BC HYDRO THIRD QUARTER REPORT FISCAL 2013

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, 2012 (fiscal 2013) and should be read in conjunction with the MD&A presented in the 2012 Annual Report, the 2012 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, 2012.

Effective April 1, 2012, the Company changed its financial reporting framework from Canadian generally accepted accounting principles (CGAAP) to 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"), as prescribed by the Province of British Columbia ("the Province"). All financial information is expressed in Canadian dollars unless otherwise specified, and prior year amounts have been restated to conform to the Prescribed Standards. For more information on the Company's transition to the Prescribed Standards, please see the "Explanation of Transition to the Prescribed Standards" section of this MD&A and Notes 2 and 16 of the Unaudited Condensed Consolidated Interim Financial Statements for the three and nine months ended December 31, 2012.

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 after regulatory transfers for the three and nine months ended December 31, 2012 was $212 million and $340 million, respectively, $2 million and $29 million lower, respectively, than the same periods in the prior fiscal year. The decrease for the nine months was primarily due to higher amortization and depreciation expense due to higher assets in service and higher regulatory account amortization, increased current service pension costs due to changes in the discount rate and fewer costs transferred to capital. This was partially offset by higher domestic revenues due to higher average customer rates and surplus energy sales.

- Usable system inflows for fiscal 2013 are forecast to be 109 per cent of average, comparable to 108 per cent of average in fiscal 2012. At December 31, 2012, the combined system storage in the Company's reservoirs was 112 per cent of average compared to 113 per cent of average at December 31, 2011. As a result of the high inflows, the Company sold a significant volume of surplus energy in the nine months ended December 31, 2012, an increase of over 4,000 GWh as compared to surplus energy sales in the first nine months of fiscal 2012. The high inflows also resulted in both the Williston and Kinbasket reservoirs spilling substantial volumes of surplus water in the summer of 2012, with the result that usable system inflows for fiscal 2013 will be significantly less than total system inflows.

- Capital expenditures for the three and nine months ended December 31, 2012 were $520 million and $1,473 million, respectively. Capital expenditures for the nine months ended December 31, 2012 were $204 million lower than the plan amount of $1,677 million. Despite the lower than plan expenditures mainly due to delays on several projects, BC Hydro continues to invest significantly to refurbish its ageing infrastructure and build new assets for future growth, including Mica Units 5 & 6 Project, Northwest Transmission Line Project, G.M. Shrum Units 1 to 5 Turbine Rehabilitation, Ruskin Dam and Powerhouse Upgrade, Smart Metering and Infrastructure Program (SMI), Interior Mainland Project, and Vancouver City Central Project. Permanent cost savings were realized on the Columbia Valley Transmission Project due to lower material and equipment costs.

	For the three months ended December 31			*For the nine months ended December 31*		
(in millions)	**2012**	2011	Change	**2012**	2011	Change
Net Income	**$ 212**	$ 214	$ (2)	**$ 340**	$ 369	$ (29)
Number of Domestic Customers	**N/A**	N/A	N/A	**1,887,281**	1,867,437	19,844
GWh Sold (Domestic)	**13,957**	13,817	140	**42,266**	37,785	4,481
Total Reservoir Storage (GWh)	**N/A**	N/A	N/A	**24,608**	23,558	1,050

(in millions)	*As at December 31, 2012*	*As at March 31, 2012*	Change
Total Assets	**$ 23,101**	$ 21,900	$ 1,201
Retained Earnings	**$ 3,347**	$ 3,075	$ 272
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 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, 2012, net transfers to regulatory accounts of $98 million and $176 million, respectively, were primarily due to transfers to the energy deferral accounts for higher than forecast domestic energy costs, lower domestic load and lower trade income, partially offset by favourable variances between forecast and actual other energy sales. In addition, net transfers to regulatory accounts were due to expenditures on demand-side management programs (DSM), Site C and SMI, the phasing in of the rate impact of the reduction in the amount of overhead eligible for capitalization under IFRS as compared to CGAAP and, for the nine months, increases in the provisions for asbestos and polychlorinated biphenyls (PCBs). These increases were partially offset by transfers from the finance charges regulatory account for lower than forecast finance charges.

Net income after regulatory transfers for the three and nine months ended December 31, 2012 was $212 million and $340 million, respectively, $2 million and $29 million lower, respectively, than the same periods in the prior fiscal year. The decrease for the nine months was primarily due higher amortization and depreciation expense due to higher assets in service and higher regulatory account amortization, higher personnel expenditures, losses on asset disposals and retirements and lower capitalized costs. This was partially offset by higher domestic revenues due to higher average customer rates and surplus energy sales.

REVENUES

Total revenue for the three months ended December 31, 2012 was $1,285 million, an increase of $94 million or eight per cent compared to the same period in the prior fiscal year primarily due to higher domestic revenues resulting primarily from an increase in average customer rates and increased other energy sales. Total revenue for the nine months ended December 31, 2012 was $3,471 million, a decrease of $19 million or one per cent compared to the same period in the prior fiscal year. The decrease was primarily due to lower trade revenues resulting from lower trade electricity and natural gas prices, partially offset by higher domestic revenues resulting from higher average customer rates and other energy sales.

	(in millions)		(gigawatt hours)	
For the three months ended December 31	**2012**	2011	**2012**	2011
Domestic				
Residential	**$ 458**	$ 449	**5,018**	5,155
Light industrial and commercial	**364**	345	**4,640**	4,635
Large industrial	**159**	152	**3,407**	3,483
Other energy sales	**66**	59	**892**	544
Total Domestic Revenue Before Regulatory Transfer	**1,047**	1,005	**13,957**	13,817
Rate smoothing and load variance regulatory transfer	**38**	(12)	**-**	-
Total Domestic	**$ 1,085**	$ 993	**13,957**	13,817
Trade				
Electricity – Gross	**$ 200**	$ 226	**5,599**	5,191
Less: forward electricity purchases[1]	**(46)**	(79)	**-**	-
Electricity – Net	**154**	147	**-**	-
Gas – Gross	**253**	279	**7,267**	7,202
Less: forward gas purchases[1]	**(207)**	(228)	**-**	-
Gas – Net	**46**	51	**-**	-
Total Trade[2]	**$ 200**	$ 198	**12,866**	12,393
Total Revenues	**$ 1,285**	$ 1,191	**26,823**	26,210

	(in millions)		(gigawatt hours)	
For the nine months ended December 31	**2012**	2011	**2012**	2011
Domestic				
Residential	**$ 1,093**	$ 1,081	**12,124**	12,701
Light industrial and commercial	**1,058**	983	**13,562**	13,306
Large industrial	**472**	430	**10,168**	10,040
Other energy sales	**236**	172	**6,412**	1,738
Total Domestic Revenue Before Regulatory Transfer	**2,859**	2,666	**42,266**	37,785
Rate smoothing and load variance regulatory transfer	**7**	(19)	**-**	-
Total Domestic	**$ 2,866**	$ 2,647	**42,266**	37,785
Trade				
Electricity – Gross	**$ 675**	$ 838	**24,924**	21,858
Less: forward electricity purchases[1]	**(165)**	(225)	**-**	-
Electricity – Net	**510**	613	**-**	-
Gas – Gross	**539**	805	**20,589**	20,309
Less: forward gas purchases[1]	**(444)**	(575)	**-**	-
Gas – Net	**95**	230	**-**	-
Total Trade[2]	**$ 605**	$ 843	**45,513**	42,167
Total Revenues	**$ 3,471**	$ 3,490	**87,779**	79,952

[1]Forward purchases include derivatives which are deducted from gross sales in accordance with the Prescribed Standards.
[2]Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer.

DOMESTIC REVENUES

Total domestic revenues after regulatory transfers for the three months ended December 31, 2012 were $1,085 million, a $92 million increase over the comparable period in the prior fiscal year. Total domestic revenues after regulatory transfers for the nine months ended December 31, 2012 were $2,866 million, an increase of $219 million over the comparable period in the prior fiscal year.

Domestic revenues after regulatory account transfers were higher in the three months ended December 31, 2012 due mainly to higher average customer rates and higher other energy sales. Domestic revenues after regulatory account transfers were higher in the nine months ended December 31, 2012 due mainly to higher average customer rates, increased consumption by light industrial and commercial and large industrial customer classes, and higher other energy sales. Other energy sales increased due to significantly higher volumes of surplus energy sold into the market as compared to the same period in the prior fiscal year due to high water inflows, but at significantly lower market prices.

Average customer rates were higher in fiscal 2013, reflecting an average rate increase of 3.91 per cent approved by BCUC for fiscal 2013 and a Deferral Account Rate Rider (DARR) of 5 per cent for fiscal 2013 compared to a DARR of 2.5 per cent in effect in fiscal 2012.

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.

Gross trade revenue for the three months ended December 31, 2012 was $453 million, a decrease of $52 million compared with the same period in the prior year due to a decrease in gross electricity revenue of $26 million and a decrease in gross gas revenue of $26 million. The decrease in gross electricity revenue was primarily driven by a 4 per cent decrease in the average electricity sales price compared with the same period in the prior year. The decrease in gross gas revenue was primarily driven by an 8 per cent decrease in the average gas price reflecting overall lower natural gas prices in North America following continued high shale gas production. Deducted from gross trade revenues are forward purchases, which decreased by a net $54 million.

Gross trade revenue for the nine months ended December 31, 2012 was $1,214 million, a decrease of $429 million compared with the same period in the prior year due to a decrease in gross gas revenue of $266 million and a decrease in gross electricity revenue of $163 million. The decrease in gross gas revenue was primarily driven by a 31 per cent decrease in the average gas price reflecting overall lower natural gas prices in North America following continued high shale gas production. The decrease in gross electricity revenue was primarily driven by a 23 per cent decrease in the average electricity sales price over the same period in the prior year, primarily due to lower Pacific Northwest prices as a result of higher hydro and wind generation. Deducted from gross trade revenues are forward purchases, which decreased by a net $191 million compared with the same period in the prior year, primarily due to a decrease in gas prices as well as lower forward gas purchases. Forward transactions are reported on a net basis in accordance with the Prescribed Standards. 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 months ended December 31, 2012, total operating expenses of $936 million were $88 million higher than in the same period in the prior fiscal year. The increase was primarily the result of higher amortization and depreciation expense and higher expenditures on personnel and materials and services. Total operating expenses for the nine months ended December 31, 2012 of $2,726 million were $10 million lower than in the same period in the prior fiscal year. The decrease over the prior year is due primarily to a favourable cost of energy variance partially offset by higher amortization and depreciation expense, higher personnel costs, and lower capitalization of overhead costs. The higher amortization and depreciation expense was due to higher assets in service and higher net regulatory account amortization. The higher net regulatory account amortization results primarily from a higher rate rider in the current year. Higher personnel costs were primarily due to fewer expenses transferred to capital and higher post employment benefits as a result of increased current service pension costs due to changes in discount rates. The lower capitalized costs were due to a reduction in the deferred regulatory overhead costs. As identified in the Capitalized Costs discussion in this MD&A, the rate impact of this increase in operating costs (reduction in capitalized overhead costs) on transition to the Prescribed Standards is being smoothed over a ten year period through transfers to the IFRS Property, Plant and Equipment regulatory account.

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, 2012 were $439 million, comparable to total energy costs of $441 million in the same period in the prior fiscal year. Total energy costs, after regulatory account transfers, for the nine months ended December 31, 2012 were $1,245 million, $223 million or 15 per cent lower than in the same period in the prior fiscal year. The decrease in the nine months was primarily due to lower trade energy purchases as a result of lower average natural gas and electricity prices.

Energy costs are comprised of the following sources of supply:

	(in millions)		*(gigawatt hours)*		*($ per MWh)*	
For the three months ended December 31	**2012**	2011	**2012**	2011	**2012**[3]	2011[3]
Domestic						
Water rental payments (hydro generation)[1]	**$ 85**	$ 94	**13,159**	14,283	**$ 6.54**	$ 6.67
Purchases from Independent Power Producers	**196**	180	**2,722**	2,637	**72.01**	68.42
Other electricity purchases - Domestic	**3**	2	**122**	40	**23.87**	53.17
Gas for thermal generation	**8**	9	**43**	50	**177.43**	177.62
Transmission charges and other expenses	**8**	2	**30**	33	**-**	-
Allocation (to) from trade energy	**(6)**	(42)	**(260)**	(1,277)	**21.99**	32.98
Total Domestic Cost of Energy Before Regulatory Transfers	**294**	245	**15,816**	15,766	**18.58**	15.56
Domestic cost of energy regulatory transfers	**(2)**	40	**-**	-	**-**	-
Total Domestic	**$ 292**	$ 285	**15,816**	15,766	**$ 18.45**	$ 18.08
Trade						
Electricity – Gross	**$ 136**	$ 112	**5,257**	3,908	**$ 25.87**	$ 28.66
Less: forward electricity purchases[2]	**(46)**	(79)	**-**	-	**-**	-
Electricity – Net	**90**	33	**-**	-	**-**	-
Remarketed gas – Gross	**241**	265	**7,287**	7,102	**33.07**	37.31
Less: forward gas purchases[2]	**(207)**	(228)	**-**	-	**-**	-
Remarketedgas – Net	**34**	37	**-**	-	**-**	-
Transmission charges and other expenses	**43**	43	**-**	-	**-**	-
Allocation from (to) domestic energy	**6**	42	**260**	1,277	**21.99**	32.98
Total Trade Cost of Energy Before Regulatory Transfers	**173**	155	**12,804**	12,287	**$ 17.15**	$ 18.22
Trade net margin regulatory transfer	**(26)**	1	**-**	-	**-**	-
Total Trade	**$ 147**	$ 156	**12,804**	12,287	**$ 15.10**	$ 18.31
Total Energy Costs	**$ 439**	$ 441	**28,620**	28,053	**$ 16.95**	$ 18.18

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.*

For the nine months ended December 31	*(in millions)* **2012**	2011	*(gigawatt hours)* **2012**	2011	*($ per MWh)* **2012**[3]	2011[3]
Domestic						
Water rental payments (hydro generation)[1]	**$ 256**	$ 256	**37,745**	35,975	**$ 6.82**	$ 7.21
Purchases from Independent Power Producers	**579**	562	**8,311**	8,456	**69.67**	66.51
Other electricity purchases – Domestic	**4**	13	**163**	597	**24.00**	21.99
Gas for thermal generation	**22**	24	**90**	94	**240.60**	253.96
Transmission charges and other expenses	**(35)**	1	**79**	81	**-**	-
Allocation (to) from trade energy	**(4)**	(126)	**(238)**	(3,625)	**20.50**	33.00
Total Domestic Cost of Energy Before Regulatory Transfers	**822**	730	**46,150**	41,578	**$ 17.81**	$ 17.55
Domestic cost of energy regulatory transfers	**(11)**	71	**-**	-	**-**	-
Total Domestic	**$ 811**	$ 801	**46,150**	41,578	**$ 17.57**	$ 19.27
Trade						
Electricity – Gross	**$ 376**	$ 399	**24,445**	18,147	**$ 15.38**	$ 21.99
Less: forward electricity purchases[2]	**(165)**	(225)	**-**	-	**-**	-
Electricity – Net	**211**	174	**-**	-	**-**	-
Remarketed gas – Gross	**519**	774	**20,733**	20,617	**25.03**	37.54
Less: forward gas purchases[2]	**(444)**	(575)	**-**	-	**-**	-
Remarketed gas – Net	**75**	199	**-**	-	**-**	-
Transmission charges and other expenses	**162**	151	**-**	-	**-**	-
Allocation from (to) domestic energy	**4**	126	**238**	3,625	**20.50**	33.00
Total Trade Cost of Energy Before Regulatory Transfers	**452**	650	**45,416**	42,389	**$ 12.11**	$ 20.64
Trade net margin regulatory transfer	**(18)**	17	**-**	-	**-**	-
Total Trade	**$ 434**	$ 667	**45,416**	42,389	**$ 11.71**	$ 21.04
Total Energy Costs	**$ 1,245**	$ 1,468	**91,566**	83,967	**$ 14.66**	$ 20.16

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 $294 million for the three months ended December 31, 2012 were $49 million, or 20 per cent higher than in the same period in the prior year. For the nine months ended December 31, 2012, domestic energy costs before regulatory transfers of $822 million were $92 million or 13 per cent higher than in the same period in the prior year. The increase in both periods was the result of surplus energy sales which were 450 GWh higher for the quarter and 4,777 GWh higher for the nine month period than in the same periods in the prior fiscal year as a result of higher water inflows during the spring and summer of 2012. The higher water inflows, lack of system flexibility due to high reservoir levels, and risk of spill contributed to higher hydro generation volumes and surplus energy in the first half of the fiscal year, while lower load in the third quarter also contributed to surplus energy during the period. Purchases from Independent Power Producers (IPPs) also contributed to the higher energy costs and water transactions with Bonneville Power Administration (BPA) related to the Non-Treaty Storage at Mica increased energy costs in the quarter and reduced energy costs for the nine month period.

During the quarter, higher IPP purchase volumes resulted from five IPPs achieving commercial operations during the current fiscal year, in addition to three IPPs that achieved commercial operations and commenced deliveries in the fourth quarter of fiscal 2012, and at higher rates. For the nine month period, IPP purchase volumes were lower due to a curtailment agreement effective April 2012 with one IPP which reduced deliveries in the current fiscal year.

Under an agreement effective September 2011, and renegotiated effective April 2012, with BPA to operate Non-Treaty Storage at Mica, when the Company stores water from its portion of non-treaty storage it is required to pay the value of the reduced energy flowing through the U.S. Federal Columbia River as determined by the market price of energy at that time. When the Company releases water from its portion of non-treaty storage, it is entitled to the value of the additional energy flowing through the U.S. Federal Columbia River. During the quarter, the Company was in a net storage position and this resulted in an additional $7 million in energy costs in the period which are included in Transmission charges and other expenses. For the nine month period, the Company had net releases of water that reduced energy costs by $41 million, resulting in a net credit in Transmission charges and other expenses of $35 million year to date.

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

Trade Energy Costs

Gross trade energy costs for the three months ended December 31, 2012 were $377 million, consistent with the same period in the prior year. A $24 million decrease in gross gas purchase costs was offset by a $24 million increase in gross trade electricity purchases. The decrease in gross gas purchases was primarily due to an 11 per cent decrease in the average gas price, consistent with its decrease in gross gas revenue. Deducted from gross trade energy costs are forward purchases, which decreased by a net $54 million compared with the same period in the prior year.

Gross trade energy costs for the nine months ended December 31, 2012 were $895 million, a decrease of $278 million compared with the same period in the prior year primarily due to a $255 million decrease in gross gas purchase costs and a $23 million decrease in gross trade electricity purchases. The decrease in gross gas purchases was due to a 33 per cent decrease in the average gas price, consistent with the decrease in gross gas revenue. Trade electricity purchase costs decreased due to a 30 per cent decrease in the average electricity purchase price primarily due to lower Pacific Northwest prices as a result of higher hydro and wind generation. Deducted from gross trade energy costs are forward purchases, which decreased by a net $191 million compared with the same period in the prior year, primarily due to a decrease in gas prices as well as lower forward gas purchases. Forward purchases are netted against forward sales within gross revenue in accordance with the Prescribed Standards. Variances between actual and planned trade income (which includes trade energy costs) are deferred to the TIDA.

Water Inflows

Usable system inflows for fiscal 2013 are forecast to be 109 per cent of average, with inflows to the Williston Reservoir on the Peace River system at 110 per cent and the Kinbasket Reservoir on the Columbia River system at 110 per cent of average. Usable system inflows were approximately 108 per cent of average in fiscal 2012. For the summer of 2012, both Williston and Kinbasket reservoirs spilled substantial volumes of surplus water as a result of the high inflows, with the result that usable system inflows for fiscal 2013 will be significantly less than total system inflows.

The Company's reservoirs have been managed such that the combined system storage in BC Hydro reservoirs at December 31, 2012 was 112 per cent of average (average for 1986 – 2011), with the Williston and Kinbasket reservoirs at 110 per cent and 118 per cent of average, respectively. In comparison, combined system storage at December 31, 2011 was 113 per cent of average.

PERSONNEL EXPENSES

Personnel expenses include labour, benefits and post employment benefits. Personnel costs for the three months ended December 31, 2012 of $128 million were $22 million or 21 per cent higher than in the same period in the prior fiscal year. For the nine months ended December 31, 2012, personnel costs of $391 million were $20 million or 5 per cent higher than in the same period in the prior fiscal year. The increases were primarily due to fewer expenses capitalized in the current fiscal year and increased post employment benefit costs due to a decrease in the discount rate used to calculate current service pension costs.

MATERIALS AND EXTERNAL SERVICES

Expenditures on materials and external services for the three and nine months ended December 31, 2012 of $149 million and $429 million, respectively, were $14 million and $8 million higher, respectively, than in the same periods in the prior fiscal year, primarily the result of higher maintenance and other operational activities.

CAPITALIZED COSTS

Capitalized costs are overhead costs incurred to support capital expenditures and are transferred from operating costs to property, plant and equipment. The Prescribed Standards are different than CGAAP and only allow direct overhead costs to be capitalized to property, plant and equipment, with the effect that under the Prescribed Standards there is a decrease in property, plant and equipment and a corresponding increase in operating costs. The rate impact of this increase in operating costs on transition to the Prescribed Standards is being smoothed over a ten year period through transfers to the IFRS Property, Plant and Equipment regulatory account. Capitalized costs to either property, plant and equipment or the associated regulatory accounts for the three and nine months ended December 31, 2012 were $66 million and $193 million, respectively, comparable to capitalized costs of $70 million and $210 million, respectively, in the same periods in the prior fiscal year.

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 months ended December 31, 2012, amortization and depreciation expense was $239 million, $42 million or 21 per cent higher than in the same period in the prior fiscal year. For the nine months ended December 31, 2012, amortization and depreciation expense was $705 million, $143 million or 25 per cent higher than in the same period in the prior fiscal year. The increases were primarily due to higher assets in service in the current year and higher net regulatory account amortization.

Increased net regulatory account amortization resulted primarily from higher recovery of energy deferral account balances due to the DARR of 5 per cent in effect in fiscal 2013 ($128 million recovery for the nine month period) as compared to the DARR of 2.5 per cent in effect in fiscal 2012 ($62 million recovery for the nine month period). Regulatory account amortization in fiscal 2013 also includes the amortization of regulatory accounts established for the deferral of impacts arising from transition to the Prescribed Standards, including the IFRS Pensions and Other Post Employment Benefits regulatory account. Also contributing to the increase in net regulatory account amortization were the fiscal 2012 cumulative year to date reduction of DSM regulatory account amortization for a change in the amortization period from 10 to 15 years and the amortization of the fiscal 2012 opening balances of the Finance Charges, Taxes and Amortization of Capital Additions regulatory accounts.

GRANTS AND TAXES

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 and taxes for the three and nine months ended December 31, 2012 of $48 million and $145 million, respectively, were comparable to the same periods in the prior fiscal year.

OTHER COSTS (RECOVERIES)

Other costs (recoveries) primarily include gains and losses on the disposal of assets and certain cost recoveries classified as operating costs. For the three months ended December 31, 2012, other costs net of recoveries were $7 million higher than the same period in the prior fiscal year. For the nine months ended December 31, 2012, other costs net of recoveries of $4 million were $18 million higher than in the same period in the prior fiscal year. The increases were due to higher losses incurred on asset disposals and retirements in the current periods.

FINANCE CHARGES

Finance charges after net regulatory transfers for the three months ended December 31, 2012 of $137 million were $8 million or 6 per cent higher than in the same period in the prior fiscal year. The increase is primarily due to higher planned volume of debt issues and lower planned interest rate swap income. The increase was partially offset by lower planned regulatory charges compared to the same period in the prior year. Finance charges after net regulatory transfers for the nine months ended December 31, 2012 of $405 million were $20 million or 5 per cent higher than in the same period in the prior fiscal year. The increase is primarily due to higher planned volume of debt issues in the current year and lower planned other recoveries primarily due to lower planned interest rate swap income and net higher planned regulatory charges in the current year compared to the prior year. The increase was partially offset by higher 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*	*For the nine months ended December 31*
Variances between forecast and actual costs		
Energy deferral accounts	$ 69	$ 23
Finance charges	(12)	(32)
Other	(3)	(15)
	54	(24)
Deferral of costs for future recovery in rates		
Demand Side Management	24	80
Site C	17	55
Smart Metering and Infrastructure	25	66
Environmental Provisions	-	49
First Nations	5	14
IFRS Property, Plant and Equipment	49	147
Other	1	5
	121	416
Rate Smoothing Account	(11)	(29)
Amortization of regulatory accounts	(79)	(227)
Interest on regulatory accounts	13	40
Net change in regulatory accounts	$ 98	$ 176

For the three and nine months ended December 31, 2012, net additions after amortization to the Company's regulatory accounts were $98 million and $176 million, respectively. The net asset balance in the regulatory asset and liability accounts as at December 31, 2012 was an asset of $4,211 million compared to an asset of $4,035 million at March 31, 2012.

Additions to the regulatory accounts during the three and nine months ended December 31, 2012 included:

- Transfers to the energy deferral accounts due to unfavourable variances between forecast and actual domestic energy costs, domestic load and trade income, partially offset by favourable variances between forecast and actual other energy sales due to high water inflows resulting in higher surplus energy sales.
- Planned expenditures on DSM projects, which support energy conservation, Site C project and SMI.
- Transfers to the Environmental Provisions regulatory account reflect increases required to provisions for asbestos and PCB contamination.
- Transfers to the IFRS Property, Plant and Equipment regulatory account are 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.

Decreases in the regulatory accounts during the period included:

- Transfers from the Finance Charges regulatory account due to favourable variances to the forecast.
- Transfers from the Rate Smoothing regulatory account smooth the rate increases over the three years covered by the Amended RRA. The balance of the Rate Smoothing regulatory account will be fully drawn down by the end of fiscal 2014.

ACCOUNTING CHANGES

EXPLANATION OF TRANSITION TO THE PRESCRIBED STANDARDS

On April 1, 2012, the Company adopted 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). The Company prepared its condensed consolidated interim financial statements for the three and nine month periods ended December 31, 2012 in accordance with IFRS, except that in accordance with the aforementioned legislation, it applies regulatory accounting in accordance with ASC 980. The application of ASC 980 results in the Company recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the BCUC for inclusion in future customer rates. In accordance with IFRS, such costs and recoveries would otherwise be included in the determination of comprehensive income in the year the amounts are incurred. The comparative periods included in these financial statements have been restated to the Prescribed Standards. The Company's previously issued interim and annual financial statements prior to and including the year ended March 31, 2012 were prepared in accordance with CGAAP.

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 year to date at December 31, 2012 is $68 million which is below 85 per cent of the Company's net income due to the 80:20 cap.

LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At December 31, 2012, Powerex was owed US $265 million (CDN $264 million) plus interest by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. The Federal Energy Regulatory Commission (FERC) has concluded that because of a dysfunctional energy market in California between October 2000 and June 2001, certain market-wide refunds will have to be paid by energy providers, including Powerex, to various California parties. It is expected that the receivables owed to Powerex will be offset against the market-wide refund amount that Powerex is required to pay.

The Company has elected not to report information regarding provisions as this information could prejudice the Company's position in ongoing litigation.

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 2013 is 11.73 per cent, and is lower than the prior year's allowed rate of 14.38 per cent due to changes to the effective tax rate for FortisBC Energy Inc. upon which BC Hydro's rate of return is based and the elimination of the return on equity adder that was in place in fiscal 2012.

Heritage Special Direction No. HC2 defines equity for rate-setting purposes (Deemed Equity) as 30 per cent of BC Hydro's rate base, which is comprised of a working capital allowance, assets in service (excluding leased assets), and DSM expenditures, less contributions in aid of construction and Columbia River Treaty contributions.

DAWSON CREEK/CHETWYND AREA TRANSMISSION UPGRADE PROJECT

On July 11, 2011, the Company filed an application with the BCUC for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission (DCAT) Upgrade Project. This project proposes to address electricity supply constraints in the southern Peace region of the province and meet significant forecasted load growth in that region attributable to the development of the Montney natural gas field. The project involves the construction of a new substation, a new 230 kV transmission line and the expansion of an existing substation at an estimated cost of approximately $220 million.

On October 10, 2012, the BCUC issued its decision for the DCAT CPCN Application and agreed that the DCAT Upgrade Project as described in the application is needed, but has delayed issuing a CPCN until further First Nations consultation has been undertaken and BC Hydro has provided a report on the consultation activities by early April, 2013. The additional consultation requirement for the DCAT Upgrade Project will result in a delay of the original in-service date of April 2014 by six to twelve months.

JOHN HART GENERATING STATION REPLACEMENT PROJECT

On May 25, 2012, the Company filed an application for a CPCN for the John Hart Generating Station Replacement Project. This project involves replacing the existing three 1.8-kilometre long penstocks with a 2.1-kilometre tunnel through bedrock, constructing a replacement generating station beside the existing station, constructing a replacement water intake at the John Hart spillway dam, and building a new water bypass facility. The projected cost is approximately $1 billion. If approved by the BCUC, the first replacement generating unit is expected to be in service by 2017 with project completion by the end of 2018. On July 27 and September 13, 2012, the Company filed the responses to approximately 1,000 information requests from the BCUC and intervenors. On September 21, 2012, the BCUC determined that a further procedural conference was not required and the written proceeding would move to the argument phase, which was completed when the Company filed its reply argument on November 22, 2012. The Company anticipates that the BCUC will issue its decision by March 2013.

ALBERTA UTILITIES COMMISSION—HEARING ON THE ALBERTA ELECTRIC SYSTEM OPERATOR'S PROPOSED AVAILABLE TRANSFER CAPACITY RULE

On December 5, 2011, the Alberta Electric System Operator (AESO) filed a proposed rule with the Alberta Utilities Commission (AUC) to allocate available transfer capacity (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 rule because of the harm it would cause to the Company and its ratepayers. A decision on the rule is expected to be issued by the AUC in early 2013.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the nine months ended December 31, 2012 was $549 million, compared with cash flow provided by operating activities of $674 million in the same period in the prior fiscal year. The decrease was primarily due to changes in working capital relative to the same period in the prior year mainly as a result of decreased collections of account receivable, lower net income and higher interest paid.

The long-term debt balance net of sinking funds at December 31, 2012 was $14.0 billion, compared with $12.8 billion at March 31, 2012. The increase was mainly as a result of net long-term bond issues totaling $1.2 billion ($1.0 billion par value), partially offset by a decrease in debt due to the mark to market of certain debt issues in economic fair value hedging relationships.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2012**	2011	**2012**	2011
Distribution system improvements and expansion	**$ 75**	$ 77	**$ 224**	$ 229
Generation replacements and expansion	**108**	111	**312**	336
Transmission lines and substation replacements & expansion	**243**	144	**598**	379
Smart Metering and Infrastructure program (SMI)	**46**	80	**220**	150
General, including computers, vehicles and building improvements	**48**	42	**119**	146
Total Property, Plant and Equipment Expenditures	**$ 520**	$ 454	**$ 1,473**	$ 1,240

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 the effect of accruals related to these expenditures. To reflect BC Hydro's transition to the Prescribed Standards, the December 31, 2011 total property, plant and equipment expenditures have been restated to $1,240 million from $1,385 million.

Generation capital expenditures were $24 million lower year to date compared with the same period in the prior fiscal year mainly due to decreased spending in fiscal 2013 on the Fort Nelson Resource Smart Upgrade project and the Bridge-River Townsite Redevelopment and on the GMS Spillway Slope Stabilization project, offset partially by increased spending on the Ruskin Dam and Powerhouse Upgrade, Mica Unit 5&6 Installation and GMS Unit 1 to 5 Turbine Rehabilitation.

Transmission capital expenditures were $99 million higher in the third quarter and $219 million higher year to date compared with the same periods in the prior fiscal year primarily attributable to increased expenditures on the Northwest Transmission Line (NTL), Interior to Lower Mainland (ILM) project, Burnaby-New Westminster Transmission, Meridian Transformer, Seymour Arms Series Capacitor and Long Lake and other new projects added to implementation phase, partially offset by lower spend on the Columbia Valley Transmission (CVT) and other projects placed in-service.

SMI capital expenditures were $34 million lower in the third quarter and were $70 million higher year to date compared with the same periods in the prior fiscal year. Lower expenditures in the third quarter are due to lower spend on meter equipment as almost all meters were purchased by August 2012. The increase in the year to date spend is due to the project being well into the implementation phase in fiscal 2013 with the installation of meters, telecom and information technology infrastructure all in progress. The purchase and installation of more expensive demand and energy meters starting in April 2012 also contributed to higher costs in fiscal 2013 compared to fiscal 2012.

General capital expenditures were $27 million lower year to date compared to the prior fiscal year mainly due to decreases in spend on vehicle purchases and lower spend on information technology projects with the completion of the new human resource system in June 2011.

RISK MANAGEMENT

The Company 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 strives to manage significant risks in conformity with the provisions of the international standard ISO 31000, *Risk Management – Principles and Guidelines*, or in conformity with the provisions of other 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.

In addition to 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, 2012, which should be read in conjunction with this section, the following risks impacted the Company's results for the quarter ended December 31, 2012:

LOAD/ENERGY RESOURCE BALANCE

System inflows, market prices, and domestic load influence cost of energy. The system inflow energy for fiscal 2012 was 8 per cent above average. Fiscal 2013 had unusually high runoff until July and then very dry conditions during the late summer. The system inflow energy for fiscal 2013 is now expected to be about 9 per cent above normal. Net market sales for fiscal 2013 are now forecast to be 6,000 GWh (equivalent to 11 per cent of our domestic load).

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. Demand for the large industrial customers is particularly uncertain 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 regularly models the projected supply-demand balance of the system over the short term to plan optimum system operations and over the medium term in an effort to cost-effectively meet demand.

ORGANIZATIONAL RISK

The Company's voluntary attrition continues to be a concern among employees in trades and specialized technical roles. Project structures have been established to provide focused attraction and retention strategies for priority roles where voluntary attrition is a concern: Engineers, CPC Technologists, Power Line Technicians, Cable Splicers, Station Electricians, and Field Managers. The Company continues work on a strategic workforce plan for fiscal 2014 to fiscal 2020 to assess the potential gaps between long-term labour demand and supply, and propose strategies to close these gaps. This plan is expected to be approved and in place by the start of fiscal 2014.

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 2012 forecasted a net income for fiscal 2013 at $566 million. The Service Plan included a 3.91 per cent interim rate increase for fiscal 2013.

Subsequent to the February 2012 Service Plan, the Government issued Direction No. 3 on May 22, 2012 to the BCUC which included, among other things, the setting of the interim rate increase in fiscal 2013 of 3.91 per cent as final and lowering the allowed rate of return on deemed equity for fiscal 2013 from 12.75 per cent to 11.73 per cent. BC Hydro prepared an updated forecast in January 2013 that forecasts net income for fiscal 2013 at $516 million.

The January 2013 forecast is incorporated into the February 2013 Service Plan that forecasts a net income of $545 million for fiscal 2014. The Service Plan includes a BCUC approved 1.44 per cent rate increase for fiscal 2014. The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, 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 2014 assumes average water inflows (100 per cent of average), customer load of 52,701 GWh, average market energy prices of US $29.23/MWh, short-term interest rates of 1.39 per cent and a U.S. dollar exchange rate of US$1.0119.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2012**	2011	**2012**	2011
Revenues				
Domestic	**$ 1,085**	$ 993	**$ 2,866**	$ 2,647
Trade	**200**	198	**605**	843
	1,285	1,191	**3,471**	3,490
Expenses				
Operating Expenses (Note 4)	**936**	848	**2,726**	2,736
Finance Charges (Note 5)	**137**	129	**405**	385
Net Income	**212**	214	**340**	369
Other Comprehensive Income (Loss):				
Effective portion of changes in fair value of derivatives designated as cash flow hedges	**8**	(19)	**(10)**	8
Reclassification to income on derivatives designated as cash flow hedges	**(8)**	13	**6**	(22)
Foreign currency translation gains (losses)	**2**	(12)	**(1)**	26
Other Comprehensive Income (Loss)	**2**	(18)	**(5)**	12
Total **Comprehensive Income**	**$ 214**	$ 196	**$ 335**	$ 381

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 2012***	*As at March 31 2012*
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 86**	$ 12
Accounts receivable and accrued revenue	**669**	595
Inventories (Note 7)	**159**	142
Prepaid expenses	**77**	147
Current portion of derivative financial instrument assets	**65**	140
	1,056	1,036
Non-Current Assets		
Property, plant and equipment (Note 8)	**16,965**	15,991
Intangible assets (Note 8)	**428**	412
Regulatory assets (Note 9)	**4,510**	4,314
Sinking funds	**109**	105
Derivative financial instrument assets	**33**	42
	22,045	20,864
	$ 23,101	$ 21,900
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Notes 11 and 13)	**$ 1,147**	$ 1,431
Current portion of long-term debt (Note 10)	**3,421**	2,896
Current portion of derivative financial instrument liabilities	**152**	123
	4,720	4,450
Non-Current Liabilities		
Long-term debt (Note 10)	**10,667**	10,054
Regulatory liabilities (Note 9)	**299**	279
Derivative financial instrument liabilities, long-term	**91**	189
Contributions in aid of construction	**1,194**	1,106
Post employment benefits	**1,201**	1,182
Other long-term liabilities (Note 13)	**1,443**	1,421
	14,895	14,231
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**3,347**	3,075
Accumulated other comprehensive income	**79**	84
	3,486	3,219
	$ 23,101	$ 21,900

Commitments and Contingencies (Notes 8 and 14)

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, 2011	$ -	$ 74	$ 74	$ 60	$ 2,747	$ 2,881
Payment to the Province	-	-	-	-	(54)	(54)
Comprehensive Income (Loss)	26	(14)	12	-	369	381
Balance, December 31, 2011	$ 26	$ 60	$ 86	$ 60	$ 3,062	$ 3,208
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

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* 2012	2011
Operating Activities		
Net income	**$ 340**	$ 369
Regulatory account transfers	**(342)**	(124)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 6)	**244**	110
Amortization and depreciation expense	**467**	444
Unrealized gains on mark-to-market	**(25)**	(30)
Interest accrual	**473**	466
Other items	**5**	4
	1,162	1,239
Changes in:		
Accounts receivable and accrued revenue	**(72)**	(49)
Prepaid expenses	**69**	91
Inventories	**(17)**	(28)
Accounts payable and accrued liabilities	**(177)**	(180)
Contributions in aid of construction	**111**	98
	(86)	(68)
Interest paid	**(527)**	(497)
Cash provided by operating activities	**549**	674
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(1,415)**	(1,338)
Cash used in investing activities	**(1,415)**	(1,338)
Financing Activities		
Long-term debt:		
Issued	**1,373**	1,372
Retired	**(200)**	-
Receipt of revolving borrowings	**4,524**	3,783
Repayment of revolving borrowings	**(4,508)**	(3,536)
Payment to the Province (Note 11)	**(230)**	(463)
Other items	**(19)**	(27)
Cash provided by financing activities	**940**	1,129
Increase in cash and cash equivalents	**74**	465
Cash and cash equivalents, beginning of period	**12**	27
Cash and cash equivalents, end of period	**$ 86**	$ 492

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. (Powerex), 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. All intercompany transactions and balances are eliminated upon consolidation.

The Company accounts for its one third interest in the Waneta Dam and generating facility as a joint operation. The consolidated financial statements includes BC Hydro's proportionate share of the Waneta Dam and generating facility and BC Hydro's liabilities and expenses, 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 the Waneta Dam and generating facility.

NOTE 2: BASIS OF PRESENTATION

(a) 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 otherwise be included in the determination of comprehensive income in the year the amounts are incurred.

The impact of the application of ASC 980 on these condensed consolidated interim financial statements with respect to BC Hydro's regulatory accounts is described in Note 9. The accounting policies adopted under the Prescribed Standards have been applied consistently to all periods presented in these financial statements and by all subsidiaries of BC Hydro.

These condensed consolidated interim statements have been prepared by management in accordance with the principles of IAS 34, *Interim Financial Reporting* and IFRS 1, *First Time Adoption of IFRS* and were prepared using the same accounting policies as described in the Company's interim consolidated financial statements for the three months ended June 30, 2012. Accordingly, certain disclosures normally included in annual financial statements have been omitted or condensed. In prior years, these financial statements were prepared in compliance with Canadian Generally Accepted Accounting Principles (CGAAP). In preparing these interim statements, management has amended certain accounting methods previously applied in the CGAAP consolidated financial statements to comply with the Prescribed Standards. The comparative figures for the prior year were restated to reflect these amendments. An explanation of how the transition to the Prescribed Standards has affected the reported financial position, financial performance and cash flows of BC Hydro is provided in Note 16.

These condensed consolidated interim financial statements were approved by the Board of Directors on February 7, 2013.

(b) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for financial instruments that are accounted for at fair value through profit and loss (temporary investments, designated long-term debt and derivative financial instruments) and available for sale financial assets (U.S. sinking funds).

(c) Functional and Presentation Currency

The functional currency of BC Hydro and all of its subsidiaries, except for Powerex, is the Canadian dollar. Powerex's functional currency is the U.S. dollar. These consolidated financial statements are presented in Canadian dollars and financial information has been rounded to the nearest million unless otherwise stated.

(d) Key Assumptions and Significant Judgements

The preparation of financial statements in conformity with the Prescribed Standards requires management to make judgements, estimates and assumptions in respect of the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from those judgements, estimates, and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. There have been no changes in key assumptions and significant judgements from those disclosed in the June 30, 2012 interim financial statements.

NOTE 3: SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies that have been used in the preparation of these condensed consolidated interim financial statements are summarized in the Company's first quarter financial statements for the three months ended June 30, 2012.

NOTE 4: OPERATING EXPENSES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2012**	2011	**2012**	2011
Electricity and gas purchases	**$ 293**	$ 303	**$ 861**	$ 1,102
Water rentals	**100**	98	**256**	252
Transmission charges	**46**	40	**128**	114
Personnel expenses	**128**	106	**391**	371
Materials and external services	**149**	135	**429**	421
Amortization and depreciation (Note 6)	**239**	197	**705**	562
Grants and taxes	**48**	47	**145**	138
Capitalized costs	**(66)**	(70)	**(193)**	(210)
Other costs / (recoveries)	**(1)**	(8)	**4**	(14)
Total	**$ 936**	$ 848	**$ 2,726**	$ 2,736

NOTE 5: FINANCE CHARGES

(in millions)	*For the three months ended December 31* 2012	2011	*For the nine months ended December 31* 2012	2011
Interest on long-term debt	**$ 172**	$ 157	**$ 485**	$ 461
Interest on finance lease liabilities	**6**	6	**20**	17
Net interest on defined benefit plan obligations	**49**	47	**148**	142
Less: Capitalized interest	**(20)**	(21)	**(55)**	(41)
Total finance costs	**207**	189	**598**	579
Expected return on defined benefit plan assets	**(46)**	(44)	**(138)**	(132)
Other recoveries	**(24)**	(16)	**(55)**	(62)
Total	**$ 137**	$ 129	**$ 405**	$ 385

NOTE 6: AMORTIZATION AND DEPRECIATION

(in millions)	*For the three months ended December 31* 2012	2011	*For the nine months ended December 31* 2012	2011
Depreciation of property, plant and equipment	**$ 139**	$ 131	**$ 418**	$ 385
Amortization of intangible assets	**15**	16	**43**	42
Amortization of regulatory accounts and other	**85**	50	**244**	135
Total	**$ 239**	$ 197	**$ 705**	$ 562

NOTE 7: INVENTORIES

During the three month and nine month periods ended December 31, 2012, an impairment of $1 million and an impairment recovery of $15 million (fiscal 2012—impairment of $15 million and $22 million, respectively) were recorded in electricity and gas purchases to adjust the cost of natural gas in storage to its net realizable value as a result of changes in market prices. At December 31, 2012, $46 million (2011—$61 million) of the carrying value of natural gas in storage 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 months ended December 31, 2012 were $520 million and $1,473 million, respectively (2011—$454 million and $1,240 million, respectively).

As of December 31, 2012, BC Hydro has contractual commitments to spend $1,175 million on major property, plant and equipment projects.

NOTE 9: RATE REGULATION

REGULATORY ACCOUNTS

The following regulatory assets and liabilities have been established through rate regulation. For the three and nine months ended December 31, 2012, the impact of regulatory accounting has resulted in increases of $98 million and $176 million to net income (three and nine months ended December 31, 2011—$60 million increase and $210 million increase, respectively).

(in millions)	*March 31 2012 CGAAP*	*Transition to Prescribed Standards (Note 16)*	*April 1 2012*	*Addition (Reduction)*	*Amortization*	*Net Change*	*December 31 2012*
Regulatory Assets							
Heritage Deferral Account	$ 244	$ -	$ 244	$ (68)	$ (40)	$ (108)	$ 136
Non-Heritage Deferral Account	367	62	429	100	(60)	40	469
Trade Income Deferral Account	175	30	205	18	(27)	(9)	196
Demand-Side Management Programs	646	(8)	638	80	(40)	40	678
First Nation Negotiations, Litigation & Settlement Costs	543	-	543	14	(5)	9	552
Non-Current Pension Cost	55	322	377	(6)	(13)	(19)	358
Site C	181	-	181	62	-	62	243
CIA Amortization Variance	68	-	68	5	-	5	73
Environmental Provisions	234	88	322	49	(4)	45	367
Smart Metering and Infrastructure	92	-	92	70	-	70	162
Finance Charges	6	43	49	(32)	-	(32)	17
IFRS Pension & Other Post Employment Benefits	-	762	762	-	(29)	(29)	733
IFRS Property, Plant and Equipment	-	254	254	147	(3)	144	398
Other Regulatory Accounts	150	-	150	1	(23)	(22)	128
Total Regulatory Assets	2,761	1,553	4,314	440	(244)	196	4,510
Regulatory Liabilities							
Future Removal and Site Restoration Costs	120	(16)	104	-	(17)	(17)	87
Rate Smoothing	70	-	70	29	-	29	99
Foreign Exchange Gains and Losses	103	-	103	-	-	-	103
Other Regulatory Accounts	2	-	2	8	-	8	10
Total Regulatory Liabilities	295	(16)	279	37	(17)	20	299
Net Regulatory Asset	$ 2,466	$ 1,569	$ 4,035	$ 403	$ (227)	$ 176	$ 4,211

OTHER REGULATORY ACCOUNTS

Other regulatory asset and liability accounts with individual balances less than $50 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.

On January 17, 2013, the BCUC approved BC Hydro's application to establish the Asbestos Remediation regulatory account to defer asbestos remediation costs arising from implementation of the Asbestos Management Program set by WorkSafe BC and BC Hydro's implementation of IFRS.

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, 2012, the Company issued bonds with a par value of $300 million (2011—$300 million), a weighted average effective interest rate of 3.30 per cent (2011—3.89 per cent) and a weighted average term to maturity of 27 years (2011—31 years). For the nine month period ended December 31, 2012, the Company issued bonds with a par value of $1.2 billion (2011—$1.4 billion), a weighted average effective interest rate of 3.31 per cent (2011—4.28 per cent) and a weighted average term to maturity of 26 years (2011—31 years). Debt issue costs associated with the transactions were $6 million (2011—$9 million).

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 period, there were no changes in the approach to capital management.

The debt to equity ratio at December 31, 2012 and March 31, 2012 was as follows:

(in millions)	*As at December 31* **2012**	*As at March 31* 2012
Total debt, net of sinking funds	**$ 13,979**	$ 12,845
Less: Cash and cash equivalents	**(86)**	(12)
Net Debt	**$ 13,893**	$ 12,833
Retained earnings	**$ 3,347**	$ 3,075
Contributed surplus	**60**	60
Accumulated other comprehensive income	**79**	84
Total Equity	**$ 3,486**	$ 3,219
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 to date at December 31, 2012 is $68 million (March 31, 2012—$230 million), is included in accounts payable and accrued liabilities and is less than 85 per cent of the net income due to the 80:20 cap.

NOTE 12: POST EMPLOYMENT BENEFITS

The expense recognized in the statement of comprehensive income for the Company's benefit plans for the three and nine months ended December 31, 2012 was $23 million and $68 million (2011—$21 million and $63 million, respectively).

Contributions to the registered defined benefit pension plan for the three and nine months ended December 31, 2012 were $12 million and $36 million, respectively (2011—$12 million and $37 million), respectively.

NOTE 13: OTHER LONG-TERM LIABILITIES

(in millions)	***December 31*** **2012**	*March 31* 2012
Provisions		
Environmental liabilities	**$ 343**	$ 301
Asset retirement obligations	**63**	94
Other	**29**	3
Total Provisions	**435**	398
First Nations liabilities	**388**	393
Finance lease obligations	**296**	309
Deferred revenue	**426**	418
	1,545	1,518
Less: Current portion, included in accounts payable and accrued liabilities	**(102)**	(97)
Total	**$ 1,443**	$ 1,421

NOTE 14: COMMITMENTS AND CONTINGENCIES

LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At December 31, 2012, Powerex was owed US $265 million (CDN $264 million) plus interest by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. The Federal Energy Regulatory Commission (FERC) has concluded that because of a dysfunctional energy market in California between October 2000 and June 2001, certain market-wide refunds will have to be paid by energy providers, including Powerex, to various California parties. It is expected that the receivables owed to Powerex will be offset against the market-wide refund amount that Powerex is required to pay.

The Company has elected not to report information regarding provisions as this information could prejudice the Company's position in ongoing litigation.

NOTE 15: SEASONALITY OF OPERATING RESULTS

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

NOTE 16: EXPLANATION OF TRANSITION TO THE PRESCRIBED STANDARDS

In preparing its opening statement of financial position, BC Hydro has adjusted amounts reported previously in financial statements prepared in accordance with CGAAP. An explanation of how the transition from CGAAP to the Prescribed Standards has affected BC Hydro's financial position, financial performance and cash flows is set out in the following tables and the notes that accompany the tables:

Reconciliation of the Consolidated Statement of Financial Position Prepared According to the Prescribed Standards

		December 31, 2011		
(in millions)	Note	Canadian GAAP	Effect of Transition	Prescribed Standards
ASSETS				
Current Assets				
Cash and cash equivalents		$ 492	$ -	$ 492
Accounts receivable and accrued revenue		619	-	619
Inventories		156	-	156
Prepaid expenses		65	-	65
Current portion of derivative financial instrument assets	n	96	-	96
		1,428	-	1,428
Non-Current Assets				
Property, plant and equipment	a-e,g,o	16,083	(357)	15,726
Intangible assets		382	-	382
Regulatory assets	t	2,468	1,181	3,649
Investments held in sinking funds		105	-	105
Employee future benefits	h	276	(276)	-
Derivative financial instrument assets	n	43	1	44
		19,357	549	19,906
		$ 20,785	$ 549	$ 21,334
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities	n,o	$ 1,037	$ 17	$ 1,054
Current portion of long-term debt	j	3,234	10	3,244
Current portion of derivative financial instrument liabilities	n	62	3	65
		4,333	30	4,363
Non-Current Liabilities				
Long-term debt	j,l	10,053	35	10,088
Regulatory liabilities	t	296	(1)	295
Derivative financial instrument liabilities		173	-	173
Contibutions in aid	c	1,088	(3)	1,085
Post employment benefits	h	365	495	860
Other long-term liabilities	f-g,o,r	1,303	(41)	1,262
		13,278	485	13,763
Shareholder's Equity				
Contributed surplus		60	-	60
Retained earnings	b-h,j-o,r	3,062	-	3,062
Accumulated other comprehensive income	k,m,r	52	34	86
		3,174	34	3,208
		$ 20,785	$ 549	$ 21,334

For presentation purposes, the current portion of other long-term liabilities has been reclassified and included in accounts payable and accrued liabilities in the comparative periods under CGAAP, increasing accounts payable and accrued liabilities and decreasing other long-term liabilities by $39 million at December 31, 2011.

Reconciliation of Consolidated Statement of Comprehensive Income

		For the three months ended December 31, 2011			*For the nine months ended December 31, 2011*		
(in millions)	Note	Canadian GAAP	Effect of Transition	Prescribed Standards	Canadian GAAP	Effect of Transition	Prescribed Standards
Revenues							
Domestic	c,n,p	$ 984	$ 9	$ 993	$ 2,618	$ 29	$ 2,647
Trade	t	238	(40)	198	837	6	843
		1,222	(31)	1,191	3,455	35	3,490
Expenses							
Operating expenses (Note 4)	b-d,f-i,o-q	884	(36)	848	2,713	23	2,736
Finance charges (Note 5)	e,f,i-m,o,q	124	5	129	373	12	385
Net Income		$ 214	$ -	$ 214	$ 369	$ -	$ 369
Other Comprehensive Income (Loss):							
Effective portion of changes in fair value on derivatives designated as cash flow hedges	k,m	$ (32)	$ 13	$ (19)	$ 21	$ (13)	$ 8
Reclassification to income on derivatives designated as cash flow hedges	m	22	(9)	13	(43)	21	(22)
Foreign currency translation gains (losses)	r	-	(12)	(12)	-	26	26
Other Comprehensive Income (Loss)		$ (10)	$ (8)	$ (18)	$ (22)	$ 34	$ 12
Total Comprehensive Income		$ 204	$ (8)	$ 196	$ 347	$ 34	$ 381

NOTES TO THE RECONCILIATION OF THE CONSOLIDATED STATEMENT OF FINANCIAL POSITION AND CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME PREPARED ACCORDING TO THE PRESCRIBED STANDARDS:

The following explanations disclose the key impacts arising on transition from CGAAP to the Prescribed Standards. The net transitional impacts to retained earnings, contributed surplus and actuarial losses in accumulated other comprehensive income as at April 1, 2011 and for the three and nine months ended December 31, 2011 have been deferred to regulatory assets and liabilities on the statement of financial position for regulatory accounting purposes. As identified in BC Hydro's Amended fiscal 2012–2014 Revenue Requirements Application (Amended RRA), BC Hydro has requested approval to defer IFRS retained earnings impacts that are not within the current scope of existing regulatory deferral accounts. Refer to Regulatory Note 9 for further information on regulatory accounts.

(a) Fair Value as Deemed Cost

With the application of the deemed cost exemption, the net book value of property, plant and equipment and intangible assets for BC Hydro entities subject to rate regulation at April 1, 2011 have become the opening cost of property, plant and equipment and intangible assets under the Prescribed Standards except for finance leases and asset retirement obligation assets.

(b) Componentization

CGAAP permits component accounting for property, plant and equipment but does not require componentization of assets. IFRS requires the componentization of significant parts of an asset where the useful life or the depreciation method of the part of the asset differs from the remainder of the asset. In addition certain expenditures under CGAAP are eligible for capitalization and are considered asset components under IFRS. The impact of componentization under IFRS as at and for the three and nine months ended December 31, 2011 was a decrease in property, plant and equipment of $1 million and $5 million, respectively and a corresponding increase in operating expenses of $1 million and $5 million, respectively due to the reduction in the useful life of the component assets compared to the life of the parent asset.

(c) Mass Asset Retirements

Under CGAAP, the Company did not record any gains or losses for assets that are tracked on a pooled basis except when entire pools or a substantial portion of an asset pool is retired prior to being fully amortized. IFRS requires that gains and losses on disposal of assets be recognized immediately in income, and not charged or credited to accumulated amortization. The impact of the IFRS requirement for the three and nine months ended December 31, 2011 was losses of $8 million and $22 million recognized for the retirement of pooled assets offset by recognition of associated deferred contributions in aid into revenue in the amount $1 million and $3 million, respectively.

(d) Capital Overhead

Under CGAAP, there are expenditures allocated to capital that are associated with capital programs that are no longer eligible for capitalization under IFRS as they are not considered directly attributable to the construction of the asset. The effect of this difference as at and for the three and nine months ended December 31, 2011 was a decrease in property, plant and equipment and a corresponding increase in operating costs in the amount of $52 million and $155 million, respectively.

(e) Interest During Construction

Under CGAAP, the Company capitalized interest on all capital projects regardless of project duration period. Under IFRS, interest costs are only capitalized in relation to an asset that takes a "substantial period of time" to prepare for its intended use. The Company considers a substantial period of time to be in excess of six months; therefore interest costs that relate to capital projects with less than six months duration to prepare for their intended use are no longer eligible for capitalization and must be expensed in the period incurred. The effect as at and for the three and nine months ended December 31, 2011 was a decrease in property, plant and equipment and a corresponding increase in finance charges of $2 million and $5 million, respectively.

(f) New Provisions

Measurement requirements for provisions under IFRS have a lower recognition threshold than CGAAP and as a result, upon transition to the Prescribed Standards, an ARO has been estimated in connection with removal of asbestos at various locations. This resulted in an increase in total current and non-current provisions of $26 million and a corresponding decrease in retained earnings as at April 1, 2011. The accretion adjustment for the three and nine months ended December 31, 2011 was an increase of less than $1 million in finance charges and a corresponding increase to the environmental liability.

(g) Provision Re-Measurement

Under CGAAP, there was no requirement to re-measure provisions for changes in discount rates. Under IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*, provisions are reviewed at the end of each reporting period and adjusted to reflect the current best estimate, including a reassessment of discount rates where the present value of a provision has been calculated. Upon transition to the Prescribed Standards, the revaluation of these provisions to reflect the appropriate discount rates at the end of each reporting period resulted in an increase in total provisions of $26 million and a corresponding decrease in retained earnings as at April 1, 2011. There was an increase in provisions and provision expense for the three and nine months ended December 31, 2011 of $6 million and $25 million, respectively.

The Company elected to use an exemption allowing ARO related assets to be re-measured on a simplified approach at the transition date rather than perform full detailed ARO calculations. At the transition date, the re-measurement increased ARO liabilities by $6 million, increased property, plant and equipment by $4 million and decreased retained earnings by $2 million. In addition to the transition date adjustment, the re-measurement increased the ARO liabilities and property, plant and equipment by $3 million and $13 million for the three and nine months ended December 31, 2011, respectively.

(h) Actuarial Gains and Losses Recognition

Under CGAAP, the Company recognized actuarial gains and losses in net income over the employees' remaining service period. Under IFRS, the Company's policy is to recognize all actuarial gains and losses in other comprehensive income. As permitted by IFRS 1, the Company has elected to recognize all previously unrecognized actuarial gains and losses that existed at the date of transition in opening retained earnings for all of its employee post-employment and defined benefit plans. Under CGAAP, the Company recognized past service costs over the expected average remaining service life of the employees. IAS 39 requires all vested past service costs to be recognized immediately. On the date of transition, the Company recognized all vested past service costs into opening retained earnings with a resulting decrease in the post retirement benefit liability.

The effect as at the date of the transition resulted in a decrease to the defined benefit asset of $296 million, an increase in the defined benefit obligation of $500 million and a decrease in opening retained earnings of $796 million. The reversal of amortization previously recognized under CGAAP resulted in a decrease of $8 million and $26 million to the pension benefit obligation and expense for three and nine months ended December 31, 2011, respectively. In addition, there was a $20 million reduction in the defined benefit asset offset by an increase in the defined benefit obligation.

In accordance with the Prescribed Standards, the impact at transition net of the fiscal 2012 reversal of amortization previously recognized under CGAAP has been deferred to the IFRS Pension & Other Post Employment Benefits regulatory account.

(i) Interest Reclassification

Under IFRS, interest on defined benefit obligations and interest on defined benefit plan assets are classified as finance charges rather than as operating costs under CGAAP. The effect was a reclassification of net interest expense on the plan obligations and assets from operating costs to finance charges of $3 million and $9 million for the three and nine months ended December 31, 2011, respectively.

(j) Designation of Previously Recognized Financial Instruments

As permitted by IFRS 1, the Company has elected to designate a number of previously recognized financial liabilities as a financial liability at fair value through the profit or loss at the date of transition. The Company has discontinued fair value hedge accounting with respect to a number of its Canadian denominated debt issues and has applied this exemption to the underlying debt under the discontinued hedging relationship. This increased the current portion of long term debt by $10 million, increased long term debt by $53 million and decreased opening retained earnings by $63 million as at April 1, 2011. There was an additional decrease in long-term debt of $8 million and $22 million and a corresponding decrease in finance charges for the three and nine months ended December 31, 2011, respectively.

(k) Ineffectiveness On Cash Flow Hedges

Certain methods to assess hedge effectiveness under CGAAP are no longer permitted under IFRS. The resulting transitional adjustment recorded to reflect the hedge ineffectiveness that would have been realized under IFRS in prior years as at the date of transition was less than $1 million. The impact at transition was reversed by adjustments recorded for the nine months ended December 31, 2011.

(l) Fair Value of Debt Issuance

Certain previous Canadian debt issues were issued to the Province of BC at yields that were higher or lower than market yields (off market rates). This was allowed under CGAAP under the related parties guidance. IFRS requires all debt to be recorded at its fair value at inception. This adjustment is required to reflect the accounting standards under IFRS for off market debt issues. This transitional adjustment results in an increase to debt of $5 million, an increase to contributed surplus of $11 million, and a decrease to retained earnings of $16 million as at April 1, 2011.The amortization of this transitional adjustment for the three and nine months ended December 31, 2011 resulted in a decrease to finance charges and long-term debt of less than $1 million and $1 million, respectively.

(m) De-Designation of Cash Flow Hedging Relationship as at April 1, 2011

This transitional adjustment reverses the mark-to-market adjustment from other comprehensive income to finance charges for the comparative period due to the de-designation of specific hedges. The effect is an increase in other comprehensive income and finance charges for the three and nine months ended December 31, 2011 of $4 million and $8 million, respectively.

There was an additional adjustment recorded for the amortization of accumulated other comprehensive income amounts due to the de-designation of hedge accounting on April 1, 2011 for transition to the Prescribed Standards. The transitional adjustment resulted in an increase in finance charges and accumulated other comprehensive income for the three months and nine months ended December 31, 2011 of less than $1 million and $1 million, respectively.

(n) New Derivatives

Under IFRS, the lack of a specified notional quantity does not preclude a contract from meeting the criteria for classification as a derivative financial instrument, as is the case under CGAAP. As a result, on transition to the Prescribed Standards, a number of transactions previously recognized by the Company as an executory contract under CGAAP are now recognized on a fair value basis under IFRS. The impact on the date of transition was a decrease of $3 million to retained earnings offset by an increase for both derivative financial instrument assets and liabilities of $1 million and $6 million, respectively and a decrease in accounts payable and accrued liabilities of $2 million.

There was a further increase in derivative financial instruments of $1 million and an offsetting decrease in accounts payable and other accrued liabilities for the three months ended December 31, 2011. There was an increase in accounts payable and accrued liabilities of $2 million and a decrease of $4 million in derivative financial instrument liabilities offset by an increase in revenue of $2 million for the nine months ended December 31, 2011.

(o) Leases

On the date of transition to the Prescribed Standards, an energy purchase agreement was assessed as containing an embedded lease under IFRIC 4. The arrangement was subsequently assessed under IAS 17, *Leases* and was classified as a finance lease. Adjustments were also made to two energy purchase agreements that were classified as finance leases under CGAAP. One agreement was reclassified from a finance lease to an operating lease under IFRS. Another agreement was re-measured using the interest rate implicit in the agreement.

The following table summarizes the impact of the adjustments:

	Incremental Increase (Decrease)		
(in millions)	As at April 1, 2011	For the three months ended December 31, 2011	For the nine months ended December 31, 2011
Property, plant and equipment	$ (196)	$ 2	$ 8
Lease obligation liability	(137)	2	6
Accounts payable and accrued liabilities	-	(1)	8
Retained earnings	(59)	-	-
Finance charges	-	1	3
Operating costs	-	(2)	3

(p) Contributions in Aid of Construction (CIA)

Under IFRS, contributions that are received by the Company to fund customer connections to the ongoing supply of electricity will continue to be recorded as deferred revenue as in the case under CGAAP. Under IFRS, amortization of the deferred revenue will be recorded as revenue, rather than as depreciation expense under CGAAP. The effect for the three and nine months ended December 31, 2011 was a reclassification from depreciation expense to revenue of $10 million and $30 million, respectively.

(q) Accretion expense reclassification

Under IFRS, accretion expense is classified as finance charges rather than as operating costs under CGAAP. The reclassification adjustment from operating costs to finance charges was less than $1 million and $1 million for the three and nine months ended December 31, 2011, respectively.

(r) Functional Currency

In accordance with IFRS 1, the Company elected to deem all foreign currency translation differences arising on consolidation of Powerex to be nil at the date of transition, April 1, 2011. The foreign currency translation adjustment was a loss of $12 million and gain of $26 million recognized in other comprehensive income for the three and nine months ended December 31, 2011 respectively. The impact of foreign currency translation on consolidation is not deferred for regulatory purposes.

In addition, as a result of the change in Powerex's functional currency, Powerex recorded adjustments to its foreign exchange gains and losses as at April 1, 2011 and for the three and nine months ended December 31, 2011. The impact of these adjustments was to decrease retained earnings by $3 million at April 1, 2011 and to record a foreign exchange gain of $7 million and a loss of $25 million for the three and nine months ended December 31, 2011, respectively. The impact of these differences has been deferred for regulatory purposes in the Trade Income Deferral Account.

(s) Change in Classification of Cash Flows

The following table is a reconciliation of the change in classification of cash flows arising from the transition to the Prescribed Standards for the nine months ended December 31, 2011:

(in millions)	Canadian GAAP	Effect of Transition to Prescribed Standards	Prescribed Standards
Net cash used in operating activities	$ 615	$ 59	$ 674
Net cash provided by financing activities	1,129	-	1,129
Net cash provided by investing activities	(1,279)	(59)	(1,338)

The adjustments to the cash flow classification arise as a result of the presentation of the Company's CIA amortization and an adjustment to remove capitalized interest from property, plant and equipment expenditures, which were reclassified from investing activities to operating activities.

(t) Deferral of Prescribed Standards Transitional Impacts

The Prescribed Standards transitional impacts to retained earnings, contributed surplus and actuarial losses in accumulated other comprehensive income have been deferred for regulatory purposes. The changes have increased (decreased) regulatory assets and liabilities as follows:

(in millions)	Note	Incremental Increase (Decrease) For the nine months ended December 31, 2011
Componentization	b	$ 5
Mass Asset Retirements	c	19
Capital Overhead	d	155
Interest During Construction	e	5
New Provisions	f	1
Provision Re-Measurement	g	25
Actuarial Gains and Losses Recognition	h	(26)
Designation of Previously Recognized Financial Instruments	j	(22)
Ineffectiveness of Cash Flow Hedges	k	(1)
Fair Value of Debt Issuance	l	(1)
De-Designation of Cash Flow Hedging Relationship	m	9
New Derivatives	n	(2)
Leases	o	6
Foreign Exchange	r	25
Incremental increase for the period		198
Opening transition date IFRS adjustments		984
Total cumulative increase as at the balance date		$ 1,182
Regulatory assets		$ 1,181
Regulatory liabilities		(1)
Net regulatory increase		$ 1,182

The regulatory transfer of the IFRS impacts on trade income resulted in a decrease of $40 million and increase of $6 million in trade revenue and operating costs for the three and nine months ended December 31, 2011, respectively.