THIRD QUARTER REPORT FISCAL 2012

BC hydro REGENERATION 50

British Columbia

BC HYDRO & POWER AUTHORITY MANAGEMENT DISCUSSION AND ANALYSIS

For the three and nine months ended December 31, 2011

The Management Discussion and Analysis reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the three and nine month periods ended December 31, 2011 (fiscal 2012). This section should be read in conjunction with the Management Discussion and Analysis presented in the 2011 Annual Report, the 2011 Annual Consolidated Financial Statements of BC Hydro, and the interim consolidated financial statements of BC Hydro for the three and nine month periods ended December 31, 2011 and 2010. This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of BC Hydro. 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.

BC Hydro's results for the third quarter of fiscal 2012 benefited from higher domestic margins and lower operating costs, partially offset by higher amortization expense and higher finance charges than in the same quarter in the prior year.

HIGHLIGHTS

- On November 24, 2011, BC Hydro filed an amended revenue requirement application for fiscal 2012-2014 (Amended RRA) with the British Columbia Utilities Commission (BCUC), reflecting the outcome of the government review and the related report issued on August 11, 2011. Based on BC Hydro's original F2012 – F2014 Revenue Requirements Application (Original RRA), the BCUC approved an average interim rate increase of 8 per cent effective May 1, 2011 and suspended the regulatory process for reviewing BC Hydro's Original RRA until completion of the government review of BC Hydro. The Amended RRA requests rate increases of 8.0, 3.9 and 3.9 per cent for fiscal 2012, 2013 and 2014, respectively. BC Hydro's financial results for the three and nine months ended December 31, 2011 reflect the Amended RRA.
- Inflows for fiscal 2012 are forecast to be 108 per cent of average, following two successive low water years in which system water inflows for fiscal 2011 and 2010 were 86 and 87 per cent of average, respectively. At December 31, 2011, the combined system storage in BC Hydro reservoirs was 113 per cent of average compared to 98 per cent of average at December 31, 2010.
- BC Hydro's capital plan for fiscal 2012 is $2.1 billion, an increase of $400 million over fiscal 2011, as the Company continues its programs to address load growth and renew and revitalize its aging infrastructure. Property, plant and equipment expenditures for the quarter of $501 million were $126 million higher than in the same period in the prior year primarily due to higher expenditures on generation replacement and expansion projects, transmission projects, and on the Smart Metering and Infrastructure Program (SMI).

	For the three months ended December 31			*For the nine months ended December 31*		
(in millions)	**2011**	2010	Change	**2011**	2010	Change
Net Income	**$ 214**	$ 171	$ 43	**$ 369**	$ 381	$ (12)
Accrued Payment to the Province	**$ 54**	$ 146	$ (92)	**$ 54**	$ 216	$ (162)
Number of Domestic Customers	**N/A**	N/A	N/A	**1,867,437**	1,848,206	19,231
GWh Sold (Domestic)	**13,817**	13,702	115	**37,785**	36,386	1,399
Total Reservoir Storage (GWh)	**N/A**	N/A	N/A	**23,558**	20,665	2,893

(in millions)	***As at December 31, 2011***	*As at March 31, 2011*	*Change*
Total Assets	**$ 20,785**	$ 19,479	$ 1,306
Retained Earnings	**$ 3,062**	$ 2,747	$ 315
Debt to Equity	**80 : 20**	80 : 20	N/A

CONSOLIDATED RESULTS OF OPERATIONS

As a rate-regulated utility, BC Hydro applies various accounting policies that are acceptable under Canadian generally accepted accounting principles (GAAP) for rate regulated enterprises but differ from enterprises that do not operate in a rate-regulated environment. These policies allow for the deferral of amounts that under GAAP 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 transfers to regulatory accounts reflected in net income on the consolidated statement of operations include: variances between forecast and actual amounts for certain costs, including cost of energy, trade income and finance charges; certain amounts incurred in the current period that are deferred for future recovery in rates (such as demand-side management expenditures and liability provisions); interest accrued on regulatory accounts where allowed; and amortization of regulatory accounts into income. Transfers to regulatory accounts during the three and nine month periods ended December 31, 2011 were minimal, increasing net income by $11 million and $12 million, respectively. The transfers were primarily due to expenditures on demand side management programs (DSM), Site C and SMI, partially offset by transfers from the Heritage Deferral Account (HDA) and Non-Heritage Deferral Account (NHDA) for lower than planned cost of energy and from the Trade Income Deferral Account (TIDA) for higher than planned trade income.

Net income for the three months ended December 31, 2011 was $214 million, $43 million higher than the three months ended December 31, 2010. On a year to date basis, net income was $369 million, $12 million lower than the same period in 2010. The changes in net income for the three and nine months ended December 31, 2011 over the comparable periods in 2010 were primarily due to the following:

- Domestic margins for the three and nine month periods ended December 31, 2011 were $47 million and $112 million higher, respectively, than in the same periods in the prior year, reflecting higher revenues due to higher average customer rates in the current year;
- Other operating costs for the three months ended December 31, 2011 were $17 million lower than in the same period in the prior year primarily due to lower expenditures on personnel, materials and services, and lower provisions and other operating costs due to the write-down of two regulatory asset account balances in the third quarter of fiscal 2011 as directed by the Negotiated Settlement Agreement (NSA) on BC Hydro's F2011 RRA. These favourable variances were partially offset by higher amortization expense. For the nine months ended December 31, 2011, other operating costs were $64 million higher than in the same period in the prior year due to higher amortization expense and higher personnel costs, partially offset by lower expenditures on materials and services, lower provisions and other expense, and higher capitalized operating costs;
- Finance charges after regulatory transfers for the three and nine months ended December 31, 2011 were $18 million and $50 million higher than the comparable periods in the prior year primarily due to higher debt levels to support capital spending.

REVENUES

	(in millions)		(gigawatt hours)	
		(Revised)[2]		(Revised)[2]
For the three months ended December 31	**2011**	2010	**2011**	2010
Domestic				
Residential	**$ 449**	$ 414	**5,154**	5,093
Light industrial and commercial	**345**	322	**4,635**	4,641
Large industrial	**152**	140	**3,483**	3,457
Other energy sales	**50**	55	**544**	521
Total Domestic Revenue Before Regulatory Transfer	**996**	931	**13,817**	13,712
Domestic rate smoothing and load variance regulatory transfer	**(12)**	5	**—**	—
Total Domestic	**$ 984**	$ 936	**13,817**	13,712
Trade				
Electricity – Gross	**$ 231**	$ 252	**5,191**	6,275
Less: forward electricity purchases[1]	**(69)**	(136)	**—**	—
Electricity – Net	**162**	116	**—**	—
Gas – Gross	**278**	252	**7,202**	6,504
Less: forward gas purchases[1]	**(202)**	(245)	**—**	—
Gas – Net	**76**	7	**—**	—
Total Trade	**$ 238**	$ 123	**12,393**	12,779
Total	**$ 1,222**	$ 1,059	**26,210**	26,491

	(in millions)		(gigawatt hours)	
		(Revised)[2]		(Revised)[2]
For the nine months ended December 31	**2011**	2010	**2011**	2010
Domestic				
Residential	**$ 1,081**	$ 969	**12,700**	12,183
Light industrial and commercial	**983**	925	**13,306**	13,272
Large industrial	**430**	399	**10,040**	9,870
Other energy sales	**147**	173	**1,738**	1,071
Total Domestic Revenue Before Regulatory Transfer	**2,641**	2,466	**37,785**	36,396
Domestic rate smoothing and load variance regulatory transfer	**(23)**	22	**—**	—
Total Domestic	**$ 2,618**	$ 2,488	**37,785**	36,396
Trade				
Electricity – Gross	**$ 837**	$ 799	**21,858**	19,995
Less: forward electricity purchases[1]	**(225)**	(475)	**—**	—
Electricity – Net	**612**	324	**—**	—
Gas – Gross	**804**	632	**20,309**	15,806
Less: forward gas purchases[1]	**(579)**	(540)	**—**	—
Gas – Net	**225**	92	**—**	—
Total Trade	**$ 837**	$ 416	**42,167**	35,801
Total	**$ 3,455**	$ 2,904	**79,952**	72,197

[1] *Forward purchases include derivatives which are deducted from gross sales in accordance with GAAP.*

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

Total revenue for the three and nine month periods ended December 31, 2011 was $1,222 million and $3,455 million, respectively, was $163 million and $551 million higher, respectively, compared with the same periods in the prior year. Domestic revenues were higher in the three and nine month periods primarily due to higher average customer rates in all customer classes and higher consumption by residential and large industrial customers. Trade revenues increased in the quarter due to higher gas trade sales volumes. Year to date trade revenues increased over the same period in the prior year due to increases in electricity and gas sales volumes.

DOMESTIC REVENUES

Total domestic revenues after regulatory transfers for the three month period ended December 31, 2011 were $984 million, a $48 million increase over the comparable period in the prior year. Total domestic revenues after regulatory transfers for the nine months ended December 31, 2011 were $2,618 million, an increase of $130 million over the comparable period in the prior year. The increase in domestic revenue for the three and nine month periods was primarily due to higher average customer rates in the current fiscal year, reflecting the interim average rate increase approved by the BCUC of 8 per cent effective May 1, 2011. Domestic sales volumes for the three and nine month periods were higher due to increased consumption by residential customers primarily due to colder weather conditions and by large industrial customers primarily as a result of the temporary closure of a plant in the Chemicals sector for an upgrade in fiscal 2011 which significantly reduced consumption in that fiscal year. Variances between actual and planned load are deferred to the NHDA.

TRADE REVENUES

Powerex, a wholly owned subsidiary of BC Hydro, is a key participant in energy markets across North America, buying and supplying wholesale power, natural gas, ancillary services, and financial energy products and, more recently, environmental products with an expanding list of trade partners.

BC Hydro'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 BC Hydro balance its system by being able to import energy to meet domestic demand when there is a supply shortage in the system due to such factors as low water inflows. Exports are made only after ensuring domestic demand requirements can be met.

Gross trade revenue for the three months ended December 31, 2011 was $509 million, an increase of $5 million over the comparable period in prior year due to an increase in gross gas revenue of $26 million, partially offset by a decrease in gross electricity sales of $21 million. The increase in gas revenue was primarily driven by an 11 per cent increase in gas sales volumes reflecting Powerex's increased gas trading activities, partially offset by an 8 per cent decrease in the average gas sales prices over the prior year. The decrease in gross electricity sales was primarily driven by a 17 per cent decrease in electricity sales volumes and a 3 per cent decrease in the average electricity sales price. Deducted from gross trade revenues are forward purchases, which decreased by a net $110 million compared with the prior year. Forward transactions are recorded on a net basis in accordance with GAAP.

Gross trade revenue for the nine months ended December 31, 2011 was $1,641 million, an increase of $210 million over the comparable period in prior year due to an increase in gross gas revenue of $172 million and an increase in gross electricity revenue of $38 million. The increase in gas revenue was primarily driven by a 28 per cent increase in gas sales volumes reflecting Powerex's increased gas trading activities. The increase in gross electricity revenue was primarily due to a 9 per cent increase in electricity sales volumes. Deducted from gross trade revenues are forward purchases, which decreased by a net $211 million compared with the prior year. Forward transactions are reported on a net basis in accordance with GAAP. Variances between actual and planned trade revenue are deferred to the TIDA.

OPERATING COSTS

For the three and nine months ended December 31, 2011, total operating costs of $883 million and $2,713 million were $102 million and $513 million higher, respectively, than in the same periods in the prior year. The increase in the quarter was primarily due to increases in the cost of energy due to higher planned trade energy costs and higher amortization expense due to more assets in service and higher amortization of regulatory account balances. This was partially offset by lower personnel costs, lower expenditures on materials and services and lower other operating costs reflecting the write down of certain regulatory asset accounts in the third quarter of fiscal 2011 which increased other operating costs in that period. Year to date, the increase was primarily due to higher planned domestic and trade energy costs, higher personnel expenditures and higher amortization expense, partially offset by lower other operating costs, lower expenditures on materials and services and higher capitalized operating costs.

COST OF ENERGY

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.

Energy costs are comprised of the following sources of supply:

	(in millions)		*(gigawatt hours)*		*($ per MWh)*	
		(Revised)[5]		*(Revised)*[5]		*(Revised)*[5]
For the three months ended December 31	**2011**	2010	**2011**	2010	**2011**[4]	2010[4]
Domestic						
Water rental payments (hydro generation)[1]	**$ 93**	$ 87	**14,283**	11,804	**$ 6.63**	$ 7.40
Purchases from Independent Power Producers	**179**	178	**2,637**	2,763	**67.92**	64.57
Other electricity purchases – Domestic	**2**	30	**40**	829	**53.17**	36.35
Gas for thermal generation	**9**	13	**50**	95	**177.62**	132.55
Transmission charges and other expenses[2]	**2**	(2)	**33**	41	**—**	—
Allocation (to) from trade energy	**(42)**	(7)	**(1,277)**	(166)	**32.98**	37.31
Total Domestic Cost of Energy Before Regulatory Transfers	**243**	299	**15,766**	15,366	**15.44**	19.45
Domestic cost of energy regulatory transfers	**42**	(15)	**—**	—	**—**	—
Total Domestic	**$ 285**	$ 284	**15,766**	15,366	**$ 15.44**	$ 19.45
Trade						
Electricity – Gross	**$ 111**	$ 196	**3,908**	6,118	**$ 28.40**	$ 32.04
Less: forward electricity purchases[3]	**(69)**	(136)	**—**	—	**—**	—
Electricity – Net	**42**	60	**—**	—	**—**	—
Remarketed gas – Gross	**266**	240	**7,102**	6,820	**37.45**	35.19
Less: forward gas purchases[3]	**(202)**	(245)	**—**	—	**—**	—
Remarketed gas – Net	**64**	(5)	**—**	—	**—**	—
Transmission charges and other expenses	**42**	46	**—**	—	**—**	—
Allocation from (to) domestic energy	**42**	7	**1,277**	166	**32.98**	37.31
Total Trade Cost of Energy Before Regulatory Transfers	**190**	108	**12,287**	13,104	**21.07**	18.64
Trade net margin regulatory transfers	**6**	(30)	**—**	—	**—**	—
Total Trade	**$ 196**	$ 78	**12,287**	13,104	**$ 21.59**	$ 16.38
Total Energy Costs	**$ 481**	$ 362	**28,053**	28,470	**$ 19.61**	$ 17.51

	(in millions)		(gigawatt hours)		($ per MWh)	
		(Revised)[5]		(Revised)[5]		(Revised)[5]
For the nine months ended December 31	**2011**	2010	**2011**	2010	**2011**[4]	2010[4]
Domestic						
Water rental payments (hydro generation)[1]	**$ 255**	$ 208	**35,975**	27,600	**$ 7.19**	$ 7.69
Purchases from Independent Power Producers	**548**	532	**8,456**	8,727	**64.82**	61.01
Other electricity purchases – Domestic	**13**	114	**597**	3,145	**21.99**	36.29
Gas for thermal generation	**24**	34	**94**	194	**253.96**	173.16
Transmission charges and other expenses[2]	**1**	22	**81**	80	**—**	—
Allocation (to) from trade energy	**(126)**	25	**(3,625)**	586	**33.00**	39.41
Total Domestic Cost of Energy Before Regulatory Transfers	**715**	935	**41,578**	40,332	**$ 17.21**	$ 23.18
Domestic cost of energy regulatory transfers	**86**	(152)	**—**	—	**—**	—
Total Domestic	**$ 801**	$ 783	**41,578**	40,332	**$ 19.26**	$ 19.41
Trade						
Electricity – Gross	**$ 398**	$ 636	**17,437**	20,294	**$ 22.83**	$ 31.34
Less: forward electricity purchases[3]	**(225)**	(475)	**—**	—	**—**	—
Electricity – Net	**173**	161	**—**	—	**—**	—
Remarketed gas – Gross	**771**	588	**20,617**	16,099	**37.40**	36.52
Less: forward gas purchases[3]	**(579)**	(540)	**—**	—	**—**	—
Remarketed gas – Net	**192**	48	**—**	—	**—**	—
Transmission charges and other expenses	**151**	140	**—**	—	**—**	—
Allocation from (to) domestic energy	**126**	(25)	**3,625**	(586)	**33.00**	39.41
Total Trade Cost of Energy Before Regulatory Transfers	**642**	324	**41,679**	35,807	**20.80**	22.31
Trade net margin regulatory transfers	**19**	(94)	**—**	—	—	—
Total Trade	**$ 661**	$ 230	**41,679**	35,807	**$ 21.26**	$ 19.70
Total Energy Costs	**$ 1,462**	$ 1,013	**83,257**	76,139	**$ 20.27**	$ 19.55

[1] Total GWh is net of storage exchange.

[2] Total GWh for transmission charges and other expenses relate only to non-integrated costs.

[3] 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.

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

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

Total energy costs, after regulatory account transfers, for the three months ended December 31, 2011 were $481 million, $119 million or 33 per cent higher than the same period last year. For the nine months ended December 31, 2011, total energy costs, after regulatory account transfers, were $1,462 million, $449 million or 44 per cent higher than in the same period last year. The increase in the three and nine month periods was primarily due to higher trade energy purchase costs due to higher gas purchase volumes and prices, partially offset by lower electricity volumes and prices.

DOMESTIC ENERGY COSTS

Domestic energy costs before regulatory transfers of $243 million for the three months ended December 31, 2011 were $56 million or 19 per cent lower than in the same period in the prior year. For the nine months ended December 31, 2011, domestic energy costs before regulatory transfers of $715 million were $220 million or 24 per cent lower than in the same period in the prior year. In the first nine months of the current fiscal year, higher water inflows, system flexibility and risk of spill all contributed to higher hydro generation volumes, reduced market energy purchase volumes for domestic load requirements, and lower purchases for future trade as compared to the same period in the prior fiscal year. This is reflected in lower market energy purchase costs and net exports, rather than net purchases, for trade, partially offset by higher water rental costs. Lower transmission charges for the nine month period reflect the integration of the British Columbia Transmission Corporation (BCTC) with BC Hydro in the second quarter of fiscal 2011. Transmission costs recognized by BC Hydro as cost of energy in the first quarter of fiscal 2011, when the two companies were separate entities, were reclassified as other operating costs in the current year as a result of the inclusion of transmission activities in BC Hydro's operations. 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 quarter ended December 31, 2011 were $461 million, a decrease of $28 million over the comparable period in prior year. The decrease was primarily due to an $85 million decrease in electricity purchased for trade, partly offset by a $35 million increase in the allocation from domestic energy and a $26 million increase in gas purchase costs. The decrease in electricity purchased for trade was primarily due to a 36 per cent decrease in purchase volumes and an 11 per cent decrease in the average electricity price. The increase in gross gas purchases was due to a 6 per cent increase in the average gas purchase price and a 4 per cent increase in purchases volumes reflecting Powerex's increased gas trading activities. Deducted from gross trade energy costs are forward purchases, which decreased by a net $110 million compared with the prior year. Forward purchases are netted against forward sales within gross revenue in accordance with GAAP.

Gross trade energy costs for the nine months ended December 31, 2011 were $1,446, an increase of $107 million over the comparable period in prior year primarily due to a $183 million increase in gas purchase costs and $151 million increase in the allocation from domestic energy, partially offset by a $238 million decrease in electricity purchased for trade. The increase in gross gas purchases was due to a 28 per cent increase in purchase volumes, consistent with the increase in sales volumes and primarily due to increased gas trading activities. Electricity purchase costs decreased primarily due to a 27 per cent decrease in the average electricity purchase price. The decrease in average electricity purchase price was primarily due to lower Pacific Northwest prices as a result of higher water levels in the current fiscal year. Deducted from gross trade energy costs are forward purchases, which decreased by a net $211 million compared with the prior year. Forward purchases are netted against forward sales within gross revenue in accordance with GAAP. Variances between actual and planned trade energy costs are deferred to the TIDA.

WATER INFLOWS

System wide inflows into BC Hydro's reservoirs in the third quarter of fiscal 2012 were 2 per cent above average (average from 1981–2010). Based on the December 2011 energy study, fiscal 2012 inflows are forecast to be about 108 per cent of average. There is negligible risk of spill at Williston and Kinbasket reservoirs for the balance of the fiscal year, which is typical for the time of year.

The BC Hydro reservoirs have been managed such that the combined storage in BC Hydro reservoirs at December 31, 2011 was 113 per cent of average (average 1986-2010), compared to 98 per cent of average at December 31, 2010, with the Williston reservoir on the Peace River system at 115 per cent of average, and the Kinbasket reservoir on the Columbia River system at 116 per cent of average.

PERSONNEL EXPENSES

Personnel expenses include labour, benefits and employee future benefits. Personnel costs, after net regulatory transfers, of $118 million for the three months ended December 31, 2011 were $13 million lower compared to the same period in the prior year, primarily due to favourable operational cost variances and planned workforce reductions which occurred in the month of October 2011. For the nine months ended December 31, 2011 personnel costs of $407 million were comparable to the same period in the prior year, with favourable operational cost variances and workforce reductions offset by expenditures in the current year for transmission activities included in BC Hydro's operations which were part of BCTC in the first quarter of fiscal 2011 and by a severance accrual recorded in September 2011.

MATERIALS AND EXTERNAL SERVICES

Materials and external services include expenditures for operating and maintenance materials and services provided by third parties. Expenditures on materials and external services, after net regulatory transfers, of $135 million and $421 million for the three and nine month periods ended December 31, 2011, respectively, were $9 million lower than in the same periods in the prior year. The reduction in expenditures is primarily due lower expenditures on information technology and higher expenditures required in fiscal 2011 for the integration of BCTC with BC Hydro in that year.

CAPITALIZED COSTS

Capitalized costs are overhead costs incurred to support capital expenditures and are transferred from operating costs to property, plant and equipment. Capitalized costs for the three and nine months ended December 31, 2011 were $70 million and $210 million respectively, compared to $67 million and $192 million for the same periods in the prior year and were in line with increases in capital expenditures as compared to the prior year.

AMORTIZATION AND DEPRECIATION

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, asset retirement obligation (ARO) assets, amortization of customer contributions and the amortization of certain regulatory assets and liabilities. For the three and nine month periods ended December 31, 2011, amortization and depreciation expense was $179 million and $507 million, respectively, compared with $145 million and $396 million in the same periods in the prior year. The increases were primarily due to higher assets in service as a result of BC Hydro's capital expenditure program and higher net regulatory account amortization resulting from the accelerated amortization of the Net Employment Cost and Total Finance Charges regulatory liability account balances in fiscal 2011 which significantly reduced net amortization expense in that fiscal year, partially offset by lower amortization of energy deferral accounts in the first nine months of the current fiscal year. In addition, as applied for in the Amended RRA, amortization expense for the quarter and year to date reflects an applied for change in the amortization period for DSM costs from 10 to 15 years, together with the year to date amortization of the fiscal 2012 opening balances of the Total Finance Charges, Taxes and Amortization of Capital Additions regulatory liability accounts.

GRANTS AND TAXES

As a Crown Corporation, BC Hydro is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts. Total grants, school taxes and other local taxes of $47 million and $138 million for the three and nine month periods ended December 31, 2011, respectively, were comparable to the same periods in the prior year.

OTHER COSTS

Other operating costs primarily include gains and losses on the disposal of assets and certain recoveries classified as operating costs. The fiscal 2011 amounts reflect the write-down of two regulatory asset accounts in the third quarter of fiscal 2011 as directed by the NSA for BC Hydro's F2011 RRA.

FINANCE CHARGES

Finance charges, after net regulatory transfers, for the three and nine month periods ended December 31, 2011 of $125 million and $373 million, respectively, were $18 million and $50 million higher than in the same periods in the prior year. The increase in both periods is primarily due to a higher planned volume of long-term debt issues primarily required to fund capital additions and higher planned interest rates. A negative foreign exchange variance due to the planned weakening of the Canadian dollar in the current year compared to a planned strengthening in the prior year contributed to the increases in the current fiscal year.

REGULATORY TRANSFERS

BC Hydro has established various regulatory accounts with the approval of the BCUC. Regulatory accounts allow BC Hydro 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.

The net change in regulatory accounts on the consolidated statement of operations includes: 1) the deferral of differences between planned and actual results for cost of energy (including variances related to load), trade income, and finance charges; 2) costs deferred for future recovery in rates, such as costs for DSM and Site C; and 3) interest accrued on regulatory accounts, where allowed, and amortization of regulatory accounts.

Regulatory transfers are comprised of the following:

(in millions)	*For the three months ended December 31* **2011**	2010	*For the nine months ended December 31* **2011**	2010
Variances between forecast and actual costs				
Energy deferral accounts	**$ (39)**	$ 51	**$ (90)**	$ 274
Finance charges	**9**	5	**(7)**	(11)
Other	**(4)**	3	**(6)**	(8)
	(34)	59	**(103)**	255
Deferral of costs for future recovery in rates				
Demand-Side Management	**41**	23	**105**	73
Site C	**17**	12	**59**	29
Environmental Compliance	**2**	3	**(25)**	9
SMI	**14**	—	**38**	4
Other	**23**	7	**42**	28
	97	45	**219**	143
Rate Smoothing	**(25)**	—	**(44)**	—
Amortization of regulatory accounts	**(38)**	(23)	**(96)**	(18)
Interest on regulatory accounts	**11**	11	**36**	28
Net change in regulatory accounts	**$ 11**	$ 92	**$ 12**	$ 408

For the three months ended December 31, 2011, net additions after amortization to BC Hydro's regulatory accounts was $11 million, compared with net additions of $92 million to the regulatory accounts during the same period last year. For the nine months ended December 31, 2011, net additions after amortization of BC Hydro's regulatory accounts was $12 million compared with net additions of $408 million during the same period in the prior year. The net asset balance in the regulatory asset and liability accounts as at December 31, 2011 was an asset of $2,172 million compared to $2,160 million at March 31, 2011.

The significant reduction in additions to BC Hydro's regulatory accounts in the three and nine month periods ended December 31, 2011, compared to the same periods in the prior year, was largely due to the change in net transfers to or from the energy deferral accounts. The reduction in the energy deferral accounts in the current fiscal year primarily reflects lower than planned domestic cost of energy as a result of high water inflows which reduced the requirement for market energy purchases, and lower than planned generation levels at various Independent Power Producers (IPPs) due to water inflow levels and operational outages. Reductions in the energy deferral accounts also reflect higher than planned trade income resulting from favourable price spreads in the Northwest and Alberta. In comparison, energy deferral account transfers for the same periods in fiscal 2011 reflected higher than planned domestic energy costs resulting from very low water inflows and lower than planned trade income due to low price spreads.

Other significant regulatory transfers include transfers from the Rate Smoothing Regulatory Account, which has been applied for to smooth the rate increases applied for in BC Hydro's Amended RRA over the three year period covered by the application. This regulatory account remains subject to approval by the BCUC. Expenditures on DSM projects, which support energy conservation, were higher than in the same periods in the prior year primarily due to higher levels of customer participation in incentive programs, and higher expenditures on the Site C project which reflect the increase in costs associated with environmental assessment activities being undertaken in the current fiscal year. Expenditures on SMI reflect the project moving into implementation phase in fiscal 2012. The Environmental Compliance regulatory account was adjusted in the second quarter of fiscal 2011 due to new guidelines issued by Environment Canada during the period which resulted in a $30 million reduction to BC Hydro's provision for polychlorinated biphenyl (PCB) remediation. The change in amortization of regulatory accounts primarily reflects the accelerated amortization of certain regulatory liability account balances in fiscal 2011 which significantly reduced net regulatory account amortization in that fiscal year.

FUTURE ACCOUNTING CHANGE

International Financial Reporting Standards

The *Budget Transparency and Accountability Act* (BTAA) specifies that the Government and government organizations conform to the set of standards and guidelines that comprise generally accepted accounting principles for senior governments in Canada, unless otherwise directed by Treasury Board. Accounting standards for senior government are understood to mean standards established by the Public Sector Accounting Board (PSAB), which directs Government Business Enterprises (GBEs) to adhere to International Financial Reporting Standards (IFRS). BC Hydro is classified as a GBE. In 2010, the Canadian Accounting Standards Board (AcSB) issued guidance allowing qualifying entities with rate-regulated activities be permitted, but not required, to continue applying the accounting standards in Part V of the CICA Handbook—*Accounting* for an additional year rather than adopting IFRS for annual periods beginning on or after January 1, 2011. BC Hydro is applying the deferral option.

Subsequent to the expiration of the deferral period, BC Hydro will adopt financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the BTAA and Section 9.1 of the *Financial Administration Act* (FAA). BC Hydro will prepare its consolidated financial statements in accordance with IFRS, except that in accordance with legislation, it will continue to apply regulatory accounting in accordance with the United States Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations*. 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 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.

PAYMENT TO THE PROVINCE

Under a Special Directive from the Province, BC Hydro 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 BC Hydro's distributable surplus for the most recently completed fiscal year assuming that the debt to equity ratio, as defined by the Province, after deducting the Payment, is not greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment will be based on the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The dividend accrued year to date at December 31, 2011 is $54 million which is below 85 per cent of distributable surplus due to the 80:20 cap.

Effective April 1, 2011, Order in Council (OIC) No. 021 amended Heritage Special Directive No. HC1 by changing the definition of distributable surplus used in the calculation of the Payment to mean the consolidated net income earned by BC Hydro and its subsidiaries from all sources as reflected in the consolidated audited financial statements, as compared to the previous definition in which net capitalized finance charges were deducted from consolidated net income.

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, 2011, Powerex was owed US $265 million (CDN $270 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. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

Due to the ongoing nature of the regulatory and legal proceedings against Powerex, management cannot predict the outcomes of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the California energy crisis. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that are ultimately collected or paid may differ from management's current estimates. Management has not disclosed the provision amounts or ranges of expected outcomes due to the potentially adverse effect on the process.

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. OIC No. 074 dated February 17, 2009 amended Heritage Special Direction No. HC2 to allow for an addition of 1.63 per cent to the rate of return in fiscal years 2010, 2011 and 2012. The allowed rate of return for fiscal 2012 is 14.38 per cent, and is higher than the prior year's allowed rate of 14.37 per cent due to the higher rate of return allowed for FortisBC Energy Inc. (formerly Terasen Gas Inc.), upon which BC Hydro's rate of return is based.

OIC No. 020 dated February 2, 2011, and effective April 1, 2011, amended Heritage Special Direction No. HC 2, such that BC Hydro's ROE will be based on total assets in service, changed from total debt and equity. Equity for rate-setting purposes (Deemed Equity) is now 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. From fiscal 2009 to fiscal 2011, Deemed Equity was equal to 30 per cent of the sum of BC Hydro's average debt and average equity balances for the year. The Amended RRA incorporated the changes to the ROE calculation.

Amended RRA

On November 24, 2011, BC Hydro filed an Amended RRA for fiscal 2012–2014 with the BCUC, reflecting the outcome of the government review and the related report issued on August 11, 2011. Based on BC Hydro's Original RRA, BCUC approved an average interim rate increase of 8 per cent effective May 1, 2011 and suspended the regulatory process for reviewing BC Hydro's Original RRA until completion of the government review of BC Hydro. The Amended RRA requests rate increases of 8.0, 3.9 and 3.9 per cent for fiscal 2012, 2013 and 2014, respectively. The Amended RRA filing also included the DSM Expenditure filing requesting acceptance of planned DSM expenditures for fiscal 2012 and fiscal 2013. A regulatory timetable has been established for review of the amended application. Key dates are: BC Hydro responded to the first round of Information Requests (IRs) from the BCUC and interveners on January 31, 2012; BC Hydro responding to a second round of IRs on March 27; a Negotiated Settlement Process (NSP), if any, to commence on May 28 and an oral public hearing to commence on June 18, 2012. Assuming there are no delays to the current schedule, expectations are that the BCUC will issue its decision in December 2012.

The Amended RRA reflects an updated net income forecast for fiscal 2012 of $595 million, compared to a net income forecast of $611 million in the Original RRA filing, due to a reduction in the return on equity. BC Hydro's financial results for the three and nine month periods ended December 31, 2011 reflect the filing positions included in the Amended RRA.

Ruskin Dam Upgrade Project

On February 22, 2011, BC Hydro filed an application for a Certificate of Public Convenience and Necessity (CPCN) for the Ruskin Dam Upgrade Project. This project involves replacing parts of the seismically deficient dam, and rehabilitating or replacing the powerhouse, including generating equipment and associated transmission facilities. A written hearing process for reviewing this application has been ongoing since the spring of 2011 and has been recently extended to January 12, 2012 to allow for further legal submissions to the BCUC regarding certain First Nations issues including whether an assessment of the project impacts should be expanded to include the already existing Ruskin facility. A decision is likely in March 2012.

Dawson Creek/Chetwynd Area Transmission Upgrade Project

On July 11, 2011, BC Hydro filed an application with the BCUC for a CPCN for the Dawson Creek/Chetwynd Area Transmission 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 play. 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 $250 million. If approved by the BCUC, the project is expected to be in service by October 2013. A written Information Request process was underway but was suspended on November 30, 2011 to allow BC Hydro time to collaborate with government in addressing policy issues raised by the BCUC and interveners that were not included in the CPCN application. Expectations are that the review process will resume in February 2012.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the third quarter was $309 million, compared with cash flow provided by operating activities of $172 million for the same period last year. For the nine months ended December 31, 2011, cash flow provided by operating activities was $615 million, compared with cash flow provided by operating activities of $325 million in the same period last year. For the nine month period ended December 31, 2011 the increase was primarily due to changes in actual energy costs and trade income as compared to plan in each year, partially offset by changes in working capital relative to the same period in the prior year mainly as a result of decreased collections of accounts receivable, and lower net income.

The long-term debt balance net of sinking funds at December 31, 2011 was $13.2 billion, compared with $11.5 billion at March 31, 2011. The increase was mainly a result of net long-term bond issues totaling $1.36 billion ($1.35 billion par value), an increase in revolving borrowings of $246 million and net foreign exchange revaluation losses on bonds and sinking funds of $49 million. This increase was partially offset by reductions to the debt balance due to fair value hedge accounting, amortization of premiums and sinking fund income. The net increase in borrowings in the latter part of December 2011 was primarily due to the funding of capital expenditures and the prefunding of long term debt issues of $450 million maturing on January 9, 2012.

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	
		(Revised)		(Revised)
(in millions)	**2011**	2010	**2011**	2010
Distribution improvements and expansion	**$ 100**	$ 104	**$ 300**	$ 319
Generation replacements and expansion	**126**	113	**377**	305
Transmission lines and substation replacements and expansion	**154**	108	**413**	329
General, including SMI, computers, vehicles and land rights	**121**	50	**295**	157
	$ 501	$ 375	**$ 1,385**	$ 1,110

Total property, plant and equipment expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the consolidated Statement of Cash Flows in the interim consolidated financial statements due to effect of accruals related to these expenditures.

Distribution capital expenditures decreased by $4 million in the third quarter and $19 million year to date compared with the same periods in the prior year. The decrease year to date is mainly due to lower expenditures in the current fiscal year on the Distribution protection switches replacement program, lower volume and costs for Distribution poles due to fewer third party requests, delays in system expansion and improvements approval and design work and lower customer driven work due to decreased customer demand.

Generation capital expenditures increased by $13 million in the third quarter and $72 million year to date compared with the same periods in the prior year. The increase for the quarter and year to date is mainly due to the higher spending in fiscal 2012 on Mica units 5 & 6 installations, the G.M. Shrum spillway rock slope stabilization project and the Bridge River townsite redevelopment, partially offset by lower spending on the Mica gas insulated switchgear replacement, the Cheakamus spillway gate upgrade and the Revelstoke unit 5 installation, which was placed in service in the third quarter of fiscal 2011. Also contributing to the increase year to date is higher spending on the Fort Nelson resource smart upgrade, partially offset by decreased spending on the Strathcona intake tower interim seismic upgrade, as it was placed in service in fiscal 2011.

Transmission lines and substations capital expenditures increased by $46 million in the third quarter and $84 million year to date compared with the same periods in the prior year. The increase is mainly due to higher spending in fiscal 2012 on the Northwest transmission line project, Vancouver City Central transmission project, Columbia Valley transmission project and the Interior to Lower Mainland project. Also, there were significant expenditures in the third quarter of fiscal 2012 for the Fraser River Crossing transmission line restoration project, an emergency project which was required in fiscal 2012.

General capital expenditures increased by $71 million in the third quarter and $138 million year to date compared with the same periods in the prior year. The increase for the quarter and year to date is mainly due to higher spending for SMI, as it is in the implementation phase in fiscal 2012 with the installation of meters, telecom and IT infrastructure all in progress.

RISK MANAGEMENT

BC Hydro faces risks to its business that could significantly impact its ability to achieve its short and long-term financial, social and environmental goals. The goal of risk management is not to eliminate risks, but rather to make appropriate trade-offs between competing objectives, including the cost of risk reduction, and consideration of the reward that justifies the acceptance of the risk. Similarly, BC Hydro's risk management strategies aim to mitigate risks through a consistent risk management process that is applied to day-to-day business activities as well as to specific projects and initiatives. BC Hydro's Chief Risk Officer is charged with the development of the enterprise risk management framework across all of BC Hydro, its subsidiaries and investments which provides the basis for consistent application of risk management practices. BC Hydro's Board of Directors also plays a key role in the oversight of risk management, as the Board must understand the risks being taken by BC Hydro and ensure that processes are in place to appropriately manage the risks. BC Hydro's operations involve a broad spectrum of risks ranging from those commonly associated with any business to catastrophic societal loss risks that would have severe effects on entire regions.

There were no changes in significant risks to BC Hydro's business during the nine months ended December 31, 2011 from those discussed in the Management Discussion and Analysis presented in the Annual Report for the year ended March 31, 2011, with the exception of system inflows. System inflows, market prices, and domestic load influence cost of energy. The system inflow energy for fiscal 2012 is now expected to be 8 per cent above average and the system is forecast to be in a modest net sales position for fiscal 2012.

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 March 2011 forecasted a net income of $611 million for fiscal 2012. BC Hydro filed its Amended RRA in late November 2011 that reflected the outcome of the government review and updated other assumptions in the normal course of a net income forecast update such as interest rates and water inflow levels. This forecast is incorporated into the February 2012 Service Plan that forecasts a net income of $595 million for fiscal 2012.

BC Hydro'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. The updated forecast for fiscal 2012 assumes average water inflows (100 per cent of average), customer load of 52,919 GWh, average market electricity prices of US $28.69/MWh, short-term interest rates of 0.97 per cent and a U.S. dollar exchange rate of U.S. $0.9943.

CONSOLIDATED STATEMENTS OF OPERATIONS

(unaudited)	*For the three months ended December 31*		*For the nine months ended December 31*	
		(Revised Note 1)		*(Revised Note 1)*
(in millions)	**2011**	2010	**2011**	2010
Revenues				
Domestic	**$ 984**	$ 936	**$ 2,618**	$ 2,488
Trade	**238**	123	**837**	416
	1,222	1,059	**3,455**	2,904
Expenses				
Operating Costs				
Cost of energy (Note 9)	**481**	362	**1,462**	1,013
Other operating costs (Note 9)	**402**	419	**1,251**	1,187
	883	781	**2,713**	2,200
Finance Charges	**125**	107	**373**	323
	1,008	888	**3,086**	2,523
Net Income	**$ 214**	$ 171	**$ 369**	$ 381

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited)	*For the three months ended December 31*		*For the nine months ended December 31*	
(in millions)	**2011**	2010	**2011**	2010
Net Income	**$ 214**	$ 171	**$ 369**	$ 381
Other Comprehensive Income (Loss) (Note 8)	**(10)**	11	**(22)**	(2)
Comprehensive Income	**$ 204**	$ 182	**$ 347**	$ 379

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(unaudited)	*For the nine months ended December 31*	
(in millions)	**2011**	2010
Retained Earnings, Beginning of Period	**$ 2,747**	$ 2,621
Net Income	**369**	381
Accrued Payment to the Province (Note 6)	**(54)**	(216)
Retained Earnings, End of Period	**$ 3,062**	$ 2,786

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

(unaudited) *(in millions)*	*As at December 31 2011*	*As at March 31 2011*
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 492**	$ 27
Accounts receivable and accrued revenue	**619**	569
Inventories	**156**	128
Prepaid expenses	**65**	156
Current portion of derivative financial instrument assets	**96**	198
	1,428	1,078
Other Assets		
Property, plant and equipment	**16,083**	15,211
Intangible assets	**382**	335
Regulatory assets (Note 4)	**2,468**	2,436
Sinking funds	**105**	97
Employee future benefits	**276**	296
Derivative financial instrument assets	**43**	26
	19,357	18,401
	$ 20,785	$ 19,479
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 999**	$ 1,515
Current portion of long-term debt	**3,234**	2,793
Current portion of derivative financial instrument liabilities	**62**	159
	4,295	4,467
Other Liabilities		
Long-term debt (Note 5)	**10,053**	8,851
Regulatory liabilities (Note 4)	**296**	276
Deferred contributions	**1,088**	1,012
Derivative financial instrument liabilities, long-term	**173**	212
Other long-term liabilities	**1,707**	1,781
	13,317	12,132
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**3,062**	2,747
Accumulated other comprehensive income (Note 8)	**51**	73
	3,173	2,880
	$ 20,785	$ 19,479

Commitments and Contingencies (Note 10)

See accompanying notes to the interim consolidated financial statements.

Approved on behalf of the Board:

Dan Doyle
Chairman

Tracey L. McVicar
Chair, Audit & Finance Committee

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	*For the three months ended December 31*		*For the nine months ended December 31*	
(in millions)	**2011**	2010	**2011**	2010
Operating Activities				
Net income	**$ 214**	$ 171	**$ 369**	$ 381
Regulatory account transfers	**(62)**	(120)	**(185)**	(423)
Adjustments for non-cash items:				
Amortization of regulatory accounts (Note 4)	**38**	24	**96**	18
Amortization expense and depreciation	**143**	121	**424**	354
Foreign exchange translation (gains) losses	**(3)**	(5)	**6**	(3)
Unrealized gains on mark-to-market	**(19)**	54	**(37)**	(11)
Employee benefit plan expenses	**16**	12	**47**	36
Other items	**16**	17	**11**	26
	343	274	**731**	378
Changes in non-cash working capital:				
Accounts receivable and accrued revenue	**(129)**	(196)	**(49)**	57
Accounts payable and accrued liabilities	**(68)**	(10)	**(130)**	(117)
Prepaid expenses	**152**	100	**91**	47
Inventories	**11**	4	**(28)**	(40)
	(34)	(102)	**(116)**	(53)
Cash provided by operating activities	**309**	172	**615**	325
Investing Activities				
Property, plant and equipment and intangible asset expenditures	**(506)**	(383)	**(1,375)**	(1,168)
Deferred contributions	**24**	13	**98**	50
Other items	**(4)**	(1)	**(2)**	(3)
Cash used in investing activities	**(486)**	(371)	**(1,279)**	(1,121)
Financing Activities				
Long-term debt:				
Issued	**324**	—	**1,372**	593
Retired	**—**	—	**—**	(150)
Revolving borrowings, included in long-term debt	**347**	197	**247**	408
Debt issue and related costs	**(1)**	—	**(9)**	—
Payment to the Province	**—**	—	**(463)**	(47)
Repayment of capital lease liability	**(6)**	—	**(18)**	—
Cash provided by financing activities	**664**	197	**1,129**	804
Increase (decrease) in cash and cash equivalents	**487**	(2)	**465**	8
Cash and cash equivalents, beginning of period	**5**	19	**27**	9
Cash and cash equivalents, end of period	**$ 492**	$ 17	**$ 492**	$ 17
Supplemental Disclosure of Cash Flow Information				
Interest paid	**$ 201**	$ 171	**$ 498**	$ 449
Non-cash transaction:				
Capital lease obligation included in other liabilities	**$ —**	$ —	**$ —**	$ 171

See accompanying notes to the interim consolidated financial statements.

NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) DECEMBER 31, 2011

DESCRIPTION

British Columbia Hydro and Power Authority (BC Hydro or the Company) 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.

NOTE 1: BASIS OF PRESENTATION

The interim consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) for preparation of interim financial statements and do not conform in all respects to the disclosure requirements for annual financial statements. These interim consolidated financial statements and the notes should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2011 Annual Report. These interim consolidated financial statements follow the same accounting policies as those described in BC Hydro's 2011 Annual Report. Certain amounts in the prior period statements related to revenues, cost of energy, other operating costs and finance charges have been reclassified to conform to the current year's presentation.

BC Hydro is subject to regulation by the British Columbia Utilities Commission (BCUC) which, among other things, approves the rates BC Hydro charges for its services. BC Hydro follows certain accounting practices that reflect the effects of regulation, and differ from the accounting practices for enterprises that do not operate in a rate-regulated environment (see Note 4).

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets, liabilities and commitments at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Significant items subject to management estimates and assumptions include the determination of the allowance for doubtful accounts, the fair value of sinking funds and derivative and non-derivative financial instruments, the actuarial assumptions used to value the employee future benefit plans, the useful lives of property, plant and equipment and intangible assets, amounts for accrued liabilities and contingencies including environmental, legal, First Nations, asset retirement and lease obligations, the accrual for unbilled revenue at period end, the estimated net realizable value of inventory, and regulatory assets and liabilities. Actual results could differ from these estimates.

NOTE 2: ACCOUNTING CHANGES

Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards (IFRS) for fiscal years beginning on or after January 1, 2011. However, qualifying entities with rate-regulated activities were granted an optional one-year deferral for the adoption of IFRS due to the uncertainty around the timing and adoption of a potential rate-regulated accounting standard by the International Accounting Standards Board. As a qualifying entity with rate-regulated activities, BC Hydro has elected to opt for the one-year deferral and therefore will continue to prepare its consolidated financial statements in accordance with Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook for all interim and annual periods ending on or before March 31, 2012.

Subsequent to the expiration of the deferral period, BC Hydro will adopt financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act*. In accordance with a regulation issued by the Province's Treasury Board, BC Hydro will prepare its consolidated financial statements in accordance with IFRS, except that it will continue to apply regulatory accounting in accordance with the United States Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations*. 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 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.

NOTE 3: SEASONALITY OF OPERATING RESULTS

Due to the seasonal nature of BC Hydro's operations, the interim consolidated statement of operations 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 BC Hydro's operating results.

NOTE 4: REGULATION

BC Hydro is regulated by the BCUC, and both entities are subject to general or special directives and directions issued by the Province. BC Hydro operates primarily under a cost of service regulation as prescribed by the BCUC. Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province. Revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

BC Hydro applies various accounting policies that differ from GAAP for enterprises that do not operate in a rate-regulated environment. Generally, these policies result in deferral and amortization of costs and recoveries to allow for adjustment of future rates. In the absence of rate-regulation, these amounts would otherwise be included in the determination of net income in the period the amounts are incurred. These accounting policies support BC Hydro's regulation and have been established through ongoing application to and approval by the BCUC. When a regulatory account has been or will be applied for and, in management's estimate, acceptance of deferral treatment by the BCUC is considered probable, BC Hydro defers such costs in advance of a final decision of the BCUC. If the BCUC subsequently denies the application for regulatory treatment, the remaining deferred amount is recognized in net income.

BC Hydro's filed an amended F2012–F2014 Revenue Requirements Application (Amended RRA) with the BCUC on November 24, 2011, reducing the requested rate increases to 8 per cent in fiscal 2012 and 3.9 per cent in each of fiscal 2013 and fiscal 2014, from its original filing (Original RRA) made in March 2011 which requested an average rate increase of 9.73 per cent per year in each of fiscal 2012 to fiscal 2014. In April 2011, the BCUC approved an average interim rate increase for fiscal 2012 of 8 per cent effective May 1, 2011 and suspended the regulatory process for reviewing the Original RRA until the completion of the provincial government review of BC Hydro.

Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. For the three and nine months ended December 31, 2011, the impact of regulatory accounting has resulted in increases to net income of $11 million and $12 million, respectively (three and nine months ended December 31, 2010—$92 million and $408 million increases, respectively).

(in millions)	*April 1 2011*	*Addition (Reduction)*	*Amortization*	*Net Change*	*December 31 2011*
Regulatory Assets					
Heritage Deferral Account	$ 247	$ (28)	$ (19)	$ (47)	$ 200
Non-Heritage Deferral Account	362	(9)	(28)	(37)	325
Trade Income Deferral Account	188	(26)	(15)	(41)	147
Demand-Side Management Programs	506	106	(30)	76	582
First Nation Negotiations, Litigation and Settlement Costs	399	13	(5)	8	407
Non-Current Pension Cost	72	(3)	(14)	(17)	55
Site C	104	63	—	63	167
CIA Amortization Variance	59	6	—	6	65
Environmental Compliance	231	(25)	(4)	(29)	202
SMI Deferral Account	34	40	—	40	74
Other Regulatory Accounts	234	26	(16)	10	244
Total Regulatory Assets	2,436	163	(131)	32	2,468
Regulatory Liabilities					
Future Removal and Site Restoration Costs	140	—	(14)	(14)	126
Rate Smoothing	—	44	—	44	44
Foreign Exchange Gains and Losses	106	(5)	—	(5)	101
Finance Charges	4	7	(3)	4	8
Other Regulatory Accounts	26	9	(18)	(9)	17
Total Regulatory Liabilities	276	55	(35)	20	296
Net Regulatory Asset	$ 2,160	$ 108	$ (96)	$ 12	$ 2,172

Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province. Order in Council 020 dated February 2, 2011, and effective April 1, 2011, amended Heritage Special Direction No.HC2, such that BC Hydro's return on equity is now based on total assets in service, changed from total debt and equity. Equity for rate-setting purposes (Deemed Equity) is now 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. From fiscal 2009 to fiscal 2011, Deemed Equity was equal to 30 per cent of the sum of BC Hydro's average debt and average equity balances for the year. The Amended RRA incorporates the changes to the return on equity calculation.

In April 2011, the BCUC approved BC Hydro's application to establish the Rock Bay Environmental Remediation regulatory account which allows deferral of operating costs incurred in fiscal 2011, which were approximately $2 million.

BC Hydro received approval from the BCUC in May 2011 for the establishment of the Arrow Water Systems regulatory account to defer divestiture costs relating to the transfer of the Arrow Water Systems to the Regional District of Central Kootenay and for the loss provision liability in connection with the divestiture, which total $11 million at December 31, 2011.

In July 2011, BC Hydro received approval for deferral of fiscal 2011 costs for Smart Metering and Infrastructure Project Costs (SMI), which was $15 million (asset) as at March 31, 2011. BC Hydro is requesting deferral of all SMI costs for fiscal 2012 to 2014 in the Amended RRA.

BC Hydro applied for the establishment of the F2012-F2014 Rate Smoothing regulatory account in order to smooth out the annual rate increases applied for in the Amended RRA, which was $44 million (liability) as at December 31, 2011.

In the Amended RRA, BC Hydro applied for the establishment of the Outsourcing Implementation Costs regulatory account in order to defer the costs of implementing new outsourcing arrangements for the services previously outsourced to Accenture Business Services, which was $14 million as at December 31, 2011 and is included in Other Regulatory Accounts (asset).

Other regulatory asset accounts with individual balances less than $65 million include the following: Arrow Water Systems, Contributions in Aid of Construction Amortization Variance, Capital Project Investigation Costs, Procurement Enhancement Initiative Costs, GM Shrum Unit 3 Outage, Home Purchase Option Program, Return on Equity (ROE) Adjustment, and Waneta Rate Smoothing.

Other regulatory liability accounts with individual balances less than $15 million include the following: Amortization of Capital Additions, Taxes, and Storm Damage.

NOTE 5: LONG-TERM DEBT

In the three month period ended December 31, 2011, the Company issued bonds with a par value of $300 million, a weighted average effective interest rate of 3.89 per cent and a weighted average term to maturity of 30.6 years. For the nine month period ended December 31, 2011, the Company issued bonds with a par value of $1.4 billion, a weighted average effective interest rate of 4.28 per cent and a weighted average term to maturity of 31.2 years. Debt issue costs associated with the transactions were $9 million. Subsequent to quarter end, BC Hydro repaid $450 million of long-term debt maturing on January 9, 2012.

NOTE 6: CAPITAL MANAGEMENT

Orders in Council (OIC) from the Province establish the basis for determining BC Hydro'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 the limit on the Payment to the Province if it would cause the debt to equity ratio to exceed 80:20.

BC Hydro monitors its capital structure on the basis of its debt to equity ratio. For this purpose, the applicable OIC defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and cash and cash equivalents. Equity as defined for regulatory purposes comprises retained earnings, accumulated other comprehensive income (loss) and contributed surplus.

BC Hydro manages its capital structure by virtue of limiting its Payment to the Province. During the period, there were no changes in this approach to capital management.

The debt to equity ratio at December 31, 2011 and March 31, 2011 was as follows:

(in millions)	*As at December 31 2011*	*As at March 31 2010*
Total long-term debt, net of sinking funds	**$ 13,182**	$ 11,547
Less: cash and cash equivalents	**(492)**	(27)
Net Debt	**$ 12,690**	$ 11,520
Retained earnings	**$ 3,062**	$ 2,747
Contributed surplus	**60**	60
Accumulated other comprehensive income	**51**	73
Total Equity	**$ 3,173**	$ 2,880
Net Debt to Equity Ratio	**80 : 20**	80 : 20

Payment to the Province

Under a Special Directive from the Province, BC Hydro 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 BC Hydro's distributable surplus for the most recently completed fiscal year assuming that the debt to equity ratio, as defined by the Province, after deducting the Payment, is not greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment will be equal to the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The dividend accrued year to date at December 31, 2011 is $54 million which is below 85 per cent of the distributable surplus due to the 80:20 cap.

Effective April 1, 2011, OIC No. 021 amended Heritage Special Directive No. HC1 by changing the definition of distributable surplus used in the calculation of the Payment to mean the consolidated net income earned by BC Hydro and its subsidiaries from all sources as reflected in the audited consolidated financial statements, as compared to the previous definition in which net capitalized finance charges were deducted from consolidated net income.

NOTE 7: EMPLOYEE FUTURE BENEFITS

BC Hydro's cost for employee future benefits for the three and nine months ended December 31, 2011 was $31 million and $92 million, respectively (fiscal 2011—$26 million and $82 million, respectively).

NOTE 8: OTHER COMPREHENSIVE INCOME (LOSS) & ACCUMULATED OTHER COMPREHENSIVE INCOME

Other Comprehensive Income (Loss)

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2011**	2010	**2011**	2010
Other Comprehensive Income				
Unrealized gain (loss) on derivatives designated as cash flow hedges	**$ (32)**	$ (23)	**$ 21**	$ (23)
Reclassification to income of gain (loss) on deriviatives designated as cash flow hedges	**22**	34	**(43)**	21
Other Comprehensive Income (Loss)	**$ (10)**	$ 11	**$ (22)**	$ (2)

Accumulated Other Comprehensive Income

	For the nine months ended December 31	
(in millions)	**2011**	2010
Accumulated other comprehensive income, beginning of period	**$ 73**	$ 53
Other comprehensive loss for the period	**(22)**	(2)
Accumulated Other Comprehensive Income, End of Period	**$ 51**	$ 51

NOTE 9: OPERATING COSTS

Cost of Energy

	For the three months ended December 31		For the nine months ended December 31	
(in millions)	**2011**	2010	**2011**	2010
Electricity and gas purchases	**$ 343**	$ 262	**$ 1,096**	$ 638
Water rentals	**98**	65	**252**	218
Transmission charges	**40**	35	**114**	157
Cost of Energy	**$ 481**	$ 362	**$ 1,462**	$ 1,013

Other Operating Costs

	For the three months ended December 31		For the nine months ended December 31	
(in millions)	**2011**	2010	**2011**	2010
Personnel expenses	**$ 118**	$ 131	**$ 407**	$ 402
Materials and external services	**135**	144	**421**	430
Amortization and depreciation	**179**	145	**507**	396
Capitalized costs	**(70)**	(67)	**(210)**	(192)
Grants and taxes	**47**	46	**138**	136
Other costs / recoveries	**(7)**	20	**(12)**	15
Other Operating Costs	**$ 402**	$ 419	**$ 1,251**	$ 1,187

NOTE 10: 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, 2011, Powerex was owed US $265 million (CDN $270 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. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

Due to the ongoing nature of the regulatory and legal proceedings against Powerex, management cannot predict the outcomes of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the California energy crisis. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that are ultimately collected or paid may differ from management's current estimates. Management has not disclosed the provision amounts or ranges of expected outcomes due to the potentially adverse effect on the process.