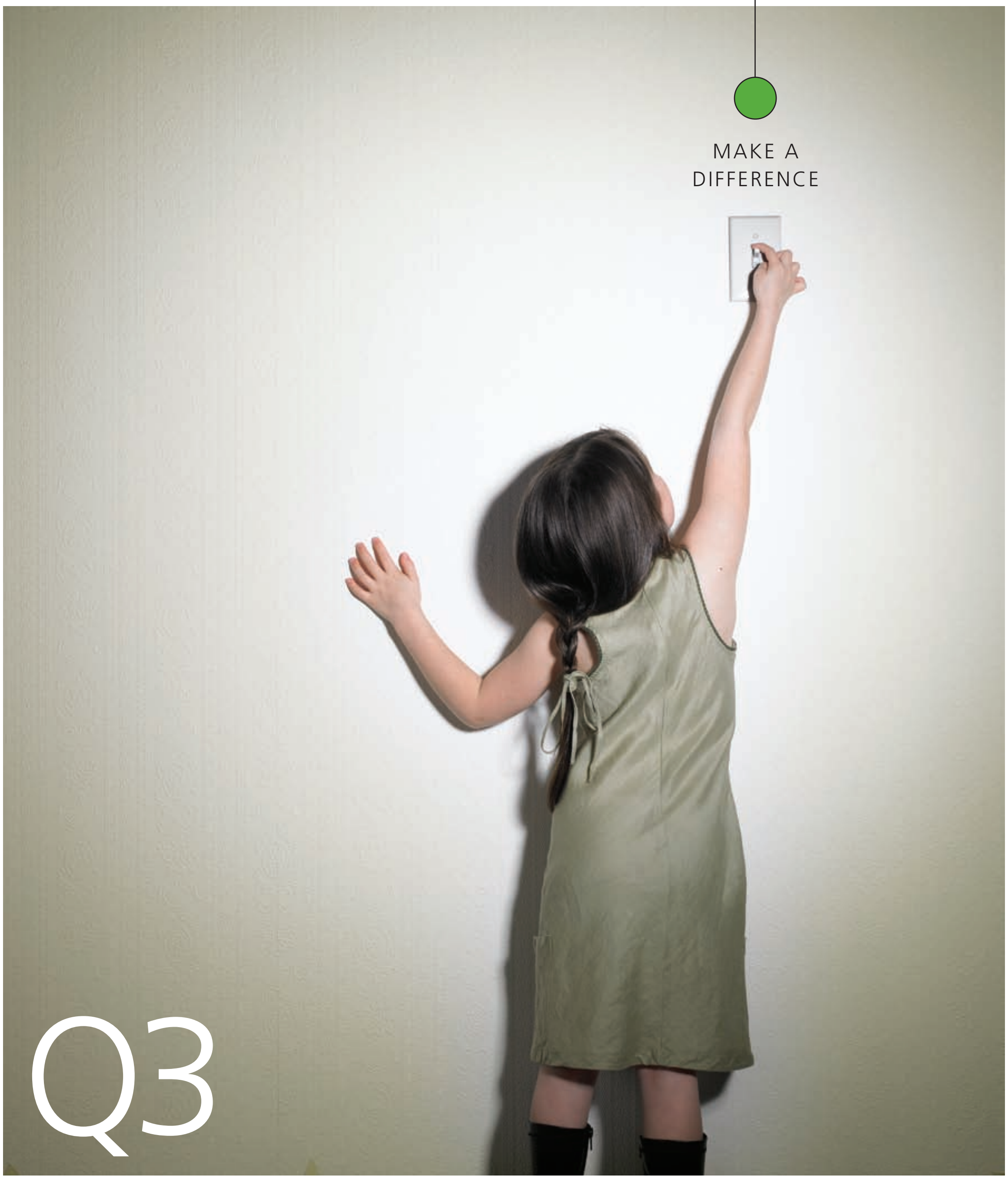
BC HYDRO'S THIRD QUARTER REPORT FISCAL 2008



BRITISH COLUMBIA
The Best Place on Earth

BC hydro
FOR GENERATIONS

Financial

MANAGEMENT DISCUSSION AND ANALYSIS

The Management Discussion and Analysis reports on BC Hydro's consolidated results and financial position for the three and nine months ended December 31, 2007 (fiscal 2008). This section should be read in conjunction with the Management Discussion and Analysis presented in the 2007 Annual Report, 2007 Annual Consolidated Financial Statements of BC Hydro, and the interim consolidated financial statements of BC Hydro for the three and nine months ended December 31, 2007 and 2006. This report contains forward–looking statements, including statements regarding the business and anticipated financial performance of BC Hydro. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward–looking statements.

BC Hydro's results for the third quarter of fiscal 2008 benefited from water inflows being 114 per cent of average and reservoir levels at 112 per cent of average for the period resulting in higher hydro generation, reducing energy purchases resulting in a reduction in the total cost of energy compared to the prior year. Differences to planned amounts are deferred for the benefit of customers.

Highlights

- Net income for the three and nine months ended December 31, 2007 was $188 million and $350 million respectively, compared to $176 million and $380 million for the same periods in fiscal 2007.

- For the nine months ended December 31, 2007 BC Hydro experienced higher than average system inflows (114 per cent of average), resulting in a 25 per cent increase in hydro generation over the prior year. BC Hydro and its customers benefited from this increase by reducing the volume of energy purchased to meet domestic requirements, lowering the overall cost of energy.

- Property, plant and equipment expenditures of $766 million are 42 per cent higher than the prior year ($540 million) primarily due to system resiliency work to enhance its capacity to withstand storms and system capacity additions, ongoing work for the installation of a fifth turbine unit in the Revelstoke dam, stator and rotor pole replacements, and reinforcement work underway on the Vancouver Island transmission connection.

	For the three months ended December 31			**For the nine months ended December 31**		
(in millions)	2007	2006	Change	2007	2006	Change
Income Before Regulatory Accounts	$ 159	$ 143	$ 16	$ 456	$ 305	$ 151
Net Income	$ 188	$ 176	$ 12	$ 350	$ 380	$ (30)
Accrued Payment to the Province	$ 128	$ 113	$ 15	$ 282	$ 312	$ (30)
Number of Domestic Customers	–	–	–	1,758,958	1,727,665	31,293
GWh Sold (Domestic)	14,182	14,134	48	39,355	38,358	997
Total Reservoir Storage (GWh)	–	–	–	23,706	22,532	1,174

(in millions)	**December 31 2007**	**March 31 2007**	**Change**
Total Assets	$ 13,132	$ 12,861	$ 271
Retained Earnings	$ 1,913	$ 1,783	$ 130
Debt to Equity[1]	70:30	70:30	–

[1] *Based on equity as defined for regulatory purposes*

Consolidated Results of Operations

For the quarter ended December 31, 2007, income before regulatory account transfers was $159 million compared to $143 million for the same period in fiscal 2007. The increase was a result of higher domestic gross margins arising primarily from lower energy costs and lower finance charges, offset by higher operating costs, lower trade gross margin and higher amortization expense.

For the nine months ended December 31, 2007, income before regulatory account transfers was $456 million compared to $305 million for the same period in fiscal 2007. The increase was a result of higher domestic gross margin primarily from lower energy costs and lower amortization expense as the prior year included a one time $24 million charge to depreciation to revise certain asset service lives. This is partially offset by lower trade gross margin, higher operating costs, and higher finance charges.

Net income for the quarter ended December 31, 2007 was $188 million compared with $176 million in fiscal 2007. Net income is higher than income before regulatory accounts mainly due to reduced market energy purchases and the deferral of operating costs related to major projects that will be recovered through customer rates in future years. The increase in net income from the prior year is mainly due to higher domestic margin offset by lower trade margin and higher finance charges.

Net income for the nine months ended December 31, 2007 was $350 million, compared with $380 million for the same period in fiscal 2007. Net income is lower than before regulatory accounts mainly due to the benefit of reduced market energy purchases being deferred and offset against high energy costs in the prior years. The decrease in net income from the prior year is mainly due to lower trade gross margins and higher finance charges offset by lower amortization expense.

Revenues

For the three months ended December 31	*(in millions)*		*(gigawatt hours)*	
	2007	2006	2007	2006
Domestic				
Residential	$ 335	$ 291	5,059	4,834
Light industrial and commercial	265	251	4,610	4,603
Large industrial	132	132	3,873	4,059
Other energy sales	42	50	640	638
Total Domestic	$ 774	$ 724	14,182	14,134
Trade				
Electricity	$ 234	$ 265	8,026	6,222
Gas	230	123	4,071	1,425
Total Trade	464	388	12,097	7,647
Total	$ 1,238	$ 1,112	26,279	21,781

For the nine months ended December 31	*(in millions)*		*(gigawatt hours)*	
	2007	2006	2007	2006
Domestic				
Residential	$ 813	$ 740	12,131	11,577
Light industrial and commercial	776	749	13,546	13,431
Large industrial	392	400	11,560	12,038
Other energy sales	125	76	2,118	1,312
Total Domestic	$ 2,106	$ 1,965	39,355	38,358
Trade				
Electricity	$ 850	$ 741	31,352	26,052
Gas	551	356	10,097	5,471
Total Trade	1,401	1,097	41,449	31,523
Total	$ 3,507	$ 3,062	80,804	69,881

Financial

Total revenue for the three and nine months ended December 31, 2007 was $1,238 million and $3,507 million, an increase of $126 million and $445 million, respectively, over the same period last year. Domestic revenues increased overall due to higher average customer rates and increased consumption driven primarily by customer growth and colder temperatures for the residential and light industrial and commercial sectors. These increases were offset by lower revenues from large industrial customers due to the coastal forestry strike and reduced demand for lumber. Trade revenues were higher as a result of higher trade volumes, partially offset by lower average commodity prices.

Domestic Revenues

Total domestic revenues of $774 million for the third quarter were $50 million or seven per cent higher than for the same period in the previous year. Total sales volumes increased slightly over last year as a result of higher average customer rates, an additional 31,293 new customers (including 10 large industrial) added to the system, and an increase in average consumption in the residential and light industrial and commercial sectors due to colder weather. This was partially offset by lower consumption in the pulp and paper industry due to the coastal forestry strike and reduced demand for lumber in the U.S. housing market.

Total domestic revenues of $2,106 million for the nine months ended December 31, 2007 were $141 million or seven per cent higher than for the same period in the previous year. Total domestic sales volumes increased by three per cent as a result of increased average consumption in the residential and light industrial and commercial sectors due to customer growth and colder weather as well as higher average customer rates. This was offset by a decline in large industrial revenue resulting from lower consumption in the pulp and paper industry primarily due to the coastal forestry strike.

Trade Revenues

BC Hydro's electricity system is interconnected with systems in Alberta and the western United States. Interconnection facilitates sales and purchases of electricity outside of British Columbia. Energy trade activities are carried out by Powerex, a wholly owned subsidiary of BC Hydro. 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.

Trade revenue for the third quarter was $464 million, an increase of 20 per cent compared to $388 million in the third quarter of the prior year. The increase was due to a $107 million increase in gas revenue which was driven by a 186 per cent increase in gas sales volumes, partially offset by a decrease of 28 per cent in the average gas sales price. Gas sales volumes rose to 4,071 GWh for the third quarter from 1,425 GWh in the same quarter of the prior year as a result of increased gas trading activity. The average gas sales price fell as the prior year had more volatility in prices which provided increased opportunity to sell during periods of higher prices. The increase in gas revenue was partially offset by a decrease in electricity revenue of $31 million as a result of a 15 per cent decrease in the average electricity sales price to a gross price of $61/MWh from $72/MWh in the same quarter of the prior year.

Trade revenues for the nine months ended December 31, 2007 are $1,401 million, an increase of 28 per cent compared to $1,097 million in the same period last year. The increase is primarily due to a $195 million increase in gas revenue as a result of an 85 per cent increase in gas sales volumes to 10,097 GWh in the current year compared to 5,471 GWh for the same period last year. In addition, electricity revenue increased by $109 million primarily as a result of a 20 per cent increase in sales volumes to 31,352 GWh compared to 26,052 GWh in the prior year.

Energy Costs

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 made up of the following sources of supply:

For the three months ended December 31	*(in millions)*		*(gigawatt hours)*		*($ per MWh)*[2]	
	2007	2006	2007	2006	2007	2006
Hydro generation	$ 84	$ 71	14,337	12,453	$ 5.75	$ 5.75
Purchases from Independent Power Producers and other long-term contracts	130	68	2,200	1,294	59.22	52.48
Domestic electricity purchases	12	61	217	1,114	55.05	54.72
Gas for thermal generation	12	29	97	384	123.05	74.87
Transmission charges and other expenses	13	3	30	32	–	–
Allocation to trade energy	(41)	41	(807)	543	54.43	67.71
Total Domestic	$ 210	$ 273	16,074	15,820	$ 13.05	$ 17.27
Other electricity purchases – trade[1]	$ 126	$ 153	7,177	6,722	$ 52.56	$ 56.05
Remarketed gas	218	105	4,177	1,496	52.30	70.05
Transmission charges and other	54	47	–	–	–	–
Allocation from domestic energy	41	(41)	807	(543)	54.43	67.71
Total Trade	$ 439	$ 264	12,161	7,675	$ 56.77	$ 63.53
Total Energy Costs	$ 649	$ 537	28,235	23,495	$ 31.88	$ 32.38

For the nine months ended December 31	*(in millions)*		*(gigawatt hours)*		*($ per MWh)*[2]	
	2007	2006	2007	2006	2007	2006
Hydro	$ 228	$ 181	38,573	31,251	$ 5.89	$ 5.87
Purchases from Independent Power Producers and other long-term contracts	357	266	5,965	4,582	59.80	58.02
Domestic electricity purchases	40	198	776	4,706	51.47	42.17
Thermal	34	63	322	919	105.28	69.00
Transmission charges and other expenses	46	33	79	79	–	–
Allocation to trade energy	(123)	55	(2,331)	506	55.45	63.93
Total Domestic	$ 582	$ 796	43,384	42,043	$ 13.42	$ 18.92
Other electricity purchases - trade[1]	$ 400	$ 299	28,040	26,385	$ 55.22	$ 49.64
Remarketed Gas	533	319	10,403	5,758	51.24	55.37
Transmission charges and other expenses	184	176	–	–	–	–
Allocation from domestic energy	123	(55)	2,331	(506)	55.45	63.93
Total Trade	$1,240	$ 739	40,774	31,637	$ 58.59	$ 55.32
Total Energy Costs	$1,822	$1,535	84,158	73,680	$ 35.31	$ 34.55

[1]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.

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

Total energy costs for the third quarter of fiscal 2008 were $649 million, $112 million (21 per cent) higher than the third quarter last year, primarily as a result of increased gas trade volumes, offset by lower domestic energy purchases.

For the nine months ended December 31, 2007, total energy costs of $1,822 million were $287 million higher than the same period last year primarily due to higher trade energy volumes at higher average unit prices, offset by lower domestic energy purchases due to increased hydro generation.

Domestic Energy Costs

Domestic energy costs of $210 million were $63 million or 24 per cent lower than the third quarter of fiscal 2007. The primary reason for the decrease was the reduction of market energy purchases as BC Hydro increased hydro generation to mitigate the impact of higher water inflows and rising storage levels. This was partially offset by increased transmission costs, purchases from Alcan under the new long term energy purchase agreement and increased purchases from Island Cogeneration Generating Station.

Domestic energy costs of $582 million were $214 million or 27 per cent lower than the nine months ended December 31, 2007. The change is primarily a result of the increased use of hydro generation and lower domestic purchases from the market compared to fiscal 2007.

Trade Energy Costs

Trade cost of energy for the third quarter was $439 million, an increase of 66 per cent compared to $264 million for the third quarter of last year. The increase was due to a $113 million increase in the cost of gas purchases due to a 179 per cent increase in gas purchase volumes, partially offset by a decrease of 25 per cent in the average gas purchase price. Gas purchase volumes rose to 4,177 GWh for the third quarter from 1,496 GWh in the same quarter of the prior year as a result of increased gas trading activity. The average gas purchase price decreased as the prior year had more volatility in prices which resulted in more purchases during periods of higher prices. The increase in the cost of gas purchases was partially offset by a decrease in the cost of electricity purchases of $27 million in the quarter as a result of a five per cent decrease in the average electricity purchase price to a gross price of $53/MWh from $56/MWh in the same quarter of the prior year.

Trade cost of energy for the nine months ended December 31, 2007 is $1,240 million, an increase of 68 per cent compared to $739 million for the same period last year. The increase is due to a $214 million increase in the cost of gas purchases as a result of an 81 per cent increase in gas purchase volumes to 10,403 GWh in the current year compared to 5,758 GWh for the same period last year. In addition, cost of electricity purchases increased by $101 million primarily as a result of a six per cent increase in purchase volumes to 28,040 GWh compared to 26,385 GWh in the prior year.

Water Inflows

Water inflows into BC Hydro's reservoirs were 114 per cent higher than average during the third quarter in fiscal 2008. As a result of these increased water inflows, BC Hydro increased hydro generation 25 per cent over the prior year, with a resulting decrease in domestic energy purchases. The decision to utilize hydro generation instead of import energy is based on many factors, such as the forecast water inflows, current reservoir levels, forecast market price of energy in future periods relative to the current period, and future demand requirements. Operating constraints related to legal and regulatory obligations such as minimum reservoir levels and stream flow requirements also affect the decision to import energy.

To manage the higher inflows, BC Hydro reservoirs have been managed such that the combined storage in BC Hydro reservoirs at December 31, 2007 were 112 per cent of average compared with 106 per cent of average at December 31, 2006 (average storage levels relate to the average from 1986 to 2007), with the Williston Reservoir on the Peace River system at 117 per cent of average (fiscal 2007 – 101 per cent) and the Kinbasket Reservoir on the Columbia River system at 100 per cent of average (fiscal 2007 – 115 per cent).

Operating Costs

Operations costs for the three and nine months ended December 31, 2007 of $75 million and $200 million were $8 million and $19 million higher than in the same period last year. These increases arose from increased demand side management costs and expenditures to investigate the use of smart meters due to increased focus on energy conservation.

Maintenance costs for the three and nine months ended December 31, 2007 of $84 million and $222 million were $2 million lower and $14 million higher than in the same period in the prior year. The decrease for the third quarter was primarily the result of decreased system restoration costs as BC Hydro experienced severe storms during the third quarter of the previous year. This was offset for the year by increased vegetation work to improve system resiliency for the storm season.

Administration costs for the three and nine months ended December 31, 2007 of $31 million and $76 million were unchanged and $22 million lower than the prior year. The decrease for the year was due to lower non-current service pension costs resulting from improved returns on the pension plan assets.

Amortization Expense

Amortization expense of $86 million for the third quarter was $3 million higher than for the same period in the previous year due to increased assets in service and the write off of assets related to the Northern Transmission Line project, partially offset by gains realized on the disposal of a compressor asset. Amortization expense of $267 million for the nine months ended December 31, 2007 was $13 million lower than for the same period in the previous year. This was due to the disposal of the compressor asset as well as a one-time charge recorded in fiscal 2007 to reduce net book values by $24 million as a result of the implementation of the recommendations in a depreciation study undertaken by BC Hydro and gains realized on the disposal of assets. This impact is partially offset by an increase in assets in service compared to the prior year and the asset write offs referred to above.

Finance Charges

Finance charges of $116 million for the third quarter were $13 million lower than for the same period in the previous year. The decrease is mainly due to foreign currency translation as a result of gains on U.S. dollar denominated debt due to the strengthening Canadian dollar and higher interest during construction capitalized. These favourable variances were partially offset by a higher average volume of debt.

Finance charges of $348 million for the nine months ended December 31, 2007, were $4 million higher than for the same period in the previous year The increase is due to a higher average volume of debt, lower sinking fund income as a result of realized capital losses in the current year compared to the prior year, losses from mark-to-market adjustments on certain risk management activities, and foreign exchange translation losses on the revaluation of U.S. sinking funds and net working capital balance. This was partially offset by translation gains on unhedged U.S. dollar denominated debt due to the strengthening Canadian dollar and higher interest during construction capitalized.

Accounting Policies

On April 1, 2007, BC Hydro adopted four new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Handbook Section 1530, Comprehensive Income, Handbook Section 3855, Financial Instruments – Recognition and Measurement, Handbook Section 3861, Financial Instruments – Disclosure and Presentation, and Handbook Section 3865, Hedges. The Company adopted these standards retroactively with an adjustment of opening accumulated other comprehensive income and retained earnings; accordingly, comparative amounts for prior periods have not been restated.

Upon adoption of Section 1530 a new category, accumulated other comprehensive income (AOCI), was added to shareholder's equity. Comprehensive income consists of net income and other comprehensive income (OCI). OCI represents changes in shareholder's equity during a period arising from transactions and changes in the fair value of the effective portion of cash flow hedging instruments. Amounts are recorded in OCI until the criteria for recognition in the consolidated statement of income are met.

Section 3855 establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the standard.

Section 3865 expands the guidelines provided in Accounting Guideline 13, Hedging Relationships, by specifying the criteria that must be satisfied in order for hedge accounting to be applied and the accounting for fair value hedges and cash flow hedges. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

Refer to note 2 in the interim consolidated financial statements for more detailed discussion and analysis regarding the adoption of these new standards.

Powerex Legal Proceedings

Since 2000, Powerex has been named, along with other energy providers, in a number of 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. These proceedings are at various stages.

The U.S. Court of Appeals for the Ninth Circuit has remanded back to the U.S. Federal Energy Regulatory Commission (FERC) the Lockyer case with instructions that FERC should reconsider its remedial powers thereby opening up the possibility that refunds will have to be paid for energy sales during the period May to October 2000. In other cases, the Ninth Circuit has issued conflicting decisions on whether refunds should be paid relating to bilateral sales. It rejected FERC's categorical exclusion of bilateral purchases and remanded one case back to FERC opening up the possibility that Powerex would have to pay refunds for energy sales during the period January to June 2001. Powerex is seeking rehearing of that decision. As it relates to the period from October to December 2000, FERC has already decided that refunds will have to be paid but the precise amount has not been determined.

At December 31, 2007, Powerex was owed US $268 million (CDN $265 million) by the markets operated by the California Power Exchange (Cal Px) and the California Independent System Operator (CISO) related to Powerex' electricity trade activities in California during the period covered by the lawsuits. As a result of defaults by a number of California utilities, the Cal Px and CISO were unable to pay these amounts to Powerex. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

FERC has approved a settlement agreement between FERC staff and Powerex that acknowledged that there was no evidence that Powerex engaged in any gaming practices or concerted partnership practices with any other market participants, and further noted that Powerex was a valuable and reliable supplier to the California market throughout the energy crisis. FERC has not issued a final order in that settlement.

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

Regulatory Accounts

BC Hydro has established various regulatory accounts with approval of the British Columbia Utilities Commission (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 deferral amounts are then included in customer rates in future periods, subject to approval by the BCUC.

For the three and nine months ended December 31, 2007, BC Hydro transferred, on a net basis, $29 million to regulatory accounts and $106 million from regulatory accounts, compared with $33 million and $75 million transferred to regulatory accounts during the same periods last year. The net balance in the regulatory asset and liability accounts as at December 31, 2007, was $322 million compared to $149 million at December 31, 2006.

The net balance related to the regulatory energy accounts of $68 million is $129 million lower than the prior year due to the lower cost of energy supplied during the year. The Heritage Deferral Account and Non-Heritage Deferral Account regulatory accounts are designed to defer the variance between the actual cost incurred by BC Hydro for energy supplied and the forecast energy cost in the most recent revenue requirements application. As a result of the significantly higher inflows experienced in the current year (114 per cent of average), hydro generation was higher than forecast by 2,176 GWh resulting in lower market purchases required for domestic consumption. The average cost of hydro generation is $5.89 MWh compared to the average cost of $51.47 per MWh for market purchases for the nine month period ended December 31, 2007. These factors resulted in the actual domestic energy cost being significantly lower than the forecast cost by $119 million, resulting in a reduction in the regulatory energy asset accounts.

Rate Design

BC Hydro's Rate Design Application was filed in March 2007 and reviewed at an oral public hearing over the summer. A final decision was issued by the British Columbia Utilities Commission (BCUC) on October 26, 2007.

In that decision, the BCUC directed BC Hydro to rebalance its rates between customer classes so that the revenue earned would be equivalent to the cost incurred to supply electricity for each customer class after three years of equal annual adjustments. Since the total BC Hydro revenue requirement is redistributed between customer classes, the effect of this ruling has no impact on overall BC Hydro revenue.

The BCUC also directed BC Hydro to introduce a residential inclining block rate in the immediate future, with an application for that rate to be filed by March 31, 2007.

The BCUC rejected BC Hydro's proposal to restructure the declining block rate for large commercial customers as well as the proposal to phase out the E-plus discounted rate for interruptible heating load. BC Hydro was directed to file a new rate restructuring proposal for large commercial customers. The majority of BC Hydro's other proposals for amended tariff terms and conditions and simplified distribution extension policy were accepted by the BCUC.

Standing Offer Program

BC Hydro submitted its Standing Offer Program (SOP) application on December 14, 2007, consistent with the policy action in the Provincial Government's 2007 Energy Plan for BC Hydro to establish a standing offer to acquire power from clean electricity projects up to 10 megawatts. This program will substantially simplify the tendering process for small independent power producers, reducing the barriers to the development of their projects.

Over the next two years BC Hydro estimates the SOP will provide an estimated 90 to 900 GWh per year of clean, renewable electricity in addition to the "Environmental Attributes" associated with successful SOP projects. BC Hydro has proposed a base price for electricity for eight regions ranging from $65/MWh in the Peace Region to $79/MWh in the Vancouver Island region.

The BCUC has established a negotiated settlement process for reviewing this application in February 2008.

BC Hydro – Alcan Electricity Purchase Agreement

This contract, filed with the BCUC on September 5, 2007 and approved in a decision on January 29, 2008, replaces last year's agreement with Alcan which was not accepted by the BCUC. The 2007 Electricity Purchase Agreement (2007 EPA) meets all of the concerns previously expressed by the BCUC by providing lower prices, extended terms and an increase in capacity and scheduling services.

Regulatory Account Applications

BC Hydro filed applications with the BCUC in relation to two regulatory accounts which allow for rate recovery deferral to future years for certain cost items. One of the applications requests deferral treatment for approximately $8 million of costs incurred in F2008 in relation to BC Hydro's procurement enhancement initiative. The other application is requesting an amendment to an existing regulatory account regarding First Nations claims provisions.

Liquidity and Capital Resources

Cash flow provided by operating activities for the third quarter was $296 million, compared with $122 million for the same period last year. The increase was primarily due to an increase in net income, a decrease in unrealized gains on mark-to-market, and changes in working capital.

The net long-term debt balance at December 31, 2007, was $7,460 million, compared with $6,924 million at March 31, 2007. The increase was a result of long term bond issues totaling $830 million, an increase in revolving borrowings of $157 million, an addition of approximately $145 million of transaction costs, premiums and discounts which have been reclassified to long-term debt to reflect the adopted policy of capitalizing long-term debt transaction costs, premiums and discounts within long-term debt, and withdrawals of $143 million in sinking funds. These increases were partially offset by $541 million of bond maturities and foreign exchange gains of $196 million.

Property, Plant and Equipment Expenditures

Property, plant and equipment expenditures were as follows:

(in millions)	For the three months ended December 31[1]		For the nine months ended December 31[1]	
	2007	2006	2007	2006
Distribution improvements and expansion	$ 109	$ 68	$ 274	$ 213
Generation replacements and expansion	89	55	226	126
Transmission lines and substation replacements & expansion	68	65	202	173
General, including computers and vehicles	21	12	64	28
Property, plant and equipment expenditures	$ 287	$ 200	$ 766	$ 540

1 Excludes intangible assets

The increase in distribution improvements and expansion capital expenditures for the three month period ended December 31, 2007 is primarily due to system resiliency work and customer driven growth projects including Olympic venues in the lower mainland. Generation replacements and expansion expenditures has increased mainly due to significant improvement projects including the Revelstoke Unit 5 turbine installation and the Aberfeldie Redevelopment project. The slight increase in transmission activities is primarily from work on the Vancouver Island Transmission connection and the Mission Matsqui Reinforcement project. The increase in general expenditures is primarily due to building redevelopment work.

The increase in distribution improvements and expansion capital expenditures for the nine month period ended December 31, 2007 is primarily due to system resiliency and system improvement projects as well as customer driven growth projects including Olympic venues in the lower mainland. Generation replacements and expansion expenditures has increased mainly due to several significant improvement projects including the Revelstoke Unit 5 turbine installation, the Aberfeldie Redevelopment project, the Campbell River Ladore and the GM Shrum stator and rotor pole replacements. The increase in transmission activity is primarily due to the Vancouver Island Transmission and Mission Matsqui Reinforcement projects. The increase in general expenditures is primarily due to the purchase of new properties and building redevelopment work.

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 acceptable levels which are commensurate with potential benefits to be derived. While risks cannot be eliminated, BC Hydro's strategies aim to minimize or mitigate them with a specific 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 overseeing the identification and assessment of significant risks and ensuring 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.

Financial

BC Hydro electricity generating facilities continue to have high reservoir levels, providing BC Hydro with increased operating flexibility and allowing them to better mitigate the impacts of potentially volatile market energy prices for the remainder of fiscal 2008. However, despite the higher reservoir levels, additional electricity supplies will continue to be required to meet peak demand periods that typically occur during the coldest winter days in November through February.

This supply requirement has also been accentuated by increasing domestic load growth from BC Hydro customers and a widening gap between the domestic electricity supply and demand. The growth in electricity demand is a result of the strong provincial economy in British Columbia, despite the continued downturn in certain segments of the forestry industry

BC Hydro is also exposed to financial risk, such as changes in interest rates or foreign exchange rates. During the third quarter those financial risks were relatively stable. Management's assessment of risk is ongoing. Other risks to BC Hydro have not changed materially from the Management Discussion and Analysis in the 2007 Annual Report.

Future Outlook (Draft)

The Budget Transparency and Accountability Act requires that BC Hydro file a Service Plan each February. BC Hydro's Service Plan filed in February 2007 indicated that income before regulatory accounts for this year was forecast at $324 million and net income forecast at $365 million. BC Hydro prepared an updated forecast in January 2008 that forecasts income before regulatory accounts of $431 million and net income of $370 million for fiscal 2008.

BC Hydro's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, weather temperatures, interest rates and foreign exchange rates. The January forecast update assumes water inflows return to normal levels, resulting in an average annual rate of 109 per cent, customer load of 53,587 GWh, average market energy prices of US $52.10/MWh, a moderate increase in operating costs, short-term interest rates of 4.45 per cent and a U.S. dollar exchange rate of US $0.9749.

In the current updated forecast the estimated cumulative rate increase for fiscal 2009 to 2010 will be 15.3 per cent. To assist customers in mitigating and potentially offsetting the impact of future rate increases, BC Hydro will be actively promoting Power Smart programs and other conservation habits that will help reduce energy consumption. The estimated rate increases are higher largely due to an anticipated increase in Government levies (largely property taxes and water rental rates), higher finance charges arising from an increase in forecasted interest rates, and an increase in operating costs needed to support the execution of key initiatives to service and maintain an aging infrastructure. The forecast rate increases are indicative only and have not been approved by the BCUC. The forecast rate increases are subject to change given the volatility around several assumptions including water inflows and market prices for energy.

CONSOLIDATED STATEMENT OF OPERATIONS

(Unaudited)	For the three months ended December 31		For the nine months ended December 31	
(in millions)	2007	2006	2007	2006
Revenues				
Domestic	$ 774	$ 724	$ 2,106	$ 1,965
Trade	464	388	1,401	1,097
	$1,238	1,112	$ 3,507	$ 3,062
Expenses				
Energy costs:				
Domestic	210	273	582	796
Trade	439	264	1,240	739
Operations	75	67	200	181
Maintenance	84	86	222	208
Administration	31	31	76	98
Taxes	38	36	116	111
Amortization	86	83	267	280
	963	840	2,703	2,413
Operating Income	275	272	804	649
Finance charges	(116)	(129)	(348)	(344)
Income Before Regulatory Account Transfers	159	143	456	305
Net change in regulatory accounts (note 4)	29	33	(106)	75
Net Income	$ 188	$ 176	$ 350	$ 380

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(Unaudited)	For the three months ended December 31		For the nine months ended December 31	
(in millions)	2007	2006	2007	2006
Net Income	$ 188	$ 176	$ 350	$ 380
Other Comprehensive Income (note 6)	15	–	81	–
Comprehensive Income	$ 203	176	$ 431	380

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEET

(Unaudited) *(in millions)*	**As at December 31** 2007	**As at March 31** 2007
ASSETS		
Property, Plant and Equipment, net	$ 10,495	$ 10,002
Current Assets		
Cash and cash equivalents	38	8
Current portion of sinking funds	502	130
Accounts receivable and accrued revenue	569	512
Materials and supplies	172	137
Prepaid expenses	27	110
Mark-to-market gains	93	61
	1,401	958
Other Assets and Deferred Charges		
Intangible assets	418	424
Sinking funds	84	603
Regulatory assets (note 4)	734	874
	1,236	1,901
	$ 13,132	$ 12,861
LIABILITIES AND EQUITY		
Long-term debt net of sinking funds	$ 6,874	$ 5,632
Sinking funds presented as assets	84	603
Long-Term Debt	6,958	6,235
Current Liabilities		
Current portion of long-term debt, net of short-term sinking fund	586	1,292
Current portion of sinking funds presented as assets	502	130
Current portion of long-term debt	1,088	1,422
Accounts payable and accrued liabilities	1,104	1,267
Mark-to-market losses	234	43
	1,338	1,310
Other Liabilities		
Regulatory liabilities (note 4)	412	429
Deferred contributions	968	913
Debt issue and related costs (note 2)	–	145
Other long-term liabilities	455	459
Foreign currency contracts (note 2)	–	165
	1,835	2,111
Shareholder's Equity (note 6)	1,913	1,783
	$ 13,132	$ 12,861

Commitments and Contingencies (note 7)

See accompanying notes to the interim consolidated financial statements.

Approved on behalf of the Board:

Mossadiq S. Umedaly
Chair

W.C. (Wanda) Costuros
Chair, Audit and Risk Management Committee

CONSOLIDATED STATEMENT OF CASH FLOWS

(Unaudited)	**For the three months ended December 31**		**For the nine months ended December 31**	
(in millions)	2007	2006	2007	2006
Operating Activities				
Net income	$ 188	$ 176	$ 350	$ 380
Regulatory account transfers	(53)	(82)	42	(179)
Adjustments for non-cash items:				
Amortization of regulatory accounts	24	48	64	104
Amortization expense	86	83	267	280
Foreign exchange translation (gains) losses	(1)	7	(23)	(1)
Deferred revenue	16	24	23	24
Amortization of debt issue and related costs	(1)	(2)	(3)	(7)
Unrealized (gains) losses on mark-to-market	28	(54)	9	(86)
Sinking fund income	(9)	(8)	(19)	(28)
Employee benefit plan expenses	-	7	-	22
Other non-cash items	10	3	18	12
	288	202	728	521
Working capital changes	8	(80)	(143)	(235)
Cash provided by operating activities	296	122	585	286
Investing Activities				
Property, plant and equipment expenditures	(297)	(199)	(787)	(549)
Deferred contributions	28	16	78	67
Other items	(2)	(1)	(10)	(10)
Cash used for investing activities	(271)	(184)	(719)	(492)
Financing Activities				
Bonds:				
Issued	–	–	830	300
Retired	–	(526)	(541)	(526)
Revolving borrowings	4	467	157	495
Sinking fund withdrawals	–	147	143	148
Deferred debt costs	–	–	–	27
Settlement of derivative instruments	–	–	(94)	–
Payment to the Province	–	–	(331)	(223)
Cash provided by financing activities	4	88	164	221
Increase in cash and cash equivalents	29	26	30	15
Cash and cash equivalents, beginning of period	9	12	8	23
Cash and cash equivalents, end of period	38	38	38	$ 38
Supplemental disclosure of cash flow information				
Interest paid	$ 140	$ 132	$ 392	$ 386

See accompanying notes to the interim consolidated financial statements

NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED) DECEMBER 31, 2007

Description

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, distribute and supply power. BC Hydro's corporate purpose is to provide "Reliable power, at low cost, for generations." 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.

BC Hydro owns and operates electric generation and distribution facilities in the Province. BC Hydro also owns transmission facilities in the Province that are operated by British Columbia Transmission Corporation (BCTC), an independent Crown corporation of the Province.

Note 1: Accounting Policies

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 2007 Annual Report.

Except for as noted below in note 2, these interim consolidated financial statements follow the same accounting policies as those described in BC Hydro's 2007 Annual Report.

Certain figures for the previous period have been reclassified to conform to presentation in the current period.

Note 2: Adoption of New Accounting Policy

On April 1, 2007, BC Hydro adopted four new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Handbook Section 1530, Comprehensive Income, Handbook Section 3855, Financial Instruments – Recognition and Measurement, Handbook Section 3861, Financial Instruments – Disclosure and Presentation, and Handbook Section 3865, Hedges. BC Hydro adopted these standards retroactively with an adjustment of opening retained earnings and accumulated other comprehensive income; accordingly, comparative amounts for prior periods have not been restated.

Comprehensive Income

As a result of adopting these standards a new category, accumulated other comprehensive income (AOCI), was added to shareholder's equity. Comprehensive income consists of net income and other comprehensive income (OCI). OCI represents changes in shareholder's equity during a period arising from transactions and changes in the fair value of available for sale securities and the effective portion of cash flow hedging instruments. Amounts are recorded in OCI until the criteria for recognition in the consolidated statement of operations are met.

Financial Instruments – Recognition and Measurement

Section 3855 establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the standard. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading. For other financial instruments, transaction costs are capitalized on initial recognition.

Financial assets and financial liabilities held-for-trading are measured at fair value with changes in those fair values recognized in income. Financial assets classified as "available-for-sale" are measured at fair value, with changes in those fair values recognized in OCI. Financial assets and liabilities classified as held-to-maturity are measured at amortized cost using the effective interest method of amortization. All derivatives, including embedded derivatives that are not closely related to the host contract and must be separately accounted for, generally must be classified as held-for-trading and recorded at fair value in the consolidated balance sheet. BC Hydro has selected April 1, 2003 as the transition date for recognizing embedded derivatives and, therefore, recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired, or substantially modified on or after April 1, 2003. All regular-way purchases or sales of financial assets are accounted for on a settlement date basis.

Hedges

Section 3865 expands the guidelines provided in Accounting Guideline 13, Hedging Relationships, by specifying the criteria that must be satisfied in order for hedge accounting to be applied and the accounting for fair value hedges and cash flow hedges. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for unrealized gains or losses attributable to the hedged risk and recognized in net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net income. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income. The ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item.

Impact upon Adoption

The transition adjustments attributable to the re-measurement of financial assets and financial liabilities at fair value were recognized in retained earnings as at April 1, 2007. Adjustments arising from re-measuring financial assets classified as available-for-sale or from the effective portion of derivatives designated as cash flow hedges at fair value were recognized in opening AOCI as at April 1, 2007.

The transition amounts that were recorded in the opening retained earnings or in the opening accumulated other comprehensive income balance on April 1, 2007 were as follows:

(in millions)	Opening Retained Earnings	Opening Accumulated Other Comprehensive Income
Change in accounting policy from the straight line method to the effective interest method for amortization	$ (6)	$ –
Opening ineffective portion of fair value hedges	7	–
Fair value adjustment upon reclassification of sinking funds to available-for-sale	–	1
Opening fair value adjustment of cash flow hedges	–	(21)
Transition Adjustments	$ 1	$ (20)

With the adoption of Section 3855, $145 million of transaction costs, premiums and discounts have been reclassified to long-term debt from debt issue and related costs to reflect the adopted policy of capitalizing long-term debt transaction costs, premiums and discounts within long-term debt. The costs capitalized within long-term debt will be amortized using the effective interest method. BC Hydro's policy is to recognize transaction costs associated with financial assets and liabilities, that are classified as other than held-for-trading, as an adjustment to the cost of those financial assets and liabilities recorded in the balance sheet. These transaction costs are amortized into earnings using the effective interest rate method over the life of the related financial instrument. Previously, BC Hydro deferred these costs within other assets and amortized them straight-line over the life of the related long-term debt.

The following table provides a comparison of carrying values for non-derivative financial instruments as at December 31, 2007, and March 31, 2007:

	December 31, 2007		**March 31, 2007**	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Held-for-Trading:				
Cash and cash equivalents	$ 38	$ 38	$ 8	$ 8
Revolving borrowings – Cdn	(994)	(994)	(826)	(826)
Revolving borrowings – US	–	–	(10)	(10)
Loans and Receivables:				
Accounts receivable	502	502	509	512
Available-for-Sale:				
Sinking funds – Cdn	502	502	509	512
Sinking funds – US	–	–	129	127
Held-to-Maturity:				
Sinking funds – US	84	90	95	97
Other Financial Liabilities:				
Accounts payable and accrued liabilities	1,104	1,104	1,267	1,267
Long-Term Debt	(7,052)	(8,138)	(6,821)	(8,075)

For assets classified as held-for-trading, no amount has been recognized in net income for the period relating to changes in fair value. For loans and receivables, the carrying value approximates fair value and amortized cost due to the short term nature of these financial instruments. For available-for-sale financial assets, $3.7 million has been recorded in other comprehensive income and $3.0 million was removed from other comprehensive income and reported in net income for the period.

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

	December 31, 2007		**March 31, 2007**	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Designated Hedges:				
Foreign currency contracts	$ (178)	$ (178)	$ (165)	$ (167)
Interest rate swaps	24	24	–	8
Commodity derivatives	–	–	–	(13)
Non-designated Hedges				
Foreign currency contracts	(2)	(2)	–	–
Interest rate swaps	–	–	NIL	NIL
Commodity derivatives	5	5	17	14

For the three and nine months ended December 31, 2007, no net gain or loss was recognized in operations related to the ineffective portion of designated cash flow hedges and fair value hedges. For designated cash flow hedges for the three and nine months ended December 31, 2007, a gain of $2 million and a loss of $96 million was recognized in other comprehensive income and $9 million and $178 million was removed from other comprehensive income and reported in net income, offsetting foreign exchange gains recorded during the period.

For derivatives not designated as hedging instruments, $1 million and $10 million were recognized in other revenue for the three and nine months ended December 31, 2007. Another $1 million was recognized in finance charges and $9 million and $5 million was recorded in trading revenue for the three and nine months ended December 31, 2007. Using the effective interest rate method, charges for the three and nine months ended December 31, 2007 were $1 million and $3 million higher than the straight-line depreciation method that would previously have been used.

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. Calculation of its revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

BC Hydro applies various accounting policies that differ from GAAP for enterprises that do not operate in a rate-regulated environment. Generally, these policies result in deferral and amortization of costs and recoveries to allow for adjustment of future rates. In the absence of rate-regulation, these amounts would otherwise be included in the determination of net income in the year the amounts are incurred. These accounting policies support BC Hydro's regulation and have been established through ongoing application by approval of the BCUC.

During the first quarter BC Hydro requested and received regulatory approval, subject to a cost prudence review, for the establishment of the F2007 Unplanned Major Storm Restoration Costs regulatory account, which is included in Other Regulatory Accounts. BC Hydro also received BCUC approval to include in this account certain expenditures incurred in fiscal 2008 related to improving outage communication and system resiliency.

Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. For the nine months ended December 31, 2007, the impact of regulatory accounting has resulted in a decrease to net income of $106 million (2006 – $75 million increase).

(in millions)	April 1, 2007	Accounting Policy Change	Addition (Reduction)	Amortization	Net change	September 30, 2007
Regulatory Assets						
Heritage Deferral Account	$ 178	$ –	$ (64)	$ (36)	$ (100)	$ 78
Non-Heritage Deferral Account	209	–	(55)	(42)	(97)	112
BCTC Deferral Account	13	–	13	(3)	10	23
Demand-Side Management Programs	282	–	39	(27)	12	294
First Nation Negotiations, Litigation and Settlement Costs	122	–	9	(2)	7	129
Other Regulatory Accounts	70	–	22	6	28	98
Total Regulatory Assets	$ 874	$ –	$ (36)	$ (104)	$ (140)	$ 734
Regulatory Liabilities						
Future Removal and Site Restoration Costs	$ 210	$ –	$ –	$ (11)	$ (11)	$ 199
Trade Income Deferral	203	–	(17)	(41)	(58)	145
Foreign Exchange Gains and Losses	16	17	23	12	35	68
Total Regulatory Liabilities	$ 429	$ 17	$ 6	$ (40)	($34)	$ 412
Net	$ 445	$ (17)	$ (42)	$ (64)	$ (106)	$ 322

With the adoption of Section 3855 certain financial instruments that had previously been deferred as part of the Foreign Exchange Gains and Losses regulatory account have been reclassified to Mark-to-market gains.

Note 5: Employee Future Benefits

BC Hydro's cost for employee future benefits for the three and nine months ended December 31, 2007 was $11 million and $32 million respectively (2006 – $17 million and $52 million).

Note 6: Shareholder's Equity

Consolidated Statement of Comprehensive Income

	For the three months ended December 31		For the nine months ended December 31	
(in millions)	2007	2006	2007	2006
Other Comprehensive Income				
Unrealized gain (loss) on sinking fund balances	3		(4)	
Reclassification to income of loss on sinking funds	1	–	3	–
Unrealized loss on derivatives designated as cash flow hedges	2	–	(96)	–
Reclassification to income of loss on derivatives designated as cash flow hedge	9	–	178	–
Other Comprehensive Income	15	–	81	–

Statement of Shareholder's Equity

	For the nine months ended December 31	
(in millions)	2007	2006
Retained earnings, beginning of period	$ 1,783	1,707
Change in accounting policy (note 2)	1	–
Net income	350	380
Accrued Payment to the Province	(282)	(312)
Retained earnings, end of period	$ 1,852	$ 1,775
Accumulated other comprehensive income, beginning of period	–	–
Transition adjustment upon change in accounting policy (note 2)	(20)	–
Other comprehensive income for the period	81	–
Accumulated other comprehensive income, end of period	61	–
Shareholder's Equity	$ 1,913	$ 1,775

Note 7: Commitments and Contingencies

Long-term Energy Purchase Contract

On August 16, 2007, BC Hydro entered into a revised long-term energy purchase contract with Alcan Inc., replacing the November 1, 2006 agreement rejected by the BCUC. The revised contract was submitted to the BCUC for approval and was approved on January 29, 2008 (see note 8). Energy purchases under the new contract commenced during the third quarter and will continue until December 31, 2034.

Powerex Legal Proceedings

Since 2000, Powerex has been named, along with other energy providers, in a number of 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. These proceedings are at various stages.

The U.S. Court of Appeals for the Ninth Circuit has remanded back to the U.S. Federal Energy Regulatory Commission (FERC) the Lockyer case with instructions that FERC should reconsider its remedial powers thereby opening up the possibility that refunds will have to be paid for energy sales during the period May to October 2000. In other cases, the Ninth Circuit has issued conflicting decisions on whether refunds should be paid relating to bilateral sales. It rejected

FERC's categorical exclusion of bilateral purchases and remanded one case back to FERC opening up the possibility that Powerex would have to pay refunds for energy sales during the period January to June 2001. Powerex is seeking rehearing of that decision. As it relates to the period from October to December 2000, FERC has already decided that refunds will have to be paid but the precise amount has not been determined.

At December 31, 2007, Powerex was owed US $268 million (CDN $265 million) by the markets operated by the California Power Exchange (Cal Px) and the California Independent System Operator (CISO) related to Powerex's electricity trade activities in California during the period covered by the lawsuits. As a result of defaults by a number of California utilities, the Cal Px and CISO were unable to pay these amounts to Powerex. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

FERC has approved a settlement agreement between FERC staff and Powerex that acknowledged that there was no evidence that Powerex engaged in any gaming practices or concerted partnership practices with any other market participants, and further noted that Powerex was a valuable and reliable supplier to the California market throughout the energy crisis. FERC has not issued a final order in that settlement.

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.

Note 8: Subsequent Events

On January 29, 2008 a decision was issued by the BCUC approving the long-term energy purchase contract between BC Hydro and Alcan Inc. The contract provides BC Hydro with the exclusive rights to capacity and energy not required to serve the Kitimat Smelter Load from the Kemano Powerhouse located on the Nechako Reservoir. Delivery under the contract occurred effective October 1, 2007 but was subject to cancellation if the decision from the BCUC was not obtained prior to the January 31, 2008 deadline. The approval from the BCUC is in compliance with this deadline and finalizes the terms of the contract.

FOR GENERATIONS

GDS08-025 February 08