2013, respectively, with respect to commodity derivatives.

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, 2013:

(in millions)	Level 1	Level 2	Level 3	Total
Short-term investments	$ 143	$ –	$ –	$ 143
Derivatives designated as hedges	–	12	–	12
Derivatives not designated as hedges	24	47	52	123
Total financial assets carried at fair value	$ 167	$ 59	$ 52	$ 278
Derivatives designated as hedges	$ –	$ (66)	$ –	$ (66)
Derivatives not designated as hedges	(32)	(27)	(2)	(61)
Total financial liabilities carried at fair value	$ (32)	$ (93)	$ (2)	$ (127)

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.

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, 2013:

(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.

Net gains of $7 million and $28 million were recognized in net income during the three and nine months ended December 31, 2013, respectively, related to Level 3 financial instruments held at December 31, 2013. The net gains are 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.

NOTE 15: COMMITMENTS AND CONTINGENCIES

CALIFORNIA 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. The settlement will become final upon the Settlement Effective Date specified in the settlement agreement, which is anticipated to occur in calendar 2014. As part of the settlement, Powerex made a net cash payment into escrow of US$273 million which translated to CDN$287 million on the transaction date and CDN$291 million as at December 31, 2013, which was recorded as restricted cash. The cash payment will remain in escrow until after occurrence of the Settlement Effective Date. The net cash payment was calculated as the difference between the agreed upon settlement amount of US$750 million and the receivables and interest owing from the California parties to Powerex of US$477 million. The net cash payment was accounted for as an adjusting subsequent event during the first quarter and an expense of CDN$214 million was recorded. The expense was calculated on the transaction date as the net cash settlement amount of CDN$287 million (US$273 million) less amounts previously accrued related to legal claims of CDN$73 million. The Province has advised BC Hydro that it intends to issue a direction or regulation by the end of fiscal 2014 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget. As a result, the loss was deferred to the TIDA.

NOTE 16: SEASONALITY OF OPERATING RESULTS

Due to the seasonal nature of the Company's operations, the condensed consolidated interim statements 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.