BC HYDRO FIRST QUARTER REPORT FISCAL 2014

BC hydro
FOR GENERATIONS

BRITISH COLUMBIA

BC HYDRO & POWER AUTHORITY MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the three months ended June 30, 2013 and should be read in conjunction with the MD&A presented in the 2013 Annual Report, the 2013 Annual Consolidated Financial Statements of the Company, and the Unaudited Condensed Consolidated Interim Financial Statements and related notes of the Company for the three months ended June 30, 2013.

The Company applies accounting standards as prescribed by the Province of British Columbia ("the Province") which applies the accounting principles of International Financial Reporting Standards (IFRS) except that the Company applies regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* (ASC 980) ("Prescribed Standards"). All financial information is expressed in Canadian dollars unless otherwise specified.

This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of the Company. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward-looking statements.

HIGHLIGHTS

- Net income after regulatory transfers for the three months ended June 30, 2013 was $55 million, comparable to $53 million in the same period in the prior fiscal year, as higher domestic and trade prices were offset by lower load and higher amortization and depreciation due to higher assets in service and higher regulatory account amortization.
- On August 15, 2013, the Company's subsidiary Powerex entered into a settlement agreement subject to the Federal Energy Regulatory Commission (FERC) approval with the California parties involved in the various ongoing legal claims to resolve all outstanding litigation and claims filed against it arising from events and transactions in the California power market during the 2000 and 2001 period. As part of the settlement, Powerex made a net cash payment into escrow of US$273 million. This was accounted for as an adjusting subsequent event and an expense of CDN$214 million was recorded as of June 30, 2013. The Province has advised BC Hydro that it intends to issue a direction or regulation in the fall of 2013 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget. As a result, the loss was deferred to the Trade Income Deferral Account (TIDA).
- The observed system inflow energy equivalent for the three months ended June 30, 2013 was 103 per cent of average, with inflows to the Williston Reservoir at 98 per cent and the Kinbasket Reservoir at 114 per cent of average. The forecast system inflow energy equivalent for fiscal 2014 is 100 per cent, with Williston Reservoir at 93 per cent and Kinbasket Reservoir at 106 per cent. The system inflow energy equivalent was 109 per cent of average in fiscal 2013, but actual inflows were higher because both Williston and Kinbasket reservoirs spilled substantial volumes of surplus water and in addition, the system was managed with significant economic spill due to very low market prices. In contrast, fiscal 2014 is shaping up to have near average inflows and higher market prices.
- Capital expenditures for the three months ended June 30, 2013 were $402 million, as BC Hydro continues to invest significantly to refurbish its ageing infrastructure and build new assets for future growth, including Mica Units 5 & 6 Project, G.M. Shrum Units 1 to 5 Turbine Rehabilitation, Ruskin Dam and Powerhouse Upgrade, Smart Metering and Infrastructure (SMI), Northwest Transmission Line Project, Interior to Lower Mainland Transmission Project, and Vancouver City Central Transmission Project.

(in millions)	For the three months ended June 30 2013	2012	Change
Net Income	**$ 55**	$ 53	$ 2
Number of Domestic Customers	**1,896,896**	1,877,343	19,553
GWh Sold (Domestic)	**11,977**	13,454	(1,477)
Total Reservoir Storage (GWh)	**24,848**	26,620	(1,772)

(in millions)	**As at June 30, 2013**	As at March 31, 2013	Change
Total Assets	**$ 24,216**	$ 23,782	$ 434
Retained Earnings	**$ 3,424**	$ 3,369	$ 55
Debt to Equity	**80 : 20**	80 : 20	N/A

CONSOLIDATED RESULTS OF OPERATIONS

These interim statements represent the Company's presentation of its results and financial position under the Prescribed Standards. Under the Prescribed Standards, the Company applies the principles of IFRS plus ASC 980 to reflect the rate-regulated environment in which the Company operates. These principles allow for the deferral of costs and recoveries that under IFRS would otherwise be recorded as expenses or income in the current accounting period. The deferred amounts are either recovered or refunded through future rate adjustments.

The use of regulatory accounts is common amongst regulated utility industries throughout North America. BC Hydro uses various regulatory accounts, in compliance with British Columbia Utilities Commission (BCUC) orders, in order to better match costs and benefits for different generations of customers, smooth out the rate impact of large non-recurring costs, and defer to future periods differences between forecast and actual costs or revenues.

For the three months ended June 30, 2013, net transfers resulted in a net addition to regulatory accounts of $239 million, primarily due to the California litigation settlement discussed above. Other increases included deferral of costs for future recovery in rates including demand-side management programs (DSM), Site C and SMI, and the phasing in of the rate impact of the reduction in the amount of overhead eligible for capitalization under IFRS as compared to Canadian generally accepted accounting principles (CGAAP).

Net income after regulatory transfers for the three months ended June 30, 2013 was $55 million, comparable to $53 million in the same period in the prior fiscal year, as higher domestic and trade prices were offset by lower load and higher amortization and depreciation due to higher assets in service and higher regulatory account amortization.

REVENUES

Total revenue for the three months ended June 30, 2013 was $1,254 million, an increase of $196 million or 19 per cent compared to the same period in the prior fiscal year primarily due to higher trade revenues resulting primarily from higher trade electricity and gas prices, partially offset by lower gigawatt hours sold.

	(in millions)		(gigawatt hours)	
For the three months ended June 30	**2013**[1]	2012[1]	**2013**	2012
Domestic				
Residential	**$ 341**	$ 332	**3,765**	3,696
Light industrial and commercial	**355**	344	**4,407**	4,333
Large industrial	**158**	154	**3,319**	3,343
Other energy sales	**56**	59	**486**	2,082
Total Domestic Revenue Before Regulatory Transfer	**910**	889	**11,977**	13,454
Rate smoothing and load variance regulatory transfer	**37**	5	**–**	–
Total Domestic	**$ 947**	$ 894	**11,977**	13,454
Trade				
Electricity – Gross	**$ 337**	$ 188	**8,328**	10,109
Less: forward electricity purchases[2]	**(71)**	(40)	**–**	–
Electricity – Net	**266**	148	**–**	–
Gas – Gross	**204**	113	**5,025**	6,258
Less: forward gas purchases[2]	**(163)**	(97)	**–**	–
Gas – Net	**41**	16	**–**	–
Total Trade	**$ 307**	$ 164	**13,353**	16,367
Total	**$ 1,254**	$ 1,058	**25,330**	29,821

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

DOMESTIC REVENUES

Total domestic revenues after regulatory transfers for the three months ended June 30, 2013 were $947 million, an increase of $53 million or six per cent over the same period in the prior fiscal year. Domestic revenues before regulatory transfers of $910 million were $21 million or two per cent higher than in the same period in the prior fiscal year. The increase was primarily due to higher average customer rates and increased consumption by residential and light industrial and commercial customer classes due to increased economic activity, partially offset by the impact of warmer weather on residential consumption in the current period.

Average customer rates are higher in fiscal 2014 compared to the prior year, reflecting an average rate increase as approved by the BCUC of 1.44 per cent.

Other energy sales of $56 million were comparable to the same period in the prior year of $59 million as significantly lower volumes of 486 GWh in the current year compared to 2,082 GWh in the same period in the prior year were largely offset by significantly higher prices in the current year. Extremely high water in-flows in the prior year resulted in higher volumes of surplus sales but at significantly lower prices. Surplus energy sales were 255 GWh in the current period compared to 1,858 GWh in the same period of the prior year.

Variances between actual and planned load are deferred to the Non-Heritage Deferral Account (NHDA) and variances between actual and planned other energy sales are deferred to both the Heritage Deferral Account (HDA) and NHDA.

TRADE REVENUES

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

The Company's electricity system is interconnected with systems in Alberta and the Western United States, facilitating sales and purchases of electricity outside of British Columbia. Powerex's trade activities help the Company balance its system by being able to import energy to meet domestic demand when there is a supply shortage and exporting energy when there is a supply surplus. Exports are made only after ensuring domestic demand requirements can be met.

Gross trade revenue for the three months ended June 30, 2013 was $541 million, an increase of $240 million compared with the same period in the prior year due to an increase in gross electricity revenue of $149 million and an increase in gross gas revenue of $91 million. The increase in gross electricity revenue was primarily due to very low market prices in the Pacific Northwest in the prior year as a result of high water levels. This was partially offset by an 18 per cent reduction in gigawatt hours sold over the same period in the prior year. The increase in gross gas revenue was primarily driven by an 87 per cent increase in the average gas price reflecting increases in natural gas prices in North America partially offset by a 20 per cent decrease in gigawatt hours sold. Deducted from gross trade revenues are forward purchases, which decreased gross trade revenues by $234 million, a $97 million increase over the same period in the prior year, primarily due to an increase in electricity and natural gas prices. Forward transactions are reported on a net basis in accordance with the Prescribed Standards. Variances between actual and planned trade income (which includes trade revenues) are deferred to the TIDA.

OPERATING EXPENSES

For the three months ended June 30, 2013, total operating expenses of $1,051 million were $177 million higher than in the same period in the prior fiscal year. The increase was primarily the result of higher expenditures on electricity and gas purchases of $153 million consistent with higher electricity and gas sales, and higher amortization and depreciation expense of $14 million compared to the same period of the prior year due primarily to higher assets in service and higher regulatory account amortization.

COST OF ENERGY

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and transmission and other charges. Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand, and environmental and social impacts.

Total energy costs, after regulatory account transfers, for the three months ended June 30, 2013 were $531 million, $160 million or 43 per cent higher than in the prior fiscal year. The increase over the prior year was due primarily to higher trade energy purchases as current year prices increased to normal levels after unusually low average electricity and gas prices in the prior year due to the abundance of surplus energy from extremely high water inflows. The increase was partially offset by lower volumes in the current year.

For the three months ended June 30	(in millions) 2013	2012	(gigawatt hours) 2013	2012	($ per MWh) 2013[3]	2012[3]
Domestic						
Water rental payments (hydro generation)[1]	$ 96	$ 85	9,578	11,600	$ 10.41	7.44
Purchases from Independent Power Producers	198	187	2,939	2,794	67.51	66.81
Other electricity purchases - Domestic	1	1	43	37	30.90	18.78
Gas for thermal generation	10	7	39	23	251.17	283.84
Transmission charges and other expenses	2	(33)	25	25	–	–
Allocation to/from trade energy	10	3	426	87	24.30	14.61
Total Domestic Cost of Energy Before Regulatory Transfers	317	250	13,050	14,566	24.30	17.14
Domestic cost of energy regulatory transfers	(49)	8	–	–	–	–
Total Domestic	$ 268	$ 258	13,050	14,566	$ 20.53	$ 17.70
Trade						
Electricity - Gross	$ 207	$ 75	8,687	10,074	$ 23.83	$ 7.44
Less: forward electricity purchases[2]	(71)	(40)	–	–	–	–
Electricity - Net	136	35	–	–	–	–
Remarketed gas - Gross	191	118	5,055	6,360	37.78	18.55
Less: forward gas purchases[2]	(163)	(97)	–	–	–	–
Remarketed gas - Net	28	21	–	–	–	–
Transmission charges and other expenses	63	63	–	–	–	–
Allocation to/from domestic energy	(10)	(3)	(426)	(87)	24.30	14.61
Total Trade Cost of Energy Before Regulatory Transfers	217	116	13,316	16,347	21.13	11.41
Trade net margin regulatory transfer	46	(3)	–	–	–	–
Total Trade	$ 263	$ 113	13,316	16,347	$ 24.59	$ 11.24
Total Energy Costs	$ 531	$ 371	26,366	30,913	$ 22.58	$ 14.28

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

Domestic Energy Costs

Domestic energy costs after regulatory transfers for the three months ended June 30, 2013 were $268 million, $10 million or four per cent higher than the same period in the prior year. Domestic energy costs before regulatory transfers of $317 million for the three months June 30, 2013 were $67 million or 27 per cent higher than in the same period in the prior year primarily due to water transactions with Bonneville Power Administration (BPA) related to the Non-Treaty storage at Mica, higher purchases from Independent Power Producers (IPPs), higher water rental payments, and higher allocation from Trade energy.

The Company has an agreement with BPA to operate Non-Treaty storage at Mica. Under the agreement, when the Company releases water from its portion of non-treaty storage it is entitled to the value of additional energy flowing through the U.S. Federal Columbia River, as determined by the market price of energy at that time. As a result of renegotiation of the agreement in April 2012, as of June 30, 2012, the Company was entitled to $32 million for net releases from September 1, 2011 to June 30, 2012, which were reflected as a reduction to the cost of energy. For the current fiscal year, as of June 30, 2013, there were no water transactions.

Higher IPP purchases were primarily due to new IPPs achieving commercial operations during the quarter at higher contracted rates. Water rental charges are payable based on prior year's generation.

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

Trade Energy Costs

Gross trade energy costs for the three months ended June 30, 2013 were $451 million, an increase of $198 million compared with the same period in the prior year primarily due to a $132 million increase in gross trade electricity purchases and a $73 million increase in gross gas purchase costs. Trade electricity purchase costs increased due to a 220 per cent increase in the average electricity purchase price over the same period in the prior year, primarily due to very low market prices in the Pacific Northwest in the prior year as a result of high water levels. This was partially offset by a 14 per cent decrease in gigawatt hours purchased over the same period in the prior year. The increase in gross gas purchases was due to a 104 per cent increase in the average gas price, consistent with the increase in the gross gas revenue. Deducted from gross trade costs are forward purchases, which decreased gross trade costs by $234 million, an increase of $97 million compared with the same period in the prior year, primarily due to an increase in electricity and natural gas prices. Forward purchases are netted against forward sales within gross revenue in accordance with the Prescribed Standards. Variances between actual and planned trade income (which includes trade energy costs) are deferred to the TIDA.

Water Inflows

The observed system inflow energy equivalent for the three months ended June 30, 2013 was 103 per cent of average, with inflows to the Williston Reservoir at 98 per cent and the Kinbasket Reservoir at 114 per cent of average. The forecast system inflow energy equivalent for fiscal 2014 is 100 per cent, with Williston Reservoir at 93 per cent and Kinbasket Reservoir at 106 per cent. The system inflow energy equivalent was 109 per cent of average in fiscal 2013, but actual inflows were higher because both Williston and Kinbasket reservoirs spilled substantial volumes of surplus water and in addition, the system was managed with significant economic spill due to very low market prices. In contrast, fiscal 2014 is shaping up to have near average inflows and higher market prices.

BC Hydro reservoirs have been managed such that the BC Hydro system storage on June 30, 2013 was 22,700 GWh, or 600 GWh above the 10 year historic average, with the Williston and Kinbasket Reservoirs at 15,500 (100 GWh above the 10 year historic average) and 7,200 GWh (500 GWh above the 10 year historic average) respectively.

PERSONNEL EXPENSES

Personnel expenses include labour, benefits and post-employment benefits. Personnel costs of $140 million for the three months ended June 30, 2013 were comparable to $137 million for same period in the prior fiscal year.

MATERIALS AND EXTERNAL SERVICES

Expenditures on materials and external services for the three months ended June 30, 2013 of $141 million were comparable to $145 million for the same period in the prior fiscal year.

CAPITALIZED COSTS

Capitalized costs are overhead costs incurred to support capital expenditures and are transferred from operating costs to property, plant and equipment. The Prescribed Standards are different than CGAAP and only allow direct overhead costs to be capitalized to property, plant and equipment, with the effect that under the Prescribed Standards there is a decrease in property, plant and equipment and a corresponding increase in operating costs. Capitalized Costs for the three months ended June 30, 2013 of $58 million were comparable to $62 million for the same period in the prior fiscal year.

AMORTIZATION AND DEPRECIATION

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, and the amortization of certain regulatory assets and liabilities. For the three months ended June 30, 2013, amortization and depreciation expense was $244 million, $14 million or six per cent higher than the same period in the prior fiscal year. The increase was primarily due to higher assets in service in the current year.

GRANTS AND TAXES

As a Crown Corporation, the Company is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts, and school tax to the Province on certain assets. Total grants and taxes for the three months ended June 30, 2013 were $51 million, comparable with $48 million in the same period in the prior fiscal year.

OTHER COSTS (RECOVERIES)

Other costs (recoveries) primarily include gains and losses on the disposal of assets and certain cost recoveries classified as operating costs. For the three months ended June 30, 2013, other costs net of recoveries were $2 million, comparable with $5 million in the same period in the prior fiscal year.

FINANCE CHARGES

Finance charges after net regulatory transfers for the three months ended June 30, 2013 of $148 million were $17 million or 13 per cent higher than in the same period in the prior fiscal year. The increase is primarily due to higher planned volume of debt issues and revolving borrowings, higher planned short term interest rates and higher planned lease charges. The increase was partially offset by higher planned capitalized interest during construction and lower planned long term interest rates in the current year compared to the prior year.

REGULATORY ACCOUNT TRANSFERS

The Company has established various regulatory accounts with the approval of the BCUC. Regulatory accounts allow the Company to defer certain types of revenue and cost variances through transfers to and from the accounts which have the effect of adjusting net income. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC. Net regulatory account transfers are comprised of the following:

	For the three months ended June 30	
(in millions)	**2013**	2012
Energy Accounts		
Heritage Deferral	**$ 9**	$ (35)
Non-Heritage Deferral	**28**	32
Trade Income Deferral	**166**	(2)
	203	(5)
Forecast Variance Accounts		
Finance Charges	**(23)**	(6)
Rate Smoothing Account	**25**	(9)
Other	**(3)**	(5)
	(1)	(20)
Capital-Like Accounts		
Demand Side Management (DSM)	**21**	28
Site C	**13**	15
Smart Metering and Infrastructure (SMI)	**20**	19
IFRS Property, Plant and Equipment	**45**	49
	99	111
Non-Cash Accounts		
Environmental Provisions	**(12)**	26
First Nations	**10**	5
Other	**1**	2
	(1)	33
Amortization of regulatory accounts	**(71)**	(74)
Interest on regulatory accounts	**10**	12
Net change in regulatory accounts	**$ 239**	$ 57

For the three months ended June 30, 2013, net increases to the Company's regulatory accounts were $239 million, including cost additions of $300 million, interest of $10 million, partially offset by amortization of $71 million. The net asset balance in the regulatory asset and liability accounts as at June 30, 2013 was an asset of $4,673 million compared to an asset of $4,434 million as at March 31, 2013.

Additions to the regulatory accounts during the three months ended June 30, 2013 included:

- Increases to the energy deferral accounts primarily due to the California litigation settlement;
- Planned expenditures on DSM projects, which support energy conservation, Site C project and SMI;
- Transfers to the IFRS Property, Plant and Equipment regulatory account for smoothing the rate impact of overhead costs eligible for capitalization under CGAAP but not eligible under IFRS as they are not considered directly attributable to the construction of capital assets.

These additions were partially offset by decreases in the regulatory accounts during the period including:

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

PAYMENT TO THE PROVINCE

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

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. The Federal Energy Regulatory Commission (FERC) has concluded that because of a dysfunctional energy market in California between October 2000 and June 2001, certain market-wide refunds will have to be paid by energy providers, including Powerex, to various California parties.

CALIFORNIA SETTLEMENT

On August 15, 2013, Powerex entered into a settlement agreement subject to FERC approval with Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, the California Attorney General, and the California Public Utilities Commission to resolve all outstanding litigation and claims filed against it arising from events and transactions in the California power market during the 2000 and 2001 period. As part of the settlement, Powerex made a net cash payment into escrow of US$273 million. The net cash payment was calculated as the difference between the agreed upon settlement amount of US$750 million and the receivables and interest owing from the California parties to Powerex of US$477 million. This was accounted for as an adjusting subsequent event and an expense of CDN$214 million was recorded as of June 30, 2013. The expense was calculated as the net cash settlement amount of CDN$287 million (US$273 million) less amounts previously accrued related to legal claims of CDN$73 million. The Province has advised BC Hydro that it intends to issue a direction or regulation in the fall of 2013 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget. As a result, the loss was deferred to the TIDA.

RATE REGULATION

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy and achieve an annual rate of return on deemed equity (ROE). The annual rate of return is equal to the pre-income tax annual rate of return allowed by the BCUC to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*. This is in accordance with Heritage Special Direction No. HC2. The allowed rate of return for fiscal 2014 is 11.84 per cent, and is higher than the prior year's allowed rate of 11.73 per cent due to a change in the FortisBC Energy Inc. tax rate.

During April 2013, the British Columbia Utilities Commission (BCUC) issued the Generic Cost of Capital (GCOC) decision which resulted in a reduction in the Benchmark Utility Return on Equity from 9.5 per cent to 8.75 per cent which would result in a decrease to the BC Hydro allowed rate of return (ROE) for fiscal 2014 from 11.84 per cent to 10.61 per cent. However, the Province has advised BC Hydro that it intends to issue a direction or regulation in the fall of 2013 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget. Had the impact of the GCOC decision been reflected in the quarter ended June 30, 2013, the Non-Heritage Deferral Account, and consequently net income, would have been approximately $12.5 million lower than recorded.

DAWSON CREEK/CHETWYND AREA TRANSMISSION UPGRADE PROJECT

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

INDUSTRIAL ELECTRICITY POLICY REVIEW

Following a commitment to launch a public process on the retail access provisions of the Transmission Service Rate for industrial electricity customers made in late 2011, the Province subsequently committed to undertake an Industrial Electricity Policy Review during the BCUC Certificate of Public Convenience and Necessity (CPCN) proceeding related to the DCAT Project.

The Review was officially launched in late January 2013 when a three person panel was appointed by Government. The main issue to be reviewed is with regard to changes to transmission voltage rates, or the regulatory framework within which those rates are established, and which could be made to advance the objectives of electricity conservation, economic development and take into account the current environmental policy. On June 19, 2013, the Government extended the deadline for the completion of the review to October 31, 2013. In addition, Government supplemented the Terms of Reference to include a review of Industrial Time-of-Use rates, utility interconnection and retail access policies in other relevant jurisdictions.

NEW POWER PURCHASE AGREEMENT WITH FORTISBC

In May 2013, BC Hydro filed an application with the BCUC for approval of a new 20-year Power Purchase Agreement (PPA) with FortisBC. BC Hydro's current PPA with FortisBC has been in place since 1993 and is expiring on September 30, 2013. BC Hydro and FortisBC have been in negotiations for a new agreement for several years. BC Hydro has requested a written hearing process to review the application. A procedural conference was held on July 29, 2013 and the BCUC is in the process of making its decision on the review process.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for three months ended June 30, 2013 was $46 million, compared with cash flow provided by operating activities of $34 million in the prior fiscal year. The increase was primarily due to an increase in cash flows from net income before regulatory transfers due to higher revenues, partially offset by higher energy costs.

The long-term debt balance net of sinking funds at June 30, 2013 was $14.6 billion, compared with $14.0 billion at March 31, 2013. The increase was mainly as a result of an increase in revolving borrowings of $637 million, an increase of long term debt bond issues totaling $324 million ($350 million par value), and net foreign exchange revaluation losses of $35 million. These increases were partially offset by long-term bond redemptions totaling $356 million par value and net gains on economic hedging activities of $8 million.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

	For the three months ended June 30	
(in millions)	**2013**	2012
Distribution system improvements and expansion	**$ 66**	$ 76
Generation replacements and expansion	**101**	91
Transmission lines and substation replacements & expansion	**176**	145
Smart Metering and Infrastructure program	**24**	97
General, including computers, vehicles and building improvements	**35**	26
Total Property, Plant and Equipment Expenditures	**$ 402**	$ 435

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

Distribution capital expenditures for the first quarter ended June 30, 2013 were $66 million which included expenditures on customer driven work and asset replacements and system expansion and improvements.

Generation capital expenditures for the first quarter ended June 30, 2013 were $101 million which includes expenditures for the Ruskin Dam and Powerhouse Upgrade, Mica Unit 5 & Unit 6 Installation and G.M. Shrum Units 1 to 5 Turbine Replacement major projects.

Transmission capital expenditures for the first quarter ended June 30, 2013 were $176 million which includes expenditures for the Interior to Lower Mainland Transmission, Northwest Transmission Line, Merritt Area Transmission and Vancouver City Central Transmission projects.

SMI capital expenditures for the first quarter ended June 30, 2013 were $24 million which primarily included expenditures for meter installations and network equipment purchases.

General capital expenditures for the first quarter ended June 30, 2013 were $36 million which primarily included expenditures on various technology projects and properties programs.

RISK MANAGEMENT

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

The Company strives to manage all the risks it faces on a cost effective basis, taking into account the potential reward to be gained in return for acceptance of the risk. The Company also strives to manage significant risks in conformity with the provisions of the international standard ISO 31000, "*Risk Management – Principles and Guidelines*", or in conformity with the provisions of other externally recognized standards appropriate to the risk being managed.

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

This section should be read in conjunction with the risks disclosed in the Risk Management section in the Management's Discussion and Analysis presented in the Annual Report for the year ended March 31, 2013.

LOAD/ENERGY RESOURCE BALANCE

Variations in system inflows, market prices, and domestic load can significantly influence cost of energy. The system inflow energy for fiscal 2013 was 9 per cent above average, with unusually high water conditions and some flooding impacts during the spring and summer of 2012. The system inflow energy for fiscal 2014 is 100 per cent of average. Largely due to high inflow conditions, net market sales for fiscal 2013 were approximately 6,500 GWh (equivalent to 12 per cent of our domestic load). For fiscal 2014, the current forecast of net market sales is 1,700 GWh (equivalent to 3 per cent of our domestic load).

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

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

FUTURE OUTLOOK

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

BC Hydro filed a revised Service Plan in June 2013 that was incorporated as part of the Provincial Government Budget Update. The revised Service Plan forecasts net income for fiscal 2014 to remain unchanged at $545 million.

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 forecast for fiscal 2014 assumes average water inflows, domestic load of 56,538 GWh, average market electricity prices of U.S. $29.23/MWh, short-term interest rates of 1.39 per cent, a U.S. dollar exchange rate of U.S. $1.0119, an allowed return on equity of 11.84 per cent, and an approved rate increase of 1.44 per cent for fiscal 2014.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	*For the three months ended June 30* 2013	2012
Revenues		
Domestic	**$ 947**	$ 894
Trade	**307**	164
	1,254	1,058
Expenses		
Operating Expenses (Note 4)	**1,051**	874
Finance Charges (Note 5)	**148**	131
Net Income	**55**	53
OTHER COMPREHENSIVE INCOME		
Items Reclassified Subsequently to Net Income		
Effective portion of changes in fair value of derivatives designated as cash flow hedges	**17**	(5)
Reclassification to income on derivatives designated as cash flow hedges	**(27)**	(15)
Foreign currency translation gains	**5**	2
Other Comprehensive Loss	**(5)**	(8)
Total Comprehensive Income	**$ 50**	$ 45

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(in millions)	As at June 30 2013	As at March 31 2013
ASSETS		
Current Assets		
Cash and cash equivalents	$ 34	$ 60
Accounts receivable and accrued revenue	670	721
Inventories (Note 7)	183	173
Prepaid expenses	206	201
Current portion of derivative financial instrument assets (Note 14)	106	83
	1,199	1,238
Non-Current Assets		
Property, plant and equipment (Note 8)	17,452	17,226
Intangible assets (Note 8)	452	438
Regulatory assets (Note 9)	4,967	4,741
Sinking funds	118	112
Derivative financial instrument assets (Note 14)	28	27
	23,017	22,544
	$ 24,216	$ 23,782
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Notes 11 and 13)	$ 1,452	$ 1,544
Current portion of long-term debt (Note 10)	3,888	3,288
Current portion of derivative financial instrument liabilities (Note 14)	51	172
	5,391	5,004
Non-Current Liabilities		
Long-term debt (Note 10)	10,879	10,846
Regulatory liabilities (Note 9)	294	307
Derivative financial instrument liabilities, long-term (Note 14)	76	94
Contributions in aid of construction	1,248	1,196
Post employment benefits	1,402	1,396
Other long-term liabilities (Note 13)	1,376	1,439
	15,275	15,278
Shareholder's Equity		
Contributed surplus	60	60
Retained earnings	3,424	3,369
Accumulated other comprehensive income	66	71
	3,550	3,500
	$ 24,216	$ 23,782

Commitments and Contingencies (Note 8 and 15)

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

Approved on Behalf of the Board:

Stephen Bellringer
Chairman

Tracey L. McVicar
Chair, Audit & Finance Committee

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve	Unrealized Gains/(Losses) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income	Contributed Surplus	Retained Earnings	Total
Balance, April 1, 2012	$ 21	$ 63	$ 84	$ 60	$ 3,075	$ 3,219
Payment to the Province	-	-	-	-	-	-
Comprehensive Income (Loss)	2	(10)	(8)	-	53	45
Balance, June 30, 2012	$ 23	$ 53	$ 76	$ 60	$ 3,128	$ 3,264
Balance, April 1, 2013	$ 17	$ 54	$ 71	$ 60	$ 3,369	$ 3,500
Payment to the Province	-	-	-	-	-	-
Comprehensive Income (Loss)	5	(10)	(5)	-	55	50
Balance, June 30, 2013	$ 22	$ 44	$ 66	$ 60	$ 3,424	$ 3,550

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(in millions)	*For the three months ended June 30* 2013	2012
Operating Activities		
Net income	**$ 55**	$ 53
Regulatory account transfers	**(310)**	(131)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 9)	**71**	74
Amortization and depreciation expense	**162**	152
Unrealized gains on mark-to-market	**(70)**	(12)
Interest accrual	**159**	150
Other items	**26**	8
	93	294
Changes in:		
Accounts receivable and accrued revenue	**56**	9
Prepaid expenses	**(5)**	(18)
Inventories	**(7)**	(16)
Accounts payable, accrued liabilities and other long-term liabilities	**85**	(83)
Contributions in aid of construction	**61**	64
	190	(44)
Interest paid	**(237)**	(216)
Cash provided by operating activities	**46**	34
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(376)**	(389)
Cash used in investing activities	**(376)**	(389)
Financing Activities		
Long-term debt:		
Issued	**327**	657
Retired	**(356)**	-
Receipt of revolving borrowings	**2,182**	1,532
Repayment of revolving borrowings	**(1,544)**	(1,603)
Settlement of hedging derivatives	**(84)**	-
Payment to the Province (Note 11)	**(215)**	(230)
Other items	**(6)**	(6)
Cash provided by financing activities	**304**	350
Decrease in cash and cash equivalents	**(26)**	(5)
Cash and cash equivalents, beginning of period	**60**	12
Cash and cash equivalents, end of period	**$ 34**	$ 7

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

NOTE 1: REPORTING ENTITY

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, conserve and supply power. BC Hydro owns and operates electric generation, transmission and distribution facilities in the province of British Columbia.

The condensed consolidated interim financial statements of BC Hydro include the accounts of BC Hydro and its principal wholly-owned operating subsidiaries including Powerex, Powertech Labs Inc., and Columbia Hydro Constructors Ltd., (collectively with BC Hydro, "the Company") including BC Hydro's one third interest in the Waneta Dam and Generating Facility (Waneta). All intercompany transactions and balances are eliminated upon consolidation.

The Company accounts for its one third interest in Waneta as a joint operation. The consolidated financial statements include the Company's proportionate share in Waneta, including its share of any liabilities and expenses incurred jointly with Teck Metals Ltd. and its revenue from the sale of the output in relation to Waneta.

NOTE 2: BASIS OF PRESENTATION

BASIS OF ACCOUNTING

These condensed consolidated interim financial statements have been prepared in accordance with significant accounting policies that have been established based on the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). In accordance with the directive issued by the Province's Treasury Board, BC Hydro is to prepare its consolidated financial statements in accordance with the accounting principles of International Financial Reporting Standards (IFRS) except that BC Hydro is to apply regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations* (collectively the "Prescribed Standards"). The application of ASC 980 results in BC Hydro recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the British Columbia Utilities Commission (BCUC) for inclusion in future customer rates. Such regulatory costs and recoveries would otherwise be included either in net income or recovered in rates in the periods the amounts are incurred.

The impact of the application of ASC 980 on these condensed consolidated interim financial statements with respect to BC Hydro's regulatory accounts is described in Note 9.

These condensed consolidated interim statements have been prepared by management in accordance with the principles of IAS 34, *Interim Financial Reporting* and the Prescribed Standards and were prepared using the same accounting policies as described in BC Hydro's 2013 Annual Report except as described in Note 3. These interim consolidated financial statements should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2013 Annual Report.

These condensed consolidated interim financial statements were approved by the Board of Directors on August 15, 2013.

NOTE 3: CHANGE IN ACCOUNTING POLICIES

POST EMPLOYMENT BENEFITS

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

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

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

FAIR VALUE MEASUREMENT

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

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

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

NOTE 4: OPERATING EXPENSES

(in millions)	*For the three months ended June 30* 2013	2012
Electricity and gas purchases	$ **418**	$ 265
Water rentals	**77**	74
Transmission charges	**36**	32
Personnel expenses	**140**	137
Materials and external services	**141**	145
Amortization and depreciation (Note 6)	**244**	230
Grants and taxes	**51**	48
Capitalized costs	**(58)**	(62)
Other costs / (recoveries)	**2**	5
Total	$ **1,051**	$ 874

NOTE 5: FINANCE CHARGES

(in millions)	*For the three months ended June 30* 2013	2012
Interest on long-term debt	$ **181**	$ 157
Interest on finance lease liabilities	**12**	7
Net interest expense on net defined benefit liability	**3**	3
Less: capitalized interest	**(26)**	(18)
Total finance costs	**170**	149
Other costs (recoveries)	**(22)**	(18)
Total	$ **148**	$ 131

NOTE 6: AMORTIZATION AND DEPRECIATION

(in millions)	*For the three months ended June 30* 2013	2012
Depreciation of property, plant and equipment	$ **147**	$ 140
Amortization of intangible assets	**15**	14
Amortization of regulatory accounts	**82**	76
Total	$ **244**	$ 230

NOTE 7: INVENTORIES

During the three month period ended June 30, 2013, an impairment of $3 million (2012 – impairment recovery of $8 million) was charged to cost of energy to adjust the recorded value of natural gas inventories as a result of a decrease in market prices. As at June 30, 2013, $39 million (June 30, 2012 - $53 million) of the value of natural gas inventories was valued at net realizable value.

NOTE 8: PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Property, plant and equipment and intangible asset expenditures for the three months ended June 30, 2013 were $402 million (2012 - $435 million).

As of June 30, 2013, the Company has contractual commitments to spend $1,010 million on major property, plant and equipment projects (for individual projects greater than $50 million).

NOTE 9: RATE REGULATION

REGULATORY ACCOUNTS

The following regulatory assets and liabilities have been established through rate regulation. In the absence of rate regulation, these amounts would be reflected in operating results in the year which they are incurred. For the period ended June 30, 2013, the impact of regulatory accounting has resulted in an increase of $239 million to comprehensive income (2012 - $57 million increase). For each regulatory account, the amount reflected in the Net Change column in the following regulatory tables represents the impact on comprehensive income for the applicable year. Under rate regulated accounting, a net decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to comprehensive income.

(in millions)	*April 1 2013*	*Addition (Reduction)*	*Amortization*	*Net Change*	*June 30 2013*
Regulatory Assets					
Heritage Deferral Account	$ 70	$ 9	$ (4)	$ 5	$ 75
Non-Heritage Deferral Account	467	33	(27)	6	473
Trade Income Deferral Account	190	169	(11)	158	348
Demand-Side Management Programs	733	21	(16)	5	738
First Nation Negotiations, Litigation & Settlement Costs	553	10	(1)	9	562
Non-Current Pension Cost	544	(4)	(4)	(8)	536
Site C	258	14	–	14	272
CIA Amortization Variance	75	1	–	1	76
Environmental Provisions	367	(12)	(1)	(13)	354
Smart Metering and Infrastructure	192	22	–	22	214
Finance Charges	1	(1)	–	(1)	–
IFRS Pension & Other Post-Employment Benefits	723	–	(9)	(9)	714
IFRS Property, Plant and Equipment	447	45	(2)	43	490
Other Regulatory Accounts	121	1	(7)	(6)	115
Total Regulatory Assets	4,741	308	(82)	226	4,967
Regulatory Liabilities					
Future Removal and Site Restoration Costs	88	–	(11)	(11)	77
Rate Smoothing	111	(25)	–	(25)	86
Foreign Exchange Gains and Losses	100	(4)	–	(4)	96
Finance Charges	–	22	–	22	22
Other Regulatory Accounts	8	5	–	5	13
Total Regulatory Liabilities	307	(2)	(11)	(13)	294
Net Regulatory Asset	$ 4,434	$ 310	$ (71)	$ 239	$ 4,673

During April 2013, the British Columbia Utilities Commission (BCUC) issued the Generic Cost of Capital (GCOC) decision which resulted in a reduction in the Benchmark Utility Return on Equity from 9.5 per cent to 8.75 per cent which would result in a decrease to the BC Hydro allowed rate of return (ROE) for fiscal 2014 from 11.84 per cent to 10.61 per cent. However, the Province has advised BC Hydro that it intends to issue a direction or regulation in the fall of 2013 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget. Had the impact of the GCOC decision been reflected in the quarter ended June 30, 2013, the Non-Heritage Deferral Account, and consequently net income, would have been approximately $12.5 million lower than recorded.

During August 2013, the Company's subsidiary Powerex reached a settlement agreement subject to the Federal Energy Regulatory Commission (FERC) approval with parties involved in the various ongoing legal claims in California to resolve all outstanding claims and litigation filed against it arising from events and transactions in the California power market during the 2000 and 2001 period (see Note 15). This was accounted for as an adjusting subsequent event which resulted in an expense of $214 million which was recorded as of June 30, 2013. The Province has advised BC Hydro that it intends to issue a direction or regulation in the fall of 2013 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget and as a result, the loss was fully deferred to the Trade Income Deferral Account (TIDA).

OTHER REGULATORY ACCOUNTS

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

NOTE 10: LONG-TERM DEBT AND DEBT MANAGEMENT

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

In the three month period ended June 30, 2013, the Company issued bonds with net proceeds of $327 million and par value of $350 million (2012- net proceeds of $657 million and par value of $578 million), a weighted average effective interest rate of 3.6 per cent (2012- 3.4 per cent) and a weighted average term to maturity of 33.6 years (2012 - 26.1 years).

NOTE 11: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining the Company's equity for regulatory purposes, as well as the annual Payment to the Province. Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province and a limit on the Payment to the Province if it would cause the debt to equity ratio to exceed 80:20.

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

During the three months ended June 30, 2013, there were no changes in the approach to capital management.

The debt to equity ratio at June 30, 2013 and March 31, 2013 was as follows:

(in millions)	**As at June 30 2013**	As at March 31 2013
Total debt, net of sinking funds	**$ 14,649**	$ 14,022
Less: Cash and cash equivalents	**(34)**	(60)
Net Debt	**$ 14,615**	$ 13,962
Retained earnings	**$ 3,424**	$ 3,369
Contributed surplus	**60**	60
Accumulated other comprehensive income	**66**	71
Total Equity	**$ 3,550**	$ 3,500
Net Debt to Equity Ratio	**80 : 20**	80 : 20

PAYMENT TO THE PROVINCE

The Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Province, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. No Payment has been accrued as at June 30, 2013 (March 31, 2013 - $215 million, included in accounts payable and accrued liabilities) as the Company's debt to equity ratio is at the 80:20 cap prior to the calculation of the Payment.

NOTE 12: POST EMPLOYMENT BENEFITS

TThe expense recognized in the statement of comprehensive income for the Company's defined benefit plans prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions and prior to the application of regulatory accounting for the three months ended June 30, 2013 was $39 million (2012 - $23 million).

Contributions to the registered defined benefit pension plans for the three months ended June 30, 2013 were $12 million (2012 - $12 million).

NOTE 13: OTHER LONG-TERM LIABILITIES

(in millions)	**June 30 2013**	March 31 2013
Provisions		
Environmental liabilities	**$ 322**	$ 340
Decommissioning obligations	**51**	52
Other	**47**	43
Total Provisions	**420**	435
First Nations liabilities	**387**	387
Finance lease obligations	**288**	292
Deferred revenue - Skagit River Agreement	**419**	423
	1,514	1,537
Less: Current portion, included in accounts payable and accrued liabilities	**(138)**	(98)
Total	**$ 1,376**	$ 1,439

NOTE 14: FINANCIAL INSTRUMENTS

CATEGORIES OF FINANCIAL INSTRUMENTS

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at June 30, 2013:

	2013		Interest Income (Expense) recognized in Finance Charges
(in millions)	Carrying Value	Fair Value	2013
Financial Assets and Liabilities at Fair Value Through Profit or Loss:			
Short-term investments	$ 9	$ 9	$ –
Designated long-term debt	(354)	(354)	(7)
Loans and Receivables:			
Accounts receivable and accrued revenue	670	670	–
Cash	25	25	–
Held to Maturity:			
Sinking funds – US	118	131	1
Other Financial Liabilities:			
Revolving borrowings - CAD	(1,602)	(1,602)	(12)
Revolving borrowings - US	(1,608)	(1,608)	–
Accounts payable and accrued liabilities	(1,452)	(1,452)	–
Long-term debt (including current portion due in one year)	(11,203)	(12,613)	(162)
First Nations liability (long-term portion only)	(373)	(473)	–
Finance Lease Obligation (long-term portion only)	(272)	(272)	(12)

For non-derivative financial assets and liabilities classified as financial assets and liabilities at fair value through profit or loss, a $8 million gain has been recognized in net income for the three months ended June 30, 2013 relating to changes in fair value. For short-term investments, loans and receivables, and accounts payable and accrued liabilities, the carrying value approximates fair value due to the short duration of these financial instruments.

The fair value of derivative instruments designated and not designated as hedges, was as follows:

	2013	
(in millions)	Carrying Value	Fair Value
Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	$ (56)	$ (56)
Interest rate swaps (fair value hedges for debt)	1	1
	(55)	(55)
Non-Designated Derivative Instruments:		
Foreign currency contracts	39	39
Commodity derivatives	23	23
	62	62
Total	$ 7	$ 7

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

	June 30, 2013
Current portion of derivative financial instrument assets	$ 106
Current portion of derivative financial instrument liabilities	(51)
Derivative financial instrument assets, long-term	28
Derivative financial instrument liabilities, long-term	(76)
Total	$ 7

For the three months ended June 30, 2013, an immaterial amount was recognized in finance charges related to the ineffective portion of designated cash flow hedges. For designated cash flow hedges for the three months ended June 30, 2013, a gain of $17 million was recognized in other comprehensive income. For the three months ended June 30, 2013, $27 million was removed from other comprehensive income and reported in net income, offsetting foreign exchange losses recorded in the period.

For derivative instruments not designated as hedges, a gain of $2 million was recognized in finance charges for the months ended June 30, 2013 with respect to foreign currency contracts for cash management purposes. For the three months ended June 30, 2013, a gain of $41 million was recognized in finance charges with respect to foreign currency contracts for U.S. short-term borrowings. These economic hedges offset $43 million of foreign exchange revaluation losses recorded with respect to U.S. short-term borrowings. A net gain of $10 million was recorded in trade revenue for the three months ended June 30, 2013 with respect to commodity derivatives.

FAIR VALUE HIERARCHY

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

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

Level 1 values are quoted prices (unadjusted) in active markets for identical assets and liabilities.

Level 2 inputs are those other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, as of the reporting date.

Level 3 inputs are those that are not based on observable market data.

The following table presents the financial assets and financial liabilities measured at fair value for each hierarchy level as at June 30, 2013:

As at June 30, 2013	Level 1	Level 2	Level 3	Total
Short-term investments	$ 9	$ –	$ –	$ 9
Derivatives designated as hedges	–	12	–	12
Derivatives not designated as hedges	15	72	34	121
Total financial assets carried at fair value	$ 24	$ 84	$ 34	$ 142
Designated long-term debt	$ –	$ (354)	$ –	$ (354)
Derivatives designated as hedges	–	(67)	–	(67)
Derivatives not designated as hedges	(18)	(39)	(2)	(59)
Total financial liabilities carried at fair value	$ (18)	$ (460)	$ (2)	$ (480)

The Company determines Level 2 fair values for debt securities and derivatives using discounted cash flow techniques, which uses contractual cash flows and market-related discount rates.

Level 2 fair values for energy derivatives are determined using inputs other than unadjusted quoted prices that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices). Level 2 includes bilateral and over-the-counter contracts valued using interpolation from observable forward curves or broker quotes from active markets for similar instruments and other publicly available data, and options valued using industry-standard and accepted models incorporating only observable data inputs.

There were no transfers between Levels 1 and 2 during the period.

The following table reconciles the changes in the balance of financial instruments carried at fair value on the statement of financial position, classified as Level 3, for the three months ended June 30, 2013:

(in millions)	
Balance at April 1, 2013	**$ 34**
Cumulative impact of net gain recognized	8
New transactions	(3)
Existing transactions settled	(7)
Balance at June 30, 2013	**$ 32**

Level 3 fair values for energy derivatives are determined using inputs that are not observable. Level 3 includes instruments valued using observable prices adjusted for unobservable basis differentials such as delivery location and product quality, instruments which are valued by extrapolation of observable market information into periods for which observable market information is not yet available, and instruments valued using internally developed or non-standard valuation models.

A net gain of $9 million recognized in net income during the three months ended June 30, 2013 relates to Level 3 financial instruments held at June 30, 2013. The net loss is recognized in trade revenue.

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

NOTE 15: COMMITMENTS AND CONTINGENCIES

CALIFORNIA LITIGATION

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. FERC has concluded that because of a dysfunctional energy market in California between October 2000 and June 2001, certain market-wide refunds will have to be paid by energy providers, including Powerex, to various California parties.

On August 15, 2013, Powerex entered into a settlement agreement subject to FERC approval with Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, the California Attorney General, and the California Public Utilities Commission to resolve all outstanding litigation and claims filed against it arising from events and transactions in the California power market during the 2000 and 2001 period. As part of the settlement, Powerex made a net cash payment into escrow of US$273 million. The net cash payment was calculated as the difference between the agreed upon settlement amount of US$750 million and the receivables and interest owing from the California parties to Powerex of US$477 million. This was accounted for as an adjusting subsequent event and an expense of CDN$214 million was recorded as of June 30, 2013. The expense recorded was calculated as the net cash settlement amount of CDN$287 million (US$273 million) less amounts previously accrued related to these legal claims of CDN$73 million. The Province has advised BC Hydro that it intends to issue a direction or regulation in the fall of 2013 directing BC Hydro to maintain its net income forecast for fiscal 2014 through fiscal 2016 from the February 2013 Budget. As a result, the loss was deferred to the TIDA.

NOTE 16: SEASONALITY OF OPERATING RESULTS

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