FIRST QUARTER REPORT
FISCAL 2012

BC hydro REGENERATION

BRITISH COLUMBIA

BC HYDRO & POWER AUTHORITY MANAGEMENT DISCUSSION AND ANALYSIS

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 month period ended June 30, 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 month periods ended June 30, 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 first quarter of fiscal 2012 benefited from higher domestic gross margins primarily due to higher average customer rates and higher sales volumes, offset by lower energy trading margins, higher operating costs and higher finance charges than in the same quarter in the prior year.

HIGHLIGHTS

- Net income after regulatory account transfers for the three month period ended June 30, 2011 was $92 million, comparable to $91 million for the same period in fiscal 2011.
- On April 21, 2011 the British Columbia Utilities Commission (BCUC) approved an average interim rate increase of 8 per cent effective May 1, 2011. The BCUC suspended the regulatory process for reviewing BC Hydro's F2012–F2014 Revenue Requirements Application (RRA) until completion of a government review of BC Hydro. The outcome of this review will be incorporated into an amended revenue requirement application to the BCUC expected to be filed in the fall of 2011.
- After two successive low water years in which system water inflows for fiscal 2011 and 2010 were 86 and 87 per cent of average, respectively, inflows for fiscal 2012 are forecast to be 102 per cent of average. At June 30, 2011 the combined system storage in BC Hydro reservoirs was 102 per cent of average compared to 85 per cent of average at June 30, 2010.
- BC Hydro's capital plan for fiscal 2012 is $2.2 billion, an increase of $500 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 $397 million were $80 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 June 30		
(in millions)	**2011**	2010	Change
Net Income	**$ 92**	$ 91	$ 1
Number of Domestic Customers	**1,855,457**	1,836,117	19,340
GWh Sold (Domestic)	**11,811**	11,252	559
Total Reservoir Storage (GWh)	**23,648**	20,198	3,450

(in millions)	**As at June 30 2011**	As at March 31 2011	Change
Total Assets	**$ 19,733**	$ 19,479	$ 254
Retained Earnings	**$ 2,839**	$ 2,747	$ 92
Debt to Equity	**81 : 19**	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); annual deferral or recoveries of revenue over the fiscal 2012 to fiscal 2014 period in order to smooth the rate increases applied for in BC Hydro's F2012–2014 RRA evenly over the three year period covered by the application; interest accrued on regulatory accounts where allowed; and amortization of regulatory accounts into income.

Net transfers, after amortization, to regulatory accounts of $25 million for the quarter were mainly for expenditures on demand-side management programs (DSM) and the Site C project, and the Rate Smoothing Regulatory Account which smoothes the rate increases applied for in BC Hydro's F2012–2014 RRA over the application period, partially offset by a reduction to the Trade Income Deferral Account (TIDA) as actual trade income was higher than planned.

Net income for the quarter ended June 30, 2011 was $92 million, comparable with net income of $91 million for the same period in the prior year. Higher domestic margins resulted from increased domestic revenues resulting from the 8 per cent interim average rate increase for fiscal 2012 effective May 1, 2011 and from higher consumption by residential customers due to cooler weather conditions during the first quarter of fiscal 2012. This favourable variance was offset by lower energy trading margins, higher non-energy operating costs including higher amortization expense and an increase in personnel expenditures, and higher finance charges. All variances are after the effect of applicable transfers to regulatory accounts.

REVENUES

	(in millions)	*(Revised)*	*(gigawatt hours)*	
For the three months ended June 30	**2011**	2010	**2011**	2010
Domestic				
Residential	**$ 346**	$ 281	**4,141**	3,629
Light industrial and commercial	**314**	302	**4,263**	4,258
Large industrial	**134**	125	**3,183**	3,124
Other energy sales	**44**	52	**224**	241
Total Domestic Revenue Before Regulatory Transfer	**838**	760	**11,811**	11,252
Domestic load variance regulatory transfer	**48**	25	**—**	—
Total Domestic	**$ 886**	$ 785	**11,811**	11,252
Trade				
Electricity – Gross	**$ 250**	$ 257	**8,238**	7,062
Less: forward electricity purchases[1]	**(71)**	(122)	**—**	—
Electricity – Net	**179**	135	**—**	—
Gas – Gross	**285**	180	**7,046**	5,167
Less: forward gas purchases[1]	**(269)**	(128)	**—**	—
Gas – Net	**16**	52	**—**	—
Total Trade	**$ 195**	$ 187	**15,284**	12,229
Total	**$ 1,081**	$ 972	**27,095**	23,481

[1] *Forward purchases include derivatives which are deducted from gross sales in accordance with generally accepted accounting principles.*

Total revenue for the three months ended June 30, 2011 was $1,081 million, an increase of $109 million compared with the same period in the prior year. Domestic revenues increased due to higher average rates in all customer classes and higher consumption by residential customers, while trade revenues increased due to higher gas and electricity trade sales volumes and higher gas prices.

Domestic Revenues

Total domestic revenues of $886 million for the first quarter of fiscal 2012 were $101 million or 13 per cent higher than in the same period in the prior year. The increase was primarily due to higher average rates, which increased effective May 1, 2011 on an interim basis by 8 per cent, while sales volumes for the quarter increased primarily due to higher consumption in the residential customer class as a result of colder weather conditions in the spring of 2011 as compared to the same period in the prior year and higher than normal usage. Variances between actual and planned load are deferred to the Non-Heritage Deferral Account (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 quarter ended June 30, 2011 increased by $98 million from fiscal 2011 due to an increase in gross gas revenue of $105 million, partially offset by a decrease in gross electricity revenue of $7 million. The increase in gas revenue was primarily driven by a 36 per cent increase in gas sales volumes, reflecting Powerex's continuing aim to grow its gas business, as well as a 15 per cent increase in the average gas sales price over the prior year. The increase in gas prices was primarily attributable to increased electrical and industrial demand. The decrease in gross electricity revenue was due to a 28 per cent decrease in the average electricity sales price driven by high Alberta prices in the prior year resulting from Alberta generation limitations, partly offset by a 17 per cent increase in electricity sales volumes. Deducted from gross trade revenue are forward purchases, which decreased by a net $90 million compared to the prior year. Forward transactions are reported on a net basis in accordance with GAAP.

OPERATING COSTS

For the three months ended June 30, 2011, total operating costs of $866 million were $91 million higher than in the same period in the prior year. The increase is primarily due to increases in the cost of energy due to higher planned trade energy costs and higher non-energy operating costs including higher amortization expense and an increase in personnel expenditures, partially offset by 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)		(Revised)		
For the three months ended June 30	**2011**	2010	**2011**	2010	**2011**[4]	2010[4]
Domestic						
Water rental payments (hydro generation)[1]	**$ 74**	$ 64	**9,778**	8,600	**$ 7.75**	$ 7.86
Purchases from Independent Power Producers	**155**	148	**2,560**	2,524	**60.46**	58.64
Other electricity purchases – Domestic	**11**	21	**556**	677	**19.80**	31.02
Gas for thermal generation	**8**	10	**29**	41	**274.22**	243.90
Transmission charges and other expenses[2]	**3**	20	**26**	25	**—**	—
Allocation to/from trade energy	**(8)**	25	**(129)**	619	**30.34**	39.38
Total Domestic Cost of Energy Before Regulatory Transfers	**243**	288	**12,820**	12,486	**$ 18.93**	$ 23.07
Domestic cost of energy regulatory transfers	**23**	(25)	**—**	—	**—**	—
Total Domestic	**$ 266**	$ 263	**12,820**	12,486	**$ 20.74**	$ 21.06
Trade						
Electricity – Gross	**$ 138**	$ 200	**7,821**	7,549	**$ 17.64**	$ 26.49
Less: forward electricity purchases[3]	**(71)**	(122)	**—**	—	**—**	—
Electricity – Net	**67**	78	**—**	—	**—**	—
Remarketed gas – Gross	**275**	171	**7,091**	5,250	**38.78**	32.57
Less: forward gas purchases[3]	**(269)**	(128)	**—**	—	**—**	—
Remarketed gas – Net	**6**	43	**—**	—	**—**	—
Transmission charges and other expenses	**52**	53	**—**	—	**—**	—
Allocation to/from domestic energy	**8**	(25)	**129**	(619)	**30.34**	39.38
Total Trade Cost of Energy Before Regulatory Transfers	**133**	149	**15,041**	12,180	**$ 13.54**	$ 46.00
Trade net margin regulatory transfers	**18**	(27)	**—**	—	**—**	—
Total Trade	**$ 151**	$ 122	**15,041**	12,180	**$ 14.70**	$ 43.75
Total Energy Costs	**$ 417**	$ 385	**27,861**	24,666	**$ 17.50**	$ 32.27

[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.

Total energy costs, after regulatory account transfers, for the first quarter of fiscal 2012 were $417 million, 8 per cent higher than the same period last year. The increase was primarily due to higher trade energy purchase costs, while domestic energy costs were comparable to the prior year.

Domestic Energy Costs

Domestic energy costs before regulatory transfers of $243 million for the three months ended June 30, 2011 were 16 per cent lower than in the same period in the prior year. The decrease was due to lower market energy purchases, lower purchases for future trade, and lower transmission charges. The British Columbia Transmission Corporation (BCTC) was integrated with BC Hydro in the second quarter of fiscal 2011 and transmission costs recognized by BC Hydro as cost of energy in the first quarter of fiscal 2011, when the two companies were separate entities, have been reclassified as other operating costs in the current year as a result of the inclusion of transmission activities in BC Hydro's operations. The above decreases were partially offset by higher water rental costs primarily due to higher hydro generation volumes as a result of higher water inflows. In addition, purchases from Independent Power Producers (IPPs) were higher due to new IPPs becoming operational, partially offset by lower gas costs from Island Generation purchases. Variances between actual and planned domestic cost of energy are transferred to the Heritage Deferral Account (HDA) and NHDA.

Trade Energy Costs

Gross trade energy costs for the quarter ended June 30, 2011 increased by $74 million from fiscal 2011 primarily due to a $104 million increase in gas purchase costs, partially offset by a $62 million decrease in electricity purchased for trade. The increase in gross gas purchases was due to a 35 per cent increase in purchased volumes, consistent with the increase in sales volumes, as well as a 19 per cent increase in the average gas purchase price. Electricity purchase costs decreased primarily due to a 33 per cent decrease in the average electricity purchase price. As with the average electricity sales price, this was primarily driven by high Alberta prices in the prior year resulting from Alberta generation limitations. Deducted from gross trade energy costs are forward purchases, which decreased by a net $90 million compared to the prior year. Forward purchases are netted against forward sales within gross revenue.

Water Inflows

Following two of the lowest water inflow years on record, system inflows for fiscal 2012 are forecast to be 102 per cent of average, with inflows to the Williston Reservoir on the Peace River system at 101 per cent and the Kinbasket Reservoir on the Columbia River system at 104 per cent of average. System inflows were 86 per cent of average in fiscal 2011 and 87 per cent of average in fiscal 2010. For the summer of 2011 (fiscal 2012), there is a relatively low risk of spill at either the Williston or Kinbasket reservoirs.

Despite below average inflows for the past two years, BC Hydro reservoirs have been managed such that the combined system storage in BC Hydro reservoirs at June 30, 2011 was 102 per cent of average, with the Williston and Kinbasket reservoirs at 99 per cent and 108 per cent of average, respectively. BC Hydro has taken advantage of low market prices and purchased energy from the market, saving the energy in its reservoirs for future needs. In comparison, combined system storage at June 30, 2010 was 85 per cent of average.

OTHER OPERATING EXPENSES

Personnel Expenses

Personnel expenses include labour, benefits and employee future benefits. Personnel costs, after net regulatory transfers, of $150 million for the three months ended June 30, 2011 were $19 million higher than in the same period in the prior year primarily due to 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 due to higher non-current pension costs.

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 $144 million were comparable to the same period in 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 months ended June 30, 2011 amortization and depreciation expense was $180 million, compared with $123 million in the same period in the prior year. The increase was 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.

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 $46 million for the quarter were comparable to the same period in the prior 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 months ended June 30, 2011 are $65 million, compared to $49 million for the same period in the prior year, in line with an increase in capital expenditures in the current quarter as compared to the first quarter of fiscal 2011.

FINANCE CHARGES

Finance charges, after net regulatory transfers, of $123 million for the first quarter of fiscal 2012 were $17 million higher than in the same period in the prior year. The increase is primarily due to higher interest on long term debt due to a higher planned volume of long-term debt issues required to fund capital additions, lower capitalized interest, higher financing lease interest expense due to an increase in planned capital lease costs, and higher interest on short-term borrowings due to higher planned interest rates.

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, finance charges and non-current pension costs; 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:

	For the three months ended June 30	
(in millions)	**2011**	2010
Variances between forecast and actual costs		
Energy deferral accounts	**$ (35)**	$ 81
Finance charges	**(4)**	(13)
Other	**(7)**	2
	(46)	70
Deferral of costs for future recovery in rates		
Demand-Side Management programs	**28**	25
Rate Smoothing	**35**	—
Other	**41**	23
	104	48
Amortization of regulatory accounts	**(45)**	1
Interest on regulatory accounts	**12**	7
Net change in regulatory accounts	**$ 25**	$ 126

For the three months ended June 30, 2011, BC Hydro transferred, on a net basis, $25 million to regulatory accounts, compared with the transfer of $126 million to the regulatory accounts during the same period last year. The majority of the transfers relate to the cost of energy deferral accounts, DSM and the Rate Smoothing Regulatory Account. The net asset balance in the regulatory asset and liability accounts as at June 30, 2011 was an asset of $2,185 million compared to $2,160 million at March 31, 2011.

The transfers to the energy deferral accounts primarily reflect higher than planned trade income resulting from favourable price spreads in the Northwest and Alberta and lower than planned domestic cost of energy as a result of high water inflows which reduced the requirement for market energy purchases and purchases for future trade, and IPP purchases made at lower than planned prices. These favourable variances were partially offset by lower than planned domestic revenues primarily due to lower than planned customer rates as the approved interim average rate increase of 8 per cent effective May 1, 2011 was lower than the planned increase of 9.73 per cent for the fiscal year, partially offset by higher consumption in the residential customer class due to cooler than expected weather. In comparison, energy deferral account transfers for the same period in fiscal 2011 reflected higher than planned domestic energy costs resulting from low water inflows and lower than planned trade income due to low price spreads.

Expenditures in the first quarter on DSM projects, which support energy conservation, were consistent with the same period in the prior year. The Rate Smoothing Regulatory Account has been applied for to smooth the rate increases applied for in BC Hydro's F2012–2014 RRA over the three year period covered by the application. This deferral account remains subject to BCUC approval. The change in amortization of regulatory accounts 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 (GBE) 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 a regulation issued by the Province's Treasury Board, 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. No dividend has been accrued as at June 30, 2011 for fiscal 2012 as BC Hydro's debt to equity ratio is over the 80:20 cap before any dividend accrual.

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 June 30, 2011, Powerex was owed US $265 million (CDN $256 million) 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 a certain return on equity (ROE). The annual rate of ROE 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 ROE in fiscal years 2010, 2011 and 2012. The allowed rate of ROE 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 return on equity is based.

OIC No. 020 dated February 2, 2011 and effective April 1, 2011 amended Heritage Special Direction No. 2, such that BC Hydro's return on equity 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 F2012-2014 RRA incorporates the changes to the return on equity calculation.

F2012–2014 RRA

BC Hydro's F2012–F2014 RRA was filed with the BCUC on March 1, 2011, requesting an average rate increase of 9.73 per cent per year in each of fiscal 2012 to fiscal 2014. These requested rate increases reflect increasing capital-related costs (amortization, financing costs and return on equity) due to higher levels of investment in assets; an increase in domestic energy costs due to purchases of higher-priced new supply; and a reduction in forecast trade income due to forecast weaker export market conditions.

On April 21, 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 F2012-F2014 RRA until the completion of a provincial government review of BC Hydro. The outcome of this review will be incorporated into an amended revenue requirements application to the BCUC, expected to be filed in the fall of 2011.

Interior to Lower Mainland Transmission (ILM) Project

The BCUC reconsidered the ILM application for the purpose of determining the adequacy of First Nations consultation on this project from 2006 up to the point when the Certificate of Public Convenience and Necessity (CPCN) was issued in August 2008. Construction on this project has been suspended, pending a decision on this matter.

The BCUC issued its decision on February 3, 2011, finding that the Crown's duty to consult with certain First Nations had not been adequately met as of August 5, 2008 and as a result is continuing the suspension of the ILM CPCN. As directed by the decision, BC Hydro conducted further consultation with the affected First Nations and filed two compliance reports in June 2011 addressing these deficiencies. On July 8, 2011 the BCUC temporarily suspended the hearing process for reviewing these reports.

Those First Nations whom the BCUC deemed had been adequately consulted with filed an application to the BCUC on March 2, 2011 seeking reconsideration of the BCUC decision. The BCUC dismissed this application on May 6, 2011 on the basis that it did not meet their threshold for a reconsideration to progress. However, on June 27, 2011 the Court of Appeal granted leave to these First Nations to appeal the BCUC reconsideration decision.

Ruskin Dam Upgrade Project

On February 22, 2011, BC Hydro filed an application for a 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 extended to accommodate the filing of First Nations evidence and is now expected to conclude in November 2011. A decision is likely in early 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. BC Hydro is seeking a written hearing process for review of this application and, on this basis, would expect a decision from the BCUC in January 2012.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the first quarter was $68 million, compared with cash flow provided by operating activities of $113 million for the same period last year. The decrease was primarily due to changes in working capital relative to the same period in the prior year.

The long-term debt balance net of sinking funds at June 30, 2011 was $12.3 billion, compared with $11.5 billion at March 31, 2011. The increase was mainly a result of net long-term bond issues totaling $979 million ($1 billion par value). This increase was partially offset by a decrease in revolving borrowings of $218 million, net foreign exchange revaluation gains on bonds and sinking funds of $8 million, a decrease of $3 million in debt due to fair value hedge accounting, amortization of premiums of $2 million and sinking fund income of $1 million. The net increase in borrowings was due to the funding of capital expenditures and the Payment to the Province of the fiscal 2011 dividend.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

	For the three months ended June 30	
(in millions)	**2011**	2010
Distribution improvements and expansion	**$ 93**	$ 88
Generation replacements and expansion	**117**	95
Transmission lines and substation replacements & expansion	**105**	84
General, including computers and vehicles	**82**	50
	$ 397	$ 317

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.

Generation capital expenditures increased by $22 million in the first quarter compared with the same period in the prior year. The increase is mainly due to higher spending in fiscal 2012 on the Fort Nelson Resource Smart Upgrade, Mica Units 5 & 6 Installation and the Bridge River Townsite Redevelopment, partially offset by lower spending on the Mica Gas Insulated Switchgear Replacement and the Revelstoke Unit 5 Installation, as it was placed in service in the third quarter of fiscal 2011.

Transmission lines and substations capital expenditures increased by $21 million in the first quarter compared with the same period in the prior year. The increase is mainly due to higher spending in fiscal 2012 on the Northwest Transmission Line, Vancouver City Central Transmission Project and the Columbia Valley Transmission Project, partially offset by lower spending on the Central Vancouver Island Project which was substantially complete at the end of fiscal 2011.

General capital expenditures increased by $32 million in the first quarter compared with the same period in the prior year. The increase is mainly due to higher spending on the Smart Metering and Infrastructure Program and timing of vehicle purchases; partially offset by higher expenditures in the first quarter of fiscal 2011 due to the purchase of the Edmonds Annex Building.

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 mitigate them to levels which are commensurate with the potential benefits to be derived. 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 responsible for facilitating this risk management process and promoting strong oversight of significant risks by the BC Hydro Risk Management Committee. 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.

The generation, transmission and distribution of electricity inherently results in certain safety risks to both BC Hydro workers and the public. To manage worker and public safety, BC Hydro relies on education and training, safe design, barrier installation, safe work procedures, safety practice regulations and communication. BC Hydro also prepares emergency response plans to limit injury and loss to life and to restore electric service. The large dams represent a catastrophic loss risk (low probability but high consequence) in terms of life, safety, financial, environmental and reputation. This dam failure risk is managed through a comprehensive dam safety management system involving dam safety professionals and experts.

Significant risks to the reliability of BC Hydro's system include aging infrastructure and the impact of weather. Reliability risks could also result from either a lack of available generation supply or the associated transmission capacity to meet customer demand. BC Hydro manages these risks through long-term planning, asset maintenance and replacement programs, emergency response programs, a diverse supply of energy options, and through cooperative support arrangements with neighbouring utilities.

System inflows, market prices, and domestic load influence cost of energy. The system inflow energy for fiscal 2012 is now expected to be slightly above normal and the system is forecast to be in a modest net sales position for fiscal 2012. Several factors constrain BC Hydro'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 volatile, particularly due to large industrial customers who may curtail or expand their operations due to the state of export markets and world commodity prices. BC Hydro's risk mitigation strategy is to achieve energy security and price certainty by developing adequate domestic electricity supplies, and through energy conservation and efficiency. BC Hydro 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.

Legal and regulatory requirements for First Nation consultation, claims of historic grievances, land claims, and service reliability issues pose risks to BC Hydro. These risks are managed through a comprehensive aboriginal relations program. Building mutually-beneficial relationships with First Nations reduces financial, legal, regulatory and operating risks.

In meeting its financial performance targets, BC Hydro faces many risks including uncertain economic conditions, variable costs and revenues as driven by energy costs, energy demand, interest and foreign exchange rates, pension obligations and energy trading. Of these, risks associated with energy costs—specifically water inflows and energy market prices—are the largest. Tariff rates are set based upon BC Hydro's cost forecast and allowed return on deemed equity. Many financial risks (differences between forecast and actual costs) associated with uncontrollable costs are mitigated through regulatory accounts. Increasing costs due to aging infrastructure, the modernization and refurbishment of the electricity system, the need for new supply and the need to manage environmental impacts create challenges for BC Hydro in maintaining rates that meet customer expectations.

BC Hydro's energy trading subsidiary, Powerex, is exposed to the risk of variable market prices and counterparties who might not meet their obligations. Powerex manages these risks by operating through defined limits that are regularly reviewed by both the Powerex and BC Hydro Boards of Directors.

The slow economic recovery has stabilized the labour supply of engineers and senior managers and has also improved BC Hydro's ability to attract and retain staff in a variety of roles. In addition, apprentice and trainee programs have increased BC Hydro's pipeline for incumbents into trades and technical roles, as the external market can often have a limited supply of individuals with these qualifications. BC Hydro has continued to experience a delay in employee retirements; however this may result in a sudden surge of retirements in the future with shorter notice periods. Apprentice programs and contingent workers partially mitigate this risk. In addition, the return on pension fund assets and the market discount rate at year end can have a significant impact on the cost of providing employee future benefits.

Areas where BC Hydro is exposed to the risk of non-compliance with environmental regulations include the release of hazardous materials into the environment and endangerment of wildlife and their habitats. These risks are managed through a variety of site specific risk management strategies.

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 2011 forecasts net income for fiscal 2012 at $611 million. The Service Plan assumes a 9.73 per cent interim rate increase for fiscal 2012.

On March 1, 2011, BC Hydro filed its F2012-F2014 RRA with the BCUC, seeking approval for rate increases of 9.73 per cent for each of the next three years reflecting increasing capital-related costs, an increase in domestic energy costs and a reduction in forecast trade income. On April 21, 2011, the BCUC approved an interim rate increase of 8 per cent effective May 1, 2011 and suspended the regulatory review of the F2012-2014 RRA until the completion of a provincial government review of BC Hydro. The outcome of this review, along with changes in key assumptions, will be incorporated into an amended BC Hydro revenue requirements application to the BCUC, expected to be filed in the fall of 2011.

The amended BC Hydro revenue requirement application is expected to seek an average 5.9 per cent per year rate increase for the fiscal 2012 to fiscal 2014 period which may be achieved through different rate increase options over the three years. The reduction from the 9.73 per cent increase per year from the original application will be achieved through a combination of reductions in operating costs and capital additions, deferral of work programs to future years, and the use of regulatory accounts to mitigate the impact on rates in the fiscal 2012 to fiscal 2014 period.

BC Hydro's results 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 impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The updated forecast assumes average water inflows for fiscal 2012, customer load of 52,919 GWh, average market energy prices of CDN $27.75/MWh, and an allowed return on equity of 14.38 per cent.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) JUNE 30, 2011

CONSOLIDATED STATEMENTS OF OPERATIONS

(unaudited)	*For the three months ended June 30*	
		(Revised Note 1)
(in millions)	**2011**	2010
Revenues		
Domestic	**$ 886**	$ 785
Trade	**195**	187
	1,081	972
Expenses		
Operating Costs		
Cost of energy (Note 9)	**417**	385
Other operating expenses (Note 9)	**449**	390
	866	775
Finance Charges	**123**	106
	989	881
Net Income	**$ 92**	$ 91

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited)	*For the three months ended June 30*	
(in millions)	**2011**	2010
Net Income	**$ 92**	$ 91
Other Comprehensive Loss (Note 8)	**(3)**	(18)
Comprehensive Income	**$ 89**	$ 73

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(unaudited)	*For the three months ended June 30*	
(in millions)	**2011**	2010
Retained Earnings, Beginning of Period	**$ 2,747**	$ 2,621
Net Income	**92**	91
Retained Earnings, End of Period	**$ 2,839**	$ 2,712

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

(unaudited) *(in millions)*	As at June 30 2011	As at March 31 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 7	$ 27
Accounts receivable and accrued revenue	568	569
Inventories	151	128
Prepaid expenses	196	156
Current portion of derivative financial instrument assets	157	198
	1,079	1,078
Other Assets		
Property, plant and equipment	15,436	15,211
Intangible assets	349	335
Regulatory assets (Note 4)	2,465	2,436
Sinking funds	97	97
Employee future benefits	286	296
Derivative financial instrument assets	21	26
	18,654	18,401
	$ 19,733	$ 19,479
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$ 945	$ 1,515
Current portion of long-term debt	2,573	2,793
Current portion of derivative financial instrument liabilities	123	159
	3,641	4,467
Other Liabilities		
Long-term debt (Note 5)	9,819	8,851
Regulatory liabilities (Note 4)	280	276
Deferred contributions	1,032	1,012
Derivative financial instrument liabilities, long-term	213	212
Other long-term liabilities	1,779	1,781
	13,123	12,132
Shareholder's Equity		
Contributed surplus	60	60
Retained earnings	2,839	2,747
Accumulated other comprehensive income (Note 8)	70	73
	2,969	2,880
	$ 19,733	$ 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 & Risk Management Committee

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	*For the three months ended June 30*	
(in millions)	**2011**	2010
Operating Activities		
Net income	**$ 92**	$ 91
Regulatory account transfers	**(68)**	(120)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 4)	**45**	(1)
Amortization expense and depreciation	**140**	109
Foreign exchange translation (gains) losses	**(1)**	6
Unrealized gains on mark-to-market	**—**	(30)
Employee benefit plan expenses	**16**	12
Other items	**(3)**	9
	221	76
Changes in non-cash working capital:		
Accounts receivable and accrued revenue	**1**	71
Accounts payable and accrued liabilities	**(91)**	(28)
Prepaid expenses	**(40)**	39
Inventories	**(23)**	(45)
	(153)	37
Cash provided by operating activities	**68**	113
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(412)**	(367)
Deferred contributions	**27**	12
Other items	**4**	(1)
Cash used in investing activities	**(381)**	(356)
Financing Activities		
Long-term debt		
Issued	**987**	—
Revolving borrowings, included in long-term debt	**(218)**	327
Debt issue and related costs	**(7)**	—
Payment to the Province	**(463)**	(47)
Repayment of capital lease liability	**(6)**	—
Cash provided by financing activities	**293**	280
Increase (decrease) in cash and cash equivalents	**(20)**	37
Cash and cash equivalents, beginning of period	**27**	9
Cash and cash equivalents, end of period	**$ 7**	$ 46
Supplemental Disclosure of Cash Flow Information		
Interest paid	**$ 189**	$ 168
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) JUNE 30, 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. BC Hydro is subject to regulation (see Note 4) by the British Columbia Utilities Commission (BCUC) which, among other things, approves the rates BC Hydro charges for its services.

NOTE 1: ACCOUNTING POLICIES

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. 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. 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.

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 continued uncertainty around the timing and adoption of a 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.

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's statements related to revenues, cost of energy, and finance charges have been reclassified to conform to the current year's presentation.

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, 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: FUTURE ACCOUNTING CHANGE

Subsequent to the one-year deferral for adopting IFRS, BC Hydro will adopt financial reporting provisions prescribed by the Province. 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 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 and approved with 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 F2012–F2014 Revenue Requirements Application (RRA) was filed with the BCUC on March 1, 2011, requesting an average rate increase of 9.73 per cent per year in each of fiscal 2012 to fiscal 2014. These requested rate increases reflect increasing capital-related costs (amortization, financing costs and return on equity) due to higher levels of investment in assets; an increase in domestic energy costs due to purchases of higher-priced new supply; and a reduction in forecast trade income due to forecast weaker export market conditions.

On April 21, 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 F2012-F2014 RRA until the completion of a provincial government review of BC Hydro. The outcome of this review will be incorporated into an amended revenue requirements application to the BCUC, expected to be filed in the fall of 2011.

Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. For the three months ended June 30, 2011, the impact of regulatory accounting has resulted in an increase to net income of $25 million (2010—$126 million increase).

(in millions)	April 1 2011	Addition (Reduction)	Amortization	Net Change	June 30 2011
Regulatory Assets					
Heritage Deferral Account	$ 247	$ (4)	$ (6)	$ (10)	$ 237
Non-Heritage Deferral Account	362	(2)	(9)	(11)	351
Trade Income Deferral Account	188	(19)	(5)	(24)	164
Demand-Side Management Programs	506	28	(19)	9	515
First Nation Negotiations, Litigation and Settlement Costs	399	5	(2)	3	402
Non-Current Pension Cost	72	(2)	(5)	(7)	65
Site C	104	18	—	18	122
Environmental Compliance	231	2	(1)	1	232
Other Regulatory Accounts	327	53	(3)	50	377
Total Regulatory Assets	2,436	79	(50)	29	2,465
Regulatory Liabilities					
Future Removal and Site Restoration Costs	140	—	(5)	(5)	135
Foreign Exchange Gains and Losses	106	1	—	1	107
Finance Charges	4	4	—	4	8
Other Regulatory Accounts	26	4	—	4	30
Total Regulatory Liabilities	276	9	(5)	4	280
Net Regulatory Asset	$ 2,160	$ 70	$ (45)	$ 25	$ 2,185

Orders in Council (OIC) 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. OIC No. 020 dated February 2, 2011 and effective April 1, 2011 amended Heritage Special Direction No. 2, such that BC Hydro's return on equity 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 F2012-2014 RRA incorporates the changes to the return on equity calculation.

On April 29, 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 on May 19, 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.

In July 2011, BC Hydro received approval for deferral of fiscal 2011 costs for the Smart Metering and Infrastructure (SMI) Project, which were $15 million (asset) as at March 31, 2011.

BC Hydro applied for the establishment of the F2012-F2014 Rate Smoothing regulatory account in order to smooth out the rate increases proposed in the F2012-F2014 RRA, which was $35 million (asset) as at June 30, 2011.

Other regulatory asset accounts with individual balances less than $65 million include the following: Contributions in Aid of Construction Amortization Variance, Capital Project Investigation Costs, Procurement Enhancement Initiative Costs, SMI, 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

During the three month period ended June 30, 2011, the Company issued bonds with a par value of $1 billion, a weighted average effective interest rate of 4.42 per cent and a weighted average term to maturity of 31.1 years. Debt issue costs associated with the transactions was $7 million.

NOTE 6: CAPITAL MANAGEMENT

Orders in Council 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 imposed requirement of maintaining a debt to equity ratio not exceeding 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 so as not to exceed the 80:20 debt to equity ratio as defined by the Province. During the period, there were no changes in this approach to capital management.

The debt to equity ratio at June 30, 2011 and March 31, 2011 was as follows:

(in millions)	**As at June 30 2011**	As at March 31 2010
Total long-term debt, net of sinking funds	**$ 12,295**	$ 11,547
Less: cash and cash equivalents	**(7)**	(27)
Net Debt	**$ 12,288**	$ 11,520
Retained earnings	**$ 2,839**	$ 2,747
Contributed surplus	**60**	60
Accumulated other comprehensive income	**70**	73
Total Equity	**$ 2,969**	$ 2,880
Net Debt to Equity Ratio	**81 : 19**	80 : 20

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. No dividend has been accrued as at June 30, 2011, as BC Hydro's debt to equity ratio is over 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 new income earned by BC Hydro and its subsidiaries from all sources as reflected in the consolidated audited financial staements, 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 months ended June 30, 2011 was $31 million (2010—$26 million).

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

Other Comprehensive Income (Loss)

	For the three months ended June 30	
(in millions)	**2011**	2010
Other Comprehensive Income (Loss)		
Unrealized (loss) gain on derivatives designated as cash flow hedges	**$ (11)**	$ 26
Reclassification to income of gain (loss) on deriviatives designated as cash flow hedges	**8**	(44)
Other Comprehensive Loss	**$ (3)**	$ (18)

Accumulated Other Comprehensive Income

	For the three months ended June 30	
(in millions)	**2011**	2010
Accumulated other comprehensive income, beginning of period	**$ 73**	$ 53
Other comprehensive loss for the period	**(3)**	(18)
Accumulated Other Comprehensive Income, End of Period	**$ 70**	$ 35

NOTE 9: OPERATING COSTS

Cost of Energy

(in millions)	*For the three months ended June 30* 2011	2010
Electricity and gas purchases	**$ 316**	$ 239
Water rentals	**71**	71
Transmission charges	**30**	75
Cost of Energy	**$ 417**	$ 385

Other Operating Expenses

(in millions)	*For the three months ended June 30* 2011	2010
Personnel expenses	**$ 150**	$ 131
Materials and external services	**144**	144
Amortization and depreciation	**180**	123
Grants and taxes	**46**	45
Capitalized costs	**(65)**	(49)
Other costs	**(6)**	(4)
Other Operating Costs	**$ 449**	$ 390

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 refunds, 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 June 30, 2011, Powerex was owed US $265 million (CDN $256 million) 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.

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