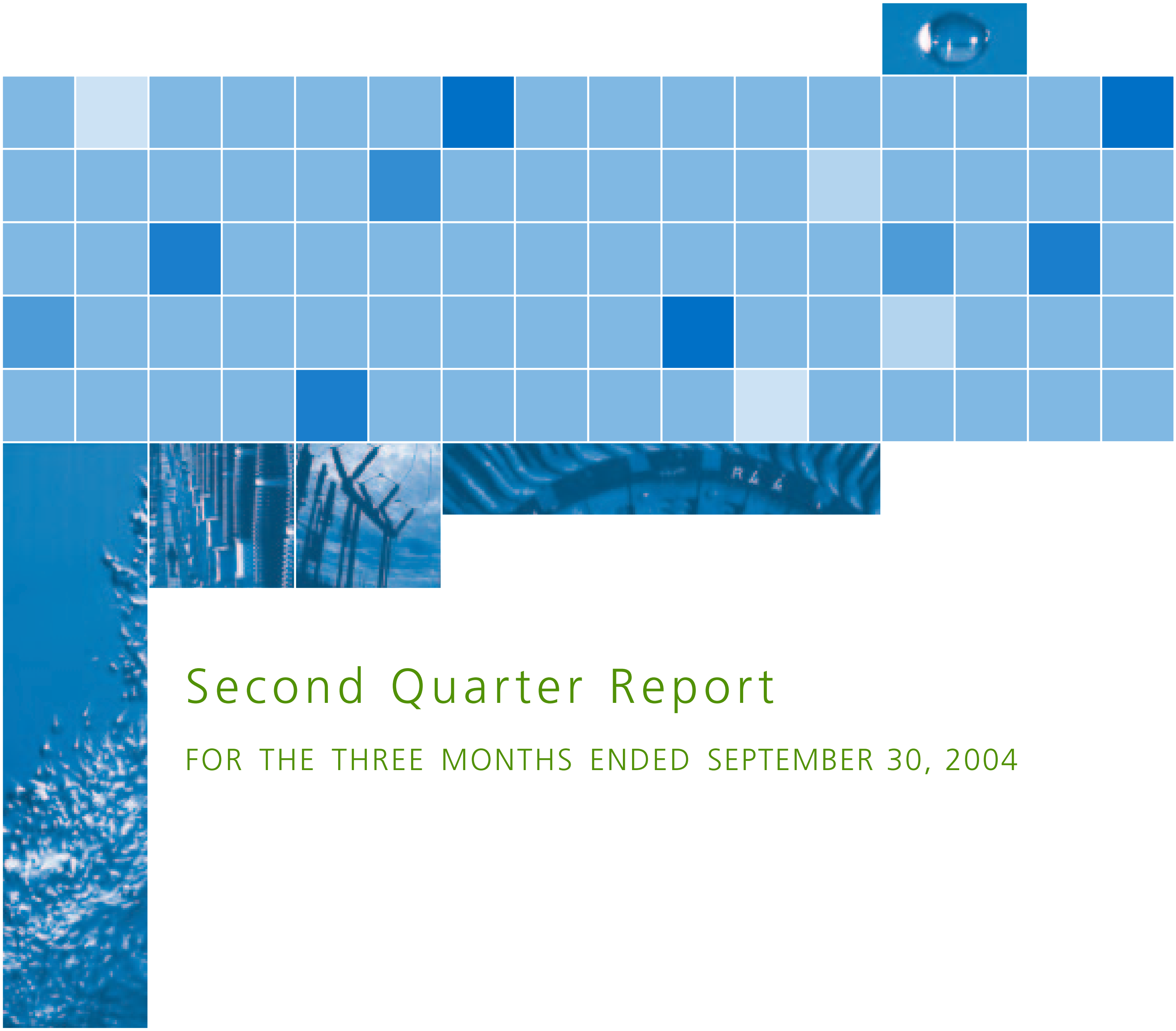

Second Quarter Report

FOR THE THREE MONTHS ENDED SEPTEMBER 30, 2004

BC hydro

LG04-94

Second Quarter Report

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1. Overview

KEY HIGHLIGHTS

Financial

Income before deferral account transfers for the three months ended September 30, 2004, was $11 million compared with income of $39 million for the same period last year. The primary reason for the decrease in income was an increase in energy costs as a result of lower-than-average water inflows experienced this year. Market purchases of electricity have increased to compensate for the lower inflows and to maintain reservoir levels. These increased energy costs more than offset the higher revenue that resulted from the interim 7.23 per cent rate increase that was approved by the B.C. Utilities Commission effective April 1, 2004.

After deferral account transfers, net income is $92 million for the three months ended September 30, compared with $39 million for the same period last year. A significant portion of the increased energy costs is transferred to the deferral accounts, which is a major consideration in the year-over-year net income performance.

Income before deferral account transfers for the six months ended September 30, 2004, was $19 million, compared with income of $39 million for the same period last year. After deferral account transfers, net income is $144 million for the six months ended September 30, compared with $39 million for the same period last year. The increased energy costs in the current year, and the related transfer of a significant portion of that cost increase to the deferral accounts, was the primary reason for the increase in net income.

BC Hydro's forecast income before deferral account transfers for fiscal 2005 is approximately $240 million. The forecast of $240 million is a $35 million reduction from the forecast disclosed in the quarterly report for the three months ended June 30, 2004. The forecast includes the rate increase sought in the Revenue Requirements Application, consisting of the interim rate increase of 7.23 per cent effective April 1, 2004, and a further 1.67 per cent to be effective when approved by the Commission. If the Commission does not approve the full amount of the interim increase, the difference will be fully refunded to customers with interest. A final decision from the Commission is expected in the fall of 2004.

The $35 million reduction in forecast income before deferral accounts from the first quarter report is largely due to an increase in energy purchases as a result of continued below-average water inflows and reservoir levels.

The purpose of the deferral accounts, as detailed in the notes to the financial statements, is to mitigate the impact of certain variances between actual and forecast costs of service. After taking the deferral accounts into consideration, the current forecast net income for fiscal 2005 is $424 million, compared with $447 million in the forecast in the report for the three months ended June 30, 2004.

Performance Plan

BC Hydro had a successful second quarter as reflected in its performance measures. Six of the seven corporate measures either met (3) or exceeded (3) their quarterly targets. For more information on corporate measures, see "Performance Measures – BC Hydro Overall."

System Operations

BC Hydro manages the levels at its hydroelectric reservoirs to ensure the most efficient use of stored water to meet domestic load and to maximize value creation through electricity trade. Terms of the water licences and treaty requirements are factors in this process. Reservoir levels at any time are a function of inflows (caused by snowmelt and/or rainfall runoff) and electricity demand (as water in the reservoirs is discharged through turbines to produce electricity).

Above-average rainfall in the region during the later part of August and September, combined with the strategic use of market purchases, has improved reservoir inflows. The system storage position is now approximately 2,000 GWh below normal.

KEY HIGHLIGHTS

The February to September 2004 system weighted inflow was 90 per cent of average. These reduced water inflows have resulted in increased market electricity purchases in the current year to maintain a better balance in the reservoirs.

Resource Acquisition

BC Clean Energy

The BC Clean Energy target (50 per cent of incremental load) is being met with committed efficiency improvements and acquisitions pursuant to calls for Customer-Based Generation and Green Power issued in 2002. As part of its commitment to meet the 50 per cent BC Clean Energy target, 394 GWh of clean energy has been delivered to BC Hydro for the six months to September 30.

Vancouver Island Call For Tenders

The Vancouver Island Call for Tenders (VICFT) issued on October 31, 2003, for capacity and associated energy supply on Vancouver Island is on track to produce an outcome of between 150 MW to 300 MW of supply options. Of the 23 bidders who originally registered to participate in the CFT process, 11 bidders were pre-qualified to submit tenders, which were due on August 13, 2004. Tenders have been evaluated, which resulted in a preferred supply option and the outcome will be announced at the end of October, followed by submission of the final documents to the BCUC in November 2004.

Achievements

BC Hydro's Power Smart initiative met the cumulative energy savings target of 1,100 GWh for the second quarter in the third year of the Power Smart 10-year Plan (total 10-Year Plan goal is for over 3,600 GWh), providing for approximately 35 per cent of new load growth over the same three-year time period.

A Large Project Incentive Program was introduced during the quarter and is an enhancement to the existing Power Smart Partner program (BC Hydro's largest business customers who commit to improve energy efficiency by five per cent). The program is designed to help Partners who implement large energy efficiency and self-generated load displacement projects and is available to all Power Smart Partners who have projects that require incentives of more than $1 million. The first milestone, the deadline for pre-qualification submissions for the call, was October 4, 2004. The second customer milestone is November 30, where pre-qualified customers will respond to the formal RFP. The call is for up to 375 GWh, to be in place by March 2007.

Year-to-date net new customer additions totalled 11,567, an increase of 10 per cent over the same period last year. This upward trend is expected to continue for the remainder of the fiscal year, due to the general strength of the economy.

Accenture Business Services for Utilities is responsible for the performance of all Customer Care functions. There are 13 critical service levels, which are measures of this performance, and for the second quarter, eight of these measures have been met or exceeded and four were still under review and not being reported.

BC Hydro continues to receive service on most of the defined metrics at the levels received prior to the outsourcing agreement, and in some cases, service has exceeded past levels. Financially, the contract is ahead of target. Spending at the end of the second quarter was $69.6 million: 4.7 per cent lower than planned. The majority of this variance was due to lower spending in Information Technology services.

Customer satisfaction with Call Centre transactions is measured by a survey of residential and commercial customers who have completed a recent transaction with the Call Centres. This telephone survey is conducted by an independent third party on a weekly basis and the results aggregated for the month. The satisfaction level for the year-to-date average to September 30 was 88.5 per cent, well above the target of 84 per cent.

The BC Hydro Board of Directors has approved in principle a proposal to acquire the interests in the power projects owned jointly by the Columbia Basin Trust and Columbia Power Corporation (CPC). The acquisition by BC Hydro would involve acquiring three hydroelectric facilities and one project in development in the Columbia River Basin. Two of the three facilities are operating (Brilliant and Arrow Lakes), one is under construction (Brilliant Expansion) and the fourth is the proposed Waneta Expansion. BC Hydro is conducting a due diligence review over the next three months. The results of that review will be considered by the BC Hydro Board of Directors prior to final approval.

British Columbia Transmission Corporation (BCTC) filed its application for approval of British Columbia Transmission Corporation Standards of Conduct with the British Columbia Utilities Commission on September 22. The proposed Standards of Conduct are a necessary element of the provision of non-discriminatory open access transmission service in B.C. The Standards of Conduct reflect the fact that BCTC operates as an independent transmission company and is now separate from BC Hydro.

Challenges

A BC Hydro electrician suffered fatal injuries on September 13 while performing work at the Puntledge substation on Vancouver Island. This tragic incident underscores the high hazards workers face in the electric utility industry and the need for continued focus on safety. The investigation is ongoing, with final reporting expected in October.

A heavy snowstorm began in the Peace River service region on the evening of Friday, September 17, with accumulations of 30 centimetres of heavy, wet snow. The effects of the storm were compounded as leaves were still on the trees and the weight of the snow brought down a larger-than-normal amount of vegetation onto transmission and distribution lines. Over the duration of the storm, five transmission lines suffered outages and 12 distribution feeders suffered multiple outages. Approximately 10,000 customers were impacted in Fort St. John, Chetwynd, Dawson Creek and surrounding rural areas. By 9:00 p.m. Saturday, all major distribution feeders had been repaired with power restored to approximately 75 per cent of impacted customers. By 6:00 p.m. Sunday, power had been restored to approximately 90 per cent of impacted customers. This performance is consistent with BC Hydro's aim in a storm situation to restore 75 per cent of customers in 24 hours and 90 per cent of customers in 48 hours, despite the severity of the storm.

In 2002 BC Hydro began a three-year Resource Smart program to replace the turbines in Units 6, 7 and 8 at the G.M. Shrum dam in the Peace Region to improve unit efficiency. In August 2004, Unit 7 was forced out of service due to excessive turbine vibration. Subsequent investigation determined that components of the new turbine (installed in 2002) had failed, requiring the unit to be disassembled and repaired. Units 6 and 8 have similar design deficiencies and are being disassembled to perform temporary repairs to enable these units to be operated during the winter season. They are expected to be back in service by the end of November 2004. Units 6 and 8 will be taken out of service and disassembled during fiscal 2006 to perform permanent repairs.

The U.S. Ninth Circuit Court of appeal issued a ruling in the case of California Attorney General Lockyer v. the U.S. Federal Energy Regulatory Commission (FERC). The ruling upholds the FERC's authority over its market-based rate program (and administration of Power Marketing Authorization – PMA) but orders the case of California refunds back to FERC for further consideration. It is not yet known how the FERC will respond to this order and what the implications might be for market participants, including Powerex.

2. Performance Measures

BC HYDRO OVERALL

Performance measurement is an integral part of BC Hydro's triple bottom line approach to managing the business. The Second Quarter Report reviews performance for the three-month period, July 1 to September 30, 2004. The exception is the Customer Satisfaction measure which is tracked over a six-month period, April 1 to September 30, 2004. This enables BC Hydro to better identify the effect of specific events that adversely impact performance, with a view to implementing corrective action where appropriate.

BC Hydro's Service Plan dated February 2004 outlines BC Hydro's goals and objectives, performance measures, and year-end targets. Performance results against these targets will be published in the company's 2005 Annual Report.

LEGEND (for all Performance Measures)

▲ Significantly better than target
● Meets target (within range)
▼ Significantly Below Target

Income before Deferral Account Transfers ▼
(in millions)

Annual Target – $406 million

	Actual	Target
Q2 04/05	$11	$64
Q2 03/04	$39	($52)

Income before deferral account transfers of $11 million was $53 million below plan. The primary factor was an increase in energy costs as a result of lower than average water inflows experienced this year. Market purchases of electricity have increased to compensate for the lower inflows and to maintain reservoir levels.

Reliability ●

Annual Target – 99.970%

ASAI	Actual	Target
Q2 04/05	99.968%	99.964%
Q2 03/04	99.945%	99.964%

Annual Target – 2.15 hours

CAIDI	Actual	Target
Q2 04/05	1.85 hours	2.13 hours
Q2 03/04	3.48 hours	2.13 hours

Last year's second-quarter results reflect the impact of the McLure Forest Fire, whereas fires this year did not have a significant impact on the quarterly results. Based on current results, BC Hydro expects to meet the ASAI and CAIDI year-end targets.

All Injury Frequency ●

Annual Target – 2.7

	Actual	Target
Q2 04/05	2.7	2.8
Q2 03/04	3.4	3.1

BC Hydro is witnessing a sustained rate of reduction in the current year. Despite these overall performance improvements, a fatal electrical contact incident occurred in September while tests were being performed on station equipment at Puntledge Generating Station. The employee came into contact with a high potential voltage source that had been established through parallel circuit induction. An investigation is underway, and BC Hydro will take any recommended actions to reduce the likelihood of such an incident recurring.

The company's vision remains to have zero injuries. This vision serves to keep the focus on injury reduction, irrespective of the performance excellence achieved against internal targets, as well as relative to peers in B.C. industry and among Canadian Electricity Association utilities.

Based on current results, BC Hydro expects to meet the AIF year-end target.

PERFORMANCE MEASURES — BC HYDRO OVERALL

Environmental Regulatory Compliance ▲

Annual Target – 28 incidents

	Actual	Target
Q2 04/05	3 incidents	7 incidents
Q2 03/04	6 incidents	7 incidents

Note: Fiscal 04/05 actuals and targets no longer include the British Columbia Transmission Corporation's (BCTC) externally reportable, preventable environmental incidents. Fiscal 03/04 Q2 actual and target (previously reported as actual at six incidents and target at 10 incidents) have been adjusted to remove BCTC results, for comparison purposes.

Second-quarter results are better than the apportioned annual target for this quarter and are within the normal quarter-to-quarter variability observed historically. Of the three Environmental Regulatory Compliance incidents this quarter, two were attributed to human error and one was attributed to equipment failure; none was categorized as "severe". Based on current results, BC Hydro expects to better the Environmental Regulatory Compliance measure annual target.

Conservation Gigawatt Hours ▲

Annual Target – 500 GWh

	Actual	Target
Q2 04/05	115 GWh/year	100 GWh/year
Q2 03/04	52 GWh/year	50 GWh/year

Power Smart programs are 15 GWh/year above target for the second quarter. The Industrial sector is ahead of plan at this stage due to a shift in timing of a large project. The Residential sector is also ahead of plan at this stage primarily due to higher-than-expected activity with the Refrigerator Buy-Back program and a shift in timing with the Compact Fluorescent Light program. The Commercial sector is below plan at this stage due to lower-than-anticipated activity levels: program adjustments are being initiated to close this gap.

The actual number of 115 GWh/year includes discounts for free riders, free drivers, and measurement and verification. Free riders refers to those who participate in a program but would have done so without BC Hydro's involvement; free drivers refers to those who do not participate in a program (e.g., use a coupon) but are influenced by it and proceed because of it; measurement and verification allows for energy savings that may be lower than initial estimates when actually measured.

The second-quarter actual savings are approximately double that of the second quarter last year, due to increased market opportunities resulting from momentum created over the initial years of Power Smart plan implementation. Based on current results, BC Hydro expects to meet the cumulative multi-year target of 1,310 Conservation GWh.

Approved Strategic Workforce Planning Positions Filled (SWfP) ●

Annual Target – 71

	Actual	Target
Q2 04/05	7	7
Q2 03/04	4	4

Based on current results, it is expected that the Approved Strategic Workforce Planning Positions Filled program will achieve the annual target.

Customer Satisfaction Index ▲

Annual Target – 84%

	Actual	Target
Q2 04/05	89%	84%
Q2 03/04	90%	84%

Customer Satisfaction is a composite indicator. Thirty per cent of the measure comes from a survey using all customers as the population from which to draw a random sample (Q2 04/05 result = 86%). The other 70 per cent comes from transactional surveys using only customers who have had a service interaction with BC Hydro as the population from which to draw a sample. Satisfied customers are those who indicate they are either "satisfied" or "very satisfied" (Q2 04/05 result = 90%).

PERFORMANCE MEASURES — BC HYDRO OVERALL

Greenhouse Gas Emissions

BC Hydro emits greenhouse gas emissions from its thermal generating plants, vehicles, buildings and some equipment. Some of BC Hydro's Independent Power Producers and import sources of electricity also emit greenhouse gas emissions. BC Hydro avoids greenhouse gas emissions by avoiding new load through Power Smart, increasing the generating efficiency of existing plants through Resource Smart, and purchasing and exporting BC Clean Electricity. BC Hydro also directly offsets the greenhouse gas emissions from some plants.

For the quarter ended September 30, 2004, greenhouse gas emissions attributable to the electricity supplied to customers in B.C. are estimated* at 0.88 million tonnes CO_2e**, or 52 tonnes CO_2e per gigawatt hour (GWh). The emissions intensity of BC Hydro's electricity fluctuates seasonally and annually with the supply of water to its reservoirs and the status of the electricity market.

Total GHG emissions were 0.32 tonnes CO_2e lower for the second quarter compared with the first quarter, mainly due to decreased imports and thermal facility operations.

Emissions (Millions of tonnes CO_2)

	F2005 Q1	F2005 Q2
Emissions If No Action Taken	**2.03**	**1.57**
Avoided Emissions		
Customer efficiency programs	0.39	0.30
Purchase of cleaner power***	0.25	0.18
Internal efficiency improvements	0.13	0.12
Net electricity exports	0.00	0.00
Total	**0.77**	**0.60**
Actual Emissions		
BC Hydro facilities	0.08	0.13
Independent Power Producers	0.26	0.29
Net electricity imports	0.92	0.55
Total	**1.26**	**0.97**
Offsets		
Island Cogeneration Project	**0.06**	**0.09**
Total	**1.20**	**0.88**
GHG intensity (t/GWh)	**96**	**52**

* Based on actuals for July and August and estimates for September for most emission sources.
** CO_2e or Carbon Dioxide equivalent tonne is a universal unit of measure for greenhouse gas emissions.
*** Net of sales of Green Power Certificates.

3. Financial

MANAGEMENT DISCUSSION AND ANALYSIS

The Management Discussion and Analysis reports on BC Hydro's consolidated results and financial position. This discussion should be read in conjunction with the Management Discussion and Analysis presented in the 2004 Annual Report, the 2004 Annual Consolidated Financial Statements of BC Hydro and the interim consolidated financial statements of BC Hydro for the three and six months ended September 30, 2004 and 2003. 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 materially from those contemplated in the forward-looking statements.

Consolidated Results of Operations

Income before deferral account transfers of $11 million for the three months ended September 30, 2004, compares with $39 million in the same period in the previous year. The primary reason for the decrease in income was an increase in energy costs as a result of lower than average water inflows experienced this year. Market purchases of electricity have increased to compensate for the lower inflows and to maintain reservoir levels. Increased energy costs more than offset the higher revenue that resulted from the interim 7.23 per cent rate increase that was approved by the B.C. Utilities Commission effective April 1, 2004. Also contributing to the decrease in income before deferral accounts was an increase in amortization expense of $9 million. Offsetting these unfavourable variances are a decrease in operations, maintenance and administration expenditures of $16 million and a decrease in finance charges of $18 million.

Net income after deferral accounts transfers is $92 million for the three months ended September 30, 2004 compared to $39 million in the same period in the previous year. A significant portion of the increased energy costs is transferred to the deferral accounts, which is a major consideration in the year-over-year net income performance.

Income of $19 million before deferral account transfers for the six months ended September 30, 2004, compares with $39 million in the same period in the previous year. The impact of increased energy costs due to below-average water inflows has more than offset the favourable impact of demand growth and the interim rate increase. Also contributing to the decrease in net income was an increase in amortization expense of $19 million. Offsetting these unfavourable variances are a decrease in operations, maintenance and administration of $28 million and a decrease in finance charges of $4 million.

Net income after deferral accounts of $144 million for the six months ended September 30, 2004, compares with $39 million in the same six-month period in the previous year. A significant portion of the increased energy costs is transferred to the deferral accounts, which is a major consideration in the year-over-year net income performance.

OPERATING HIGHLIGHTS

	For the Three Months Ended September 30		*For the Six Months Ended September 30*	
in gigawatt hours	**2004**	2003	**2004**	2003
Electricity Sold				
Residential	**2,938**	2,895	**6,205**	6,244
Light industrial and commercial	**4,260**	4,172	**8,397**	8,258
Large industrial	**4,040**	3,756	**8,037**	7,533
Other energy sales	**356**	359	**656**	640
	11,594	**11,182**	**23,295**	**22,675**
Electricity trade	**8,397**	8,500	**15,303**	16,152
	19,991	**19,682**	**38,598**	**38,827**

Domestic Revenues

Domestic revenues of $616 million for the three months ended September 30, 2004, were $51 million higher than the same period in the previous year. This increase is due to the 7.23 per cent interim rate increase effective April 1, 2004, and increased consumption, primarily in the large industrial sector as activity levels have increased in certain resource-based sectors in the province.

Domestic revenues of $1,248 million for the six months ended September 30, 2004 were $100 million higher than in the same period in the previous year. Key factors in this increase are the 7.23 per cent interim rate increase effective April 1, 2004, and growth in domestic demand of 2.7 per cent compared with the first six months of the previous year. A significant portion of this increased consumption is in the large industrial sector.

Electricity Trade Revenues

BC Hydro's electricity system is interconnected with systems in Alberta and the western United States. This interconnection facilitates sales and purchases of electricity outside of British Columbia. Electricity trade activities are carried out by Powerex, a wholly owned subsidiary of BC Hydro. While it engages in electricity trade, BC Hydro ensures that its ability to meet domestic requirements is not put under undue risk as a result of these transactions. Electricity 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 that domestic demand requirements can be met. Electricity trade revenues also include natural gas sales related to thermal generation requirements.

Net electricity trade revenues for the three months ended September 30, 2004, were $282 million, compared with $283 million in the same period in the prior year. The decrease was due to a reduction in sales volumes. The average sales price of $67/MWh this quarter was equal to the average sales price in the same period last year.

Net electricity trade revenues for the six months ended September 30, 2004, were $468 million, a decrease of $14 million from the same period in the prior year. The decrease was due to a five per cent reduction in sales volumes to 15,303 GWh in the six months ended September 30, 2004, from 16,152 GWh in the same period last year. The effect of lower sales volumes was partly offset by a three per cent increase in average sales price to $64/MWh from $62/MWh in the prior year. The increase in market prices is caused by several factors, including less energy available from low-cost hydro generation in the region and tighter natural gas supplies. The decrease in sales volumes was due primarily to lower water inflows and reservoir levels and transmission restrictions into the California market.

Energy Costs

The mix of sources of supply is impacted by variables such as the market price of energy, water inflows, reservoir levels, energy demand and environmental and social impacts.

Energy costs comprise the following sources of supply:

For the three months ended September 30	($ in millions)		(gigawatt hours)		($ per MWh)	
	2004	2003	**2004**	2003	**2004**	2003
Hydro[1]	**$ 53**	$ 60	**9,118**	10,187	**$ 5.81**	$ 5.89
Purchases from Independent Power Producers and other long-term contracts	**107**	101	**1,781**	1,722	**60.08**	58.65
Other electricity purchases[2]	**262**	160	**9,978**	8,661	**57.40**	56.77
Natural gas[3]	**47**	47	**291**	116	**85.91**	94.83
Non-integrated	**3**	3	**19**	17	**157.89**	176.47
Transmission charges and other expenses	**38**	35	–	–	–	–
Total	**$ 510**	$ 406	**21,187**	20,703	**$ 37.30**	$ 33.12

For the six months ended September 30	($ in millions)		(gigawatt hours)		($ per MWh)	
	2004	2003	**2004**	2003	**2004**	2003
Hydro[1]	**$ 101**	$ 109	**17,681**	18,829	**$ 5.71**	$ 5.78
Purchases from Independent Power Producers and other long-term purchase contracts	**184**	184	**3,006**	2,100	**61.21**	87.61
Other electricity purchases[2]	**458**	348	**19,508**	19,717	**51.86**	50.22
Natural gas[3]	**93**	85	**384**	212	**98.96**	108.49
Non-integrated	**6**	6	**41**	40	**146.34**	150.00
Transmission charges and other expenses	**74**	65	–	–	–	–
Total	**$ 916**	$ 797	**40,620**	40,898	**$ 34.60**	$ 32.15

1 Net of storage exchange due to Non-Treaty Storage Agreement with Bonneville Power Administration, Kootenay Canal Plant Agreement with Fortis BC, and Keenleyside Entitlement Agreement with Columbia Power Corporation.

2 Other electricity purchases in dollars includes purchases for trade activities shown net of derivatives. Gigawatt hours and $ per MWh are shown at gross cost.

3 Includes costs of remarketed gas of approximately $22 million for the three months ended September 30, 2004 (2003 – $36 million) and $55 miliion for the six months ended September 30, 2004 (2003 – $62 million). Remarketed gas is natural gas purchased for the purpose of resale. The volumes shown for natural gas relate only to gas used for thermal generation.

Water inflows into BC Hydro's reservoirs were three per cent lower at September 30, 2004 compared with September 30, 2003. This resulted in a reduction in reservoir levels and the volume of low-cost hydro generation. Reduced hydro generation volumes are compensated for by increased electricity imports. The decision to import energy instead of utilizing hydro generation is based on many factors, such as the forecast market price of energy in future periods relative to the current period, current reservoir levels 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.

For the three months ended September 30, 2004, energy costs of $510 million were $104 million higher than the same period in the previous year. The increase in energy costs is primarily due to electricity imports to meet domestic load requirements. For the three months ended September 30, 2004 imports were 2,130 GWh compared to 666 GWh for the same period for the previous year. Lower hydro generation in the region also increased market prices for purchased electricity.

For the six months ended September 30, 2004, energy costs of $916 million were $119 million higher than the same period in the previous year. Electricity imports for the six months ended September 30, 2004 were 4,650 GWh compared to 2,633 GWh fot the same period of the previous year. Lower hydro generation in the region also increased market prices for purchased electricity.

The combined storage in all BC Hydro reservoirs at September 30, 2004 was 98 per cent of average (2003 – 94 per cent). (Average storage levels relate to the average from 1985 to 2003). Water levels in the two largest regions, accounting for approximately 90 per cent of total storage capacity), were at 95 per cent of average (2003 – 98 per cent) for the Williston Reservoir on the Peace River system and 96 per cent of average (2003 – 81 per cent) for the Kinbasket Reservoir on the Columbia River system.

Operations, Maintenance and Administration

Total operations, maintenance and administration expenditures for the three months ended September 30, 2004, were $16 million lower than for the same period in the previous year. The primary reasons for the decrease are timing of expenditure programs compared with the same period in the previous year and the completion of major projects last year ($4 million), lower system restoration costs due to forest fires ($4 million) and lower costs associated with California power market litigation ($5 million).

Total operations, maintenance and administration expenditures for the six months ended September 30, 2004, were $28 million lower than for the same period in the previous year. The primary reasons for the decrease are timing of expenditure programs compared with the same period in the previous year and completion of major projects last year ($7 million), lower maintenance costs for thermal generation ($3 million), lower system restoration costs due to forest fires ($2 million), lower bad debt expense ($2 million) and lower costs associated with California power market litigation ($9 million).

Amortization Expense

Amortization expense for the three months ended September 30, 2004, was $9 million higher than for the same period in the previous year. For the six months ended September 30, 2004, amortization expense was $19 million higher than for the same period in the previous year. The increase in amortization expense is primarily due to increased amortization expenses for information technology projects completed in the prior year and deferred demand-side management expenditures incurred in the prior year.

Finance Charges

Finance charges for the three months ended September 30, 2004 were $18 million lower than for the same period in the previous year. The decrease in finance charges is primarily due to new accounting rules requiring mark to market accounting on risk management activities that did not meet hedge accounting criteria ($9 million), a stronger Canadian dollar compared to the US dollar ($7 million) and lower interest rates on debt refinancing ($6 million). These favourable variances were partly offset by lower sinking fund income ($3 million) and lower finance charges capitalized ($3 million).

Finance charges for the six months ended September 30, 2004 were $4 million lower than for the same period in the previous year.

Liquidity and Capital Resources

Increased market purchases of electricity were the significant factor that impacted cash flows in the periods ended September 30, 2004. Cash flow used for operating activities for the three months ended September 30, 2004 was $65 million, compared with $46 million for the same period in the previous year. Cash flow provided by operating activities for the six months ended September 30, 2004 is $150 million compared with $169 million for the same period in the previous year.

Capital expenditures, including demand-side management programs, were as follows:

	Three months ended September 30		*Six months ended September 30*	
(in millions)	**2004**	2003	**2004**	2003
Generation replacements and expansion	**$ 33**	$ 42	**$ 56**	$ 65
Transmission lines and substation replacements and expansion	**34**	55	**53**	84
Distribution improvements and expansion	**59**	46	**113**	92
General - computers, vehicles, etc.	**10**	15	**21**	41
Change in working capital related to capital asset expenditures[1]	**(4)**	4	**2**	37
Capital asset expenditures per Consolidated Statement of Cash Flows	**132**	162	**245**	319
Power Smart (Demand-side management)	**13**	11	**40**	19
Total capital expenditures per Consolidated Statement of Cash Flows	**$145**	$173	**$285**	$338

1 Adjustment from accrual to cash expenditures on the Consolidated Statement of Cash Flows

The decrease in transmission lines, substation improvements and expansion is due to timing of construction project schedules this year compared with the same period in the previous year. The increase in Distribution improvements and expansion is due to a higher volume of customer construction. The decrease in general expenditures is primarily due to the completion of a major integrated information system in the previous year. The increase in Power Smart expenditures is due to timing of incentive payments based on customer-driven project schedules.

During the six months ended September 30, 2004, BC Hydro issued $540 million of new bonds. The funds from these issues, together with an increase in revolving borrowings, were used to redeem $506 million of bonds and to fund the payment to the province and capital expenditures. The net long-term debt balance at September 30, 2004 was $6,982 million, compared with $6,900 million at March 31, 2004. The Canadian dollar at September 30, 2004 was US$0.7912, compared with US$0.7631 at March 31, 2004.

Revenue Requirement Application

On December 15, 2003 BC Hydro submitted its revenue requirement application to the British Columbia Utilities Commission (the "Commission") requesting a general rate increase of 7.23 per cent effective April 1, 2004, and a further 2.0 percent increase effective April 1, 2005. On January 23, 2004, the Commission approved the first rate increase of 7.23 per cent on an interim basis, effective April 1, 2004. On April 2, 2004, BC Hydro revised its revenue requirement application to propose a rate increase of 8.9 per cent in fiscal 2005 with no increase in fiscal 2006. The incremental rate increase of 1.67 per cent for fiscal 2005 is to become effective based on the date of approval by the Commission. A full public hearing began in May 2004 and was completed in June 2004. Subsequent to the hearing, BC Hydro and the intervenors filed final arguments with the Commission. A final decision from the Commission is expected this fall. If the Commission does not approve the full amount of the interim increase, the difference will be fully refunded to customers with interest.

Powerex Legal Proceedings

On October 31, 2003, the U.S. Federal Energy Regulatory Commission (FERC) Trial Staff cleared Powerex of allegations of inappropriate market behaviour and concluded that Powerex played a positive role in the energy market during the California energy crisis of 2000 and 2001. In the agreement, the FERC Trial Staff rejected California's claims that it was owed more than US$1 billion by Powerex, and accepted Powerex's payment of US$1.3 million "in recognition of the burdens, costs, and uncertainty associated with the litigation process, and to achieve regulatory certainty and closure." The agreement received approval from FERC and calls for further litigation to be suspended pending this approval. However, FERC's approval of the settlement is still subject to rehearing and subsequent appeal to the courts, and could also be affected by other legal proceedings relating to the California power markets, as noted below.

On September 9, 2004, the U.S. Ninth Circuit Court of Appeal issued a ruling in the case Lockyer v. the U.S. Federal Energy Regulatory Commission (FERC). This case involved FERC's dismissal of a March 20, 2002 complaint filed by California Attorney General Lockyer against Powerex and other named respondents, alleging that FERC's market-based rate program (administration of Power Marketing Authorization or PMA) was illegal or, alternatively, that FERC's failure to enforce its transaction-specific quarterly reporting requirements and sellers' failures to comply with such regulations deprived sellers of the protection of the filed rate doctrine.

In its ruling, the court stated that the FERC "abused its administrative discretion by declining to order refunds for violations" of the agency's reporting rules under the Federal Power Act, and sent the case back to FERC for further consideration.

The ruling may affect a number of issues previously decided by FERC, including Powerex's US$1.3 million FERC Settlement Agreement. Powerex and its legal counsel are closely reviewing the decision and following developments in the case to better determine the implications of the case and Powerex's response.

As was disclosed in the notes to BC Hydro's 2004 Annual Consolidated Financial Statements, Powerex still faces possible additional costs as several investigations and regulatory proceedings at the state and federal levels are also looking into causes of the high wholesale electricity prices in the western United States during 2000 and 2001. These investigations are to determine if suppliers should be required to refund some of the revenue earned during this period.

BC Hydro has recorded provisions for uncollectible amounts and legal costs associated with the ongoing legal and regulatory impacts of the California energy crisis. Management reviews these provisions regularly to ensure that they are sufficient to provide for any additional exposures.

Deferral Accounts

As disclosed in the Management Discussion and Analysis in the 2004 Annual Report, the Province issued a Special Directive that directs the British Columbia Utilities Commission to authorize BC Hydro to establish the Heritage Deferral Account and the Trade Income Deferral Account effective April 1, 2004. These accounts are intended to result in assigning domestic ratepayers the benefit of BC Hydro's low-cost generation assets and related activities, as well as an appropriate share of risks associated with the ownership and operation of these assets (the "Heritage Resources"). As part of the Revenue Requirement Application related to fiscal 2005 and 2006, BC Hydro has applied for the establishment of a Non-Heritage Asset Deferral Account to manage the impact of certain other non-controllable cost variances. The impact of this account would be to defer specific types of cost variances through transfers to/from the accounts by adjustment of net income.

While the deferral accounts are still under review by the Commission, BC Hydro has recorded the following amounts in the financial statements for the three and six months ended September 30, 2004.

	Income Statement		Balance Sheet
	Three months ended	*Six months ended*	*As at*
in millions	*September 30, 2004*		*September 30, 2004*
	Increase (Decrease) net income		Asset (Liability)
Heritage Deferral Account	$ 83	$ 137	$ 137
Non-Heritage Asset Deferral Account	3	31	31
Trade Income Deferral Account	(5)	(43)	(43)
Total Deferral Accounts	$ 81	$ 125	$ 125

Columbia Basin Power Projects

On September 30, 2004, the BC Hydro Board of Directors approved in principle a proposal to acquire the interest in power projects owned jointly by the Columbia Basin Trust ("CBT") and Columbia Power Corporation ("CPC"). The potential $800 million acquisition, including assumed debt of $280 million, of the hydroelectric facilities includes two operating facilities, one under construction and one project in development. BC Hydro is undertaking a due diligence review that is expected to take approximately three months. The results of this review will be considered by the BC Hydro Board of Directors prior to final approval.

Business Risks/Uncertainties

BC Hydro is subject to various risks and uncertainties that cause significant volatility in its earnings. Factors such as the level of water inflows into its reservoirs, market prices for electricity and natural gas, interest rates, foreign exchange rates, weather and regulatory and government policies influence both the operation of the BC Hydro system and its earnings. A reduction in water inflows into reservoirs results in a greater reliance on energy purchases or use of the Burrard Generating Station, both of which can increase the costs of energy. While these risks cannot be eliminated, as they are largely non-controllable, some may be mitigated to a certain degree as disclosed in BC Hydro's 2004 Annual Report. In addition, the impact of the revenue requirement application decision by the Commission on BC Hydro's earnings and operations will not be known until the fall of 2004.

Management's assessment of business risk/uncertainties is on going and the risks/uncertainties to BC Hydro have not changed materially from the Management Discussion and Analysis presented in the 2004 Annual Report.

Future Outlook

BC Hydro's income for this fiscal year is forecast to be $240 million before any transfers to or from the deferral accounts. This is a reduction of $35 million from the forecast disclosed in BC Hydro's first quarter report for fiscal 2005. The $35 million reduction in forecast income is largely due to an expected increase in energy purchases as a result of continued below-average water inflows and reservoir levels. BC Hydro's income can fluctuate significantly, due largely to non-controllable factors such as the market price of energy, weather, interest rates and water inflows. The range of income before deferral account transfers under plausible scenarios is estimated to be between $190 million and $315 million.

BC Hydro's forecast net income after deferral account transfers for fiscal 2005 is approximately $425 million. The forecast of $425 million is after the impacts of lower water inflows, higher energy purchase volumes and prices and an increase in trade income have been taken into account through the proposed deferral accounts.

FINANCIALS

CONSOLIDATED STATEMENT OF OPERATIONS

(Unaudited)	For the three months Ended September 30		For the six months Ended September 30	
(in millions)	**2004**	2003 (Restated - Note 3)	**2004**	2003 (Restated - Note 3)
Revenues				
Residential	**$ 198**	$ 182	**$ 415**	$ 390
Light industrial and commercial	**239**	222	**475**	439
Large industrial	**148**	127	**292**	256
Other energy sales	**19**	20	**38**	36
Miscellaneous	**12**	14	**28**	27
	616	565	**1,248**	1,148
Electricity trade	**282**	283	**468**	482
	898	848	**1,716**	1,630
Expenses				
Energy costs	**510**	406	**916**	797
Maintenance	**62**	86	**118**	144
Operations and administration	**71**	63	**161**	163
Taxes	**35**	36	**71**	71
Amortization	**108**	99	**216**	197
	786	690	**1,482**	1,372
Income Before Finance Charges and Deferral Account Transfers	**112**	158	**234**	258
Finance charges	**101**	119	**215**	219
Income Before Deferral Account Transfers	**11**	39	**19**	39
Transfer (to) from (Note 5)				
Heritage Deferral Account	**83**	-	**137**	-
Non-Heritage Deferral Account	**3**	-	**31**	-
Trade Income Deferral Account	**(5)**	-	**(43)**	-
Net Income	**$ 92**	**$** 39	**$ 144**	**$** 39

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(Unaudited)	for the Six Months Ended September 30	
(in millions)	**2004**	2003
Retained earnings, beginning of period as previously reported	**$ 1,634**	$ 1,609
Note 3: Adoption of new accounting standard for asset retirement obligations	**241**	233
Retained earnings, beginning of period as restated	**$ 1,875**	$ 1,842
Net income	**144**	39
Accrued Payment to the Province	**(117)**	(17)
Retained earnings, end of period	**$ 1,902**	$ 1,864

See accompanying notes to the interim consolidated financial statements.

FINANCIALS

CONSOLIDATED BALANCE SHEET

(in millions)	as at September 30 2004 (Unaudited)	as at March 31 2004 (Restated – Note 3)
ASSETS		
Capital Assets		
Capital assets in service	**$ 15,477**	$ 15,307
Less accumulated amortization	**6,128**	5,922
	9,349	9,385
Unfinished construction	**571**	515
	9,920	9,900
Current Assets		
Cash and cash equivalents	**44**	47
Accounts receivable and accrued revenue	**278**	323
Materials and supplies	**90**	86
Prepaid expenses	**168**	108
Unrealized gains on mark-to-market transactions	**108**	104
	688	668
Other Assets and Deferred Charges		
Loan receivable	**2**	2
Sinking funds	**934**	981
Demand-side management programs	**188**	161
Deferred debt costs	**79**	150
Deferral accounts (Note 5)	**125**	–
	1,328	1,294
	$ 11,936	$ 11,862
LIABILITIES AND EQUITY		
Long-Term Debt		
Long-term debt net of sinking funds	**$ 6,030**	$ 5,927
Sinking funds presented as assets	**934**	981
	6,964	6,908
Foreign Currency Contracts	**78**	63
Current Liabilities		
Current portion of long-term debt	**952**	973
Accounts payable and accrued liabilities	**591**	673
Accrued interest	**118**	115
Accrued Payment to the Province	**117**	73
Unrealized losses on mark-to-market transactions	**98**	78
	1,876	1,912
Deferred Credits and Other Liabilities		
Asset retirement obligations (Note 3)	**17**	16
Deferred revenue	**273**	276
Contributions arising from the Columbia River Treaty	**189**	193
Contributions in aid of construction	**637**	619
	1,116	1,104
Retained Earnings	**1,902**	1,875
	$ 11,936	$ 11,862

See accompanying notes to the interim consolidated financial statements.

On behalf of the Board:

L.I. (Larry) Bell
Chair

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

FINANCIALS

CONSOLIDATED STATEMENT OF CASH FLOWS

(Unaudited)	*For the three months Ended September 30*		*For the six months Ended September 30*	
(in millions)	**2004**	2003 *(Restated - Note 3)*	**2004**	2003 *(Restated - Note 3)*
Operating Activities				
Net income	**$ 92**	$ 39	**$ 144**	$ 39
Adjustments for:				
- Amortization	**108**	99	**216**	197
- Deferral accounts	**(81)**	-	**(125)**	-
- Other non-cash items	**(20)**	10	**26**	(8)
	99	148	**261**	228
Working capital changes	**(164)**	(194)	**(111)**	(60)
Cash provided by (used for) operating activities	**(65)**	(46)	**150**	168
Investing Activities				
Loan receivable	**1**	-	**-**	-
Capital asset expenditures	**(132)**	(162)	**(245)**	(319)
Contributions in aid of construction	**19**	18	**35**	22
Demand-side management programs	**(13)**	(11)	**(40)**	(19)
Cash used for investing activities	**(125)**	(155)	**(250)**	(316)
Financing Activities				
Bonds:				
- Issued	**10**	200	**540**	640
- Retired	**(71)**	-	**(506)**	(300)
Revolving borrowings	**4**	(1)	**82**	150
Sinking funds	**22**	(15)	**52**	3
Deferred debt costs	**-**	-	**(5)**	7
Settlement of interest rate swaps	**12**	-	**7**	-
Cash provided by financing activities	**(23)**	184	**170**	500
Payment to the Province	**-**	-	**(73)**	(338)
Increase (Decrease) in cash and cash equivalents	**(213)**	(17)	**(3)**	14
Cash and cash equivalents at beginning of period	**257**	35	**47**	4
Cash and cash equivalents at end of period	**$ 44**	$ (18)	**$ 44**	$ 18
Supplemental disclosure of cash flow information				
- Interest paid	**$ 142**	$ 157	**$ 260**	$ 261

See accompanying notes to the interim consolidated financial statements.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) SEPTEMBER 30, 2004

Business of BC Hydro

British Columbia Hydro and Power Authority ("BC Hydro") is a provincial Crown corporation. BC Hydro's mission is to provide integrated energy solutions to customers in an environmentally and socially responsible manner.

BC Hydro serves more than 1.6 million customers in an area containing over 94 per cent of British Columbia's population. Between 43,000 and 54,000 gigawatt hours of electricity are generated annually, depending upon prevailing water levels. Electricity is delivered to customers mainly through an interconnected system of nearly 73,000 kilometres of transmission and distribution lines.

BC Hydro's Board of Directors is appointed by the Lieutenant Governor in Council and is responsible for the overall direction of the company.

Note 1: Accounting Policies

These interim consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) for preparation of interim financial statements and do not conform in all respects to the disclosure requirements for annual financial statements. These interim consolidated financial statements follow the same accounting policies as the most recent annual consolidated financial statements, except for the accounting of asset retirement obligations and hedging relationships as discussed below. These interim consolidated financial statements take into account certain accounting practices by regulatory bodies that differ from the accounting practices applied in unregulated enterprises. The differences specifically relate to certain deferred charges.

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 2004 Annual Report.

On April 1, 2004, BC Hydro adopted two new accounting standards in accordance with the Canadian Institute of Chartered Accountants ("CICA") Handbook. The first, Section 3110 "Asset Retirement Obligations", replaces the provision for Future Removal and Site Restoration that had been recorded in accordance with the previous requirements of CICA Handbook Section 3061. Asset Retirement Obligations are disclosed in Note 3. The second, Accounting Guideline 13 "Hedging Relationships," was adopted with respect to hedging transactions and is described in Note 4.

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

Note 2: Seasonality of Operating Results

Due to the seasonal nature of the BC Hydro's operations, interim operations statements are 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 3: Asset Retirement Obligations

For fiscal periods to March 31, 2004, BC Hydro recorded a provision for the estimated future costs associated with the retirement and decommissioning of its distribution, transmission and generation facilities in accordance with the previous requirements of CICA Handbook Section 3061. Effective April 1, 2004, BC Hydro adopted the new section (Section 3110 "Asset Retirement Obligations"), which addresses accounting and reporting for obligations associated with the retirement of long-lived assets.

This new section amends Section 3061 and applies only to legal obligations associated with the retirement of long-lived assets. BC Hydro is required to record the net present value of a liability at the time it is incurred if an estimate can be determined. When a liability is initially recorded, BC Hydro will capitalize the costs by increasing the carrying value of the long-lived asset. The liability is adjusted for the passage of time through accretion (interest) expense and the asset is amortized over the useful life of the related asset. The change in accounting policy has been applied retroactively with restatement of prior periods.

The change in accounting policy requires BC Hydro to remove the existing provision for future removal and site restoration costs. Asset retirement obligations and associated capital assets were set up for assets that it is legally obligated to retire, with the difference between the existing provision and the net liability created by the new accounting policy being an adjustment to retained earnings. The majority of BC Hydro's facilities have an indeterminate life, and thus a future retirement obligation is not determinable.

The net impacts of this change in accounting policy are summarized below:

	For the Six Months Ended September 30	
	2004	2003
in millions	Increase (Decrease)	
Opening balances		
Retained Earnings	**$ 241**	$ 233
Capital Assets, net	**8**	7
Deferred Credit and Other Liabilities	**(233)**	(167)
Net income	**$ -**	$ 6

Note 4: Hedging Relationships

In December 2001, the CICA issued Accounting Guideline 13, "Hedging Relationships". The effective date of this Guideline was deferred to fiscal years beginning on or after July 1, 2003. The Guideline addresses the types of items that qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting and the requirement to evaluate hedges for effectiveness. The Guideline does not specify how hedge accounting should be applied but Emerging Issues Committee ("EIC") Abstract 128, "Accounting for Trading, Speculative or Non-hedging Derivative Financial Instruments", requires derivatives that are not designated as hedges to be recorded at fair value on the Company's consolidated balance sheet, with changes in fair value recorded in earnings. This Guideline was adopted prospectively effective April 1, 2004 for treasury instruments. The impact of this change in hedge accounting is an $11 million increase in net income for the three months ended September 30 and a $7 million increase in net income for the six months ended September 30. The hedge accounting provisions were adopted for energy trading activities in fiscal 2004.

Note 5: Deferral Accounts

During fiscal 2004, the Province issued a Special Directive that directs the British Columbia Utilities Commission (the "Commission") to authorize BC Hydro to establish the Heritage Deferral Account and the Trade Income Deferral Account effective April 1, 2004. These accounts are intended to result in assigning domestic ratepayers the benefit of BC Hydro's low-cost generation assets and related activities, as well as an appropriate share of risks associated with the ownership and operation of these assets (the "Heritage Resources").

Heritage Deferral Account

The Heritage Deferral Account is intended to mitigate the impact of certain variances between the forecast and actual costs of service associated with the Heritage Resources. The impact of this account is to defer the impact of these cost variances through transfers to or from the account by adjustment of net income.

Trade Income Deferral Account

The Trade Income Deferral Account is intended to mitigate the uncertainty associated with forecasting the net income of BC Hydro's electricity trade activities. The impact of this account is to defer the difference between forecast and actual Trade Income. For the purposes of this calculation, Trade Income is defined as the Net Income of Powerex based on Canadian GAAP. The Special Directive provides that in each fiscal year the portion of the variance between forecast and actual Trade Income in excess of $200 million per year or a loss in Trade Income will not be included in the Trade Income Deferral Account.

Non-Heritage Asset Deferral Account

As part of the Revenue Requirement Application related to fiscal 2005 and 2006, BC Hydro has applied for the establishment of a Non-Heritage Asset Deferral Account to manage the impact of certain other non-controllable cost variances. The impact of this account would be to defer specific types of cost variance through transfers to or from the account by adjustment of net income.

As at September 30, 2004, the deferral accounts on the balance sheet are:

(in millions)	*Asset (Liability)*
Heritage Deferral Account	$ 137
Non-Heritage Asset Deferral Account	31
Trade Income Deferral Account	(43)
Total Deferral Account	$ 125

Note 6: Commitments and Contingencies

Alcan Inc:

During fiscal 2002, Enron Corp. ("Enron") and certain of its subsidiaries, including Enron Power Marketing, Inc. ("EPMI"), filed for bankruptcy protection. As a result, Powerex's Power Purchase and Sale Agreement with EPMI terminated, giving rise to a termination payment becoming due from EPMI. Under a 1997 agreement among Alcan Inc., formerly Alcan Aluminum Limited, ("Alcan"), EPMI, Powerex and BC Hydro, Alcan agreed to remain liable to Powerex for payment obligations of EPMI up to US$100 million.

Alcan did not pay the termination payment when demand was made by Powerex, and the matter was referred to arbitration in the United States. Early in 2003 an arbitration award was issued, which required Alcan to pay Powerex US$100 million within 30 days, with interest accruing thereafter. This amount was not paid and Powerex commenced enforcement proceedings in the British Columbia Supreme Court (the "B.C. Enforcement Proceedings").

The B.C. Enforcement Proceedings were adjourned pending the outcome of an application by Alcan in the U.S. District Court to have the arbitration award set aside. Alcan's application was subsequently denied and Alcan appealed that decision to the Ninth Circuit Court of Appeals. Despite the appeal, Powerex resumed the B.C. Enforcement Proceedings and its application was heard in April 2004. On June 30, 2004, a judgment was issued in the B.C. Enforcement Proceedings adjourning the proceedings on the condition that Alcan pay US$100 million plus accrued interest into a trust account. These funds would be available for use by Powerex upon its posting of security satisfactory to Alcan. Alcan applied for leave to appeal this decision.

A hearing on the above request for appeal and/or stay of the decision pending appeal was held September 7, 2004, in the BC Court of Appeals, and on October 4, 2004, the judge issued his decision granting Alcan's request to appeal the Award, but also refusing a stay of the requirement that Alcan pay to Powerex the Award (plus interest) with the guarantee that Powerex would repay that amount to Alcan if the award were set aside by an appeal.

On October 7, 2004, Alcan withdrew from all legal challenges to the arbitration award and signed, along with Powerex, an agreement concerning the final resolution of this matter. Alcan and Powerex are discussing alternatives concerning the nature and timing of payment. The payment has not been recognized in the company's financial statements.

California Power Markets

On September 9, 2004, the U.S. Ninth Circuit Court of Appeals issued a ruling in the case Lockyer v. the U.S. Federal Energy Regulatory Commission (FERC). This case involved FERC's dismissal of a March 20, 2002, complaint filed by California Attorney General Lockyer against Powerex and other named respondents, alleging that FERC's market-based rate program (administration of Power Marketing Authorization or PMA) was illegal or, alternatively, that FERC's failure to enforce its transaction-specific quarterly reporting requirements and sellers' failures to comply with such regulations deprived sellers of the protection of the filed rate doctrine.

In its ruling, the court stated that the FERC "abused its administrative discretion by declining to order refunds for violations" of the agency's reporting rules under the Federal Power Act, and sent the case back to FERC for further consideration.

The ruling may impact a number of issues previously decided by FERC, including Powerex's US$1.3 million FERC Settlement Agreement. Powerex and its legal counsel are closely reviewing the decision and following developments in the case to better determine the implications of the case and Powerex's response.

No adjustment to provisions has been made as a result of this recent ruling.

Columbia Basin Power Projects

On September 30, 2004, the BC Hydro Board of Directors approved in principle a proposal to acquire the interest in power projects owned by the Columbia Basin Trust and Columbia Power Corporation. The potential $800 million acquisition of the hydroelectric facilities includes assumed debt of $280 million, two operating facilities, one under construction and one project in development. BC Hydro is undertaking a due diligence review that is expected to take approximately three months. The results of this review will be considered by the BC Hydro Board of Directors prior to final approval.

Other:

There are no other material changes to the commitments and contingencies disclosed in the notes to BC Hydro's 2004 Annual Consolidated Financial Statements.

Note 7: Employee Future Benefits

BC Hydro's cost for employee future benefits for the three months ended September 30 was $19 million (2003 – $19 million). The cost for employee future benefits for the six months ended September 30 was $37 million (2003 – $39 million). compared to $39 million for the same period in the prior year.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) SEPTEMBER 30, 2004

Note 8: Segmented Information

Three months ended September 30, 2004

(in millions)	Distribution $	Transmission $	Generation $	Powerex $	Other $	Consolidation Adjustments/ Eliminations $	Total $
External revenues	607	3	-	282	10	(4)	898
Inter-segment revenues	43	155	376	171	100	(845)	-
Net income (loss)	10	25	48	43	9	(43)	92

Three months ended September 30, 2003 (restated)[3]

(in millions)	Distribution $	Transmission $	Generation $	Powerex $	Other $	Consolidation Adjustments/ Eliminations $	Total $
External revenues	550	3	4	271	11	9	848
Inter-segment revenues	0	165	345	94	116	(720)	-
Net income (loss)	(111)	36	115	56	(6)	(51)	39

Six months ended September 30, 2004

(in millions)	Distribution $	Transmission $	Generation $	Powerex $	Other $	Consolidation Adjustments/ Eliminations $	Total $
External revenues	1,222	7	(4)	477	24	(10)	1,716
Inter-segment revenues	87	310	770	318	195	(1,680)	-
Net income (loss)	(11)	54	98	88	2	(87)	144
Total assets	3,670	3,070	4,563	802[1]	563[2]	(730)	11,936

Six months ended September 30, 2003 (restated)[3]

(in millions)	Distribution $	Transmission $	Generation $	Powerex $	Other $	Consolidation Adjustments/ Eliminations $	Total $
External revenues	1,120	6	8	482	21	(7)	1,630
Inter-segment revenues	-	331	688	243	201	(1,463)	-
Net income (loss)	(201)	82	172	94	8	(116)	39
Total assets	3,236	3,143	4,927	448[1]	499[2]	(386)	11,867

1 Includes inter-segment receivables of $114 million (2003 – $125 million).

2 Consists mainly of capital assets such as office buildings, vehicles and computer equipment.

3 Restated for retroactive application of the asset retirement obligations accounting standard (Note 3).

4. Lines of Business Performance

GENERATION

Cost of Heritage Electricity ▼ ($/MWh)
Annual Target $25.60/MWh

	Actual	Target
Excluding Return on Equity		
Q2 04/05	$28.76	$21.41
Including Return on Equity*		
Q2 04/05	$33.08	$25.20

*as defined in the Heritage Special Directive No. HC-2

For the second quarter, the Cost of Heritage Electricity was higher than target. This is due to the low inflow forecast, resulting in the need for higher-than-plan electricity purchases (2,130 GWh purchased compared with 183 GWh plan) and electricity purchase prices higher than plan (average actual purchase price of $56.67 compared with plan of $53.55 per GWh).

Commercial Performance ▲
Annual Target 99.50%

	Actual	Target
Q2 04/05	99.94%	99.50%

Equipment reliability and availability are tracking better than target for the second quarter.

Average Number of Forced Outages ▲
Annual Target 3.2

	Actual	Target
Q2 04/05	0.73	0.8

Equipment is operating more reliably than planned.

Resource Smart Energy Gains Put into Service (GWh) ●
Annual Target 104 GWh

	Actual	Target
Q2 04/05	0	0

The Resource Smart program gains are forecast to be on target at the end of the fiscal year.

DISTRIBUTION

COMA / Customer ●

(Capital and OMA cost per customer – dollars)

Annual Target – $267.60

	Actual	Target
Q2 04/05	$67.90	$68.40
Q2 03/04	$65.60	N/A

The COMA/Customer measure for the second quarter is on target.

Customer-Based Generation GWh ▼

Annual Target – 275 GWh

	Actual	Target
YTD Q2 04/05	259	275
YTD Q2 03/04	50	N/A

Customer-Based Generation (GWh) - Two projects are online. Target shown is annual.

The Customer-Based Generation measure was below target for the second quarter.

Green Gigawatt Hours ●

Annual Target 756 GWh

	Actual	Target
YTD Q2 04/05	665	665
YTD Q2 03/04	120	N/A

Green GWh - Twelve projects forecast are online.Target shown is annual.

ENGINEERING SERVICES

Utilization Rate ●

Annual target – 83%

	Actual	Target
Q2 04/05	83%	83%

The Utilization Rate measure for the second quarter was on target.

Hourly Charge-out Rate ●

Annual target – $97

	Actual	Target
Q2 04/05	$96.0	$97.0

The Hourly Charge-out Rate measure for the second quarter was on target.

% of Approved EIT and GTT Positions Filled ●

Annual target – 100%

	Actual	Target
Q2 04/05	100%	100%

Percentage of EIT and GTT Positions Filled is on target for the second quarter.

FIELD SERVICES

All Injury Frequency ▲

	Actual	Target	Prior Year
Q2 04/05	4.0	4.7	5.1

Despite a fatal accident in September, All Injury Frequency was significantly better than target for the second quarter, primarily as a result of continued employee and management emphasis on safety.

Utilization Rate ●

	Actual	Target	Prior Year
Q2 04/05	74.4%	75.5%	74.7%

Hourly Charge-out Rate ●

	Actual	Target	Prior Year
Q2 04/05	$91	$95	$96

The Hourly Charge-out Rate measure for the second quarter is marginally below target as Construction Business Unit, which traditionally charges out at lower rates, contributed significantly more to the increased chargeable hours relative to plan.

% Of Total Planned Work Completed ▼

	Actual	Target	Prior Year
Q2 04/05	92%	100%	103%

This measure is a proxy measure of customer satisfaction. High levels of completed work have historically correlated to high levels of customer satisfaction. Targets have been set based on customer expectations. Performance is below target for some transmission, vegetation and distribution maintenance work programs. Plans have been prepared to achieve 90 to 100 per cent completion by December 31, 2004.

Total Trainees - Strategic Workforce Planning ●

	Actual	Target	Prior Year
Q2 04/05	120	132	87

Field Services continues to invest in building a highly skilled workforce, with trainees accounting for nearly 10 per cent of the regular employee base. Strategic Workforce Planning (SWfP) is defined as the number of apprentices/trainees in Field Services who are being trained to fill positions as a result of retirement, attrition or other core workforce requirements. The targets have been set based on an internal needs assessment against expected organizational capacity.

With the hiring of 15 Power Line Technician apprentices in September, the total number of SWfP hires to date for fiscal 2005 is 24 (target is 32). It is anticipated that there will be approximately 132 apprentices/trainees on the system by fiscal year-end. Field Services has received significant external and internal interest from a job bulletin that closed on October 1, 2004, for eight SWfP Managers. Field Services is the process of reviewing applications and interviewing promising candidates.

POWEREX

Transactions per Employee ▲

	Actual	Target
Q2 04/05	230	165

Powerex's second quarter TPE is 230, compared with plan of 165. This was due to increased transaction levels, as summer is typically Powerex's busy season. The increase in transactions was largely attributed to Real Time and Prescheduled transactions. Based on current results, Powerex expects to meet its annual TPE target of 660.

5. British Columbia Transmission Corporation Performance

Transmission Utilization Ratio ●

	Actual	Target
Q2 04/05	65%	65%

SAIDI (System Average Interruption Duration Index) ▲

	Actual	Target
Q2 04/05	1.9	2.2

NERC/WECC Compliance ●

	Actual	Target
Q2 04/05	Full Compliance	Full Compliance

Number of Preventable Lost-Time Accidents ●

	Actual	Target
Q2 04/05	0	0

Number of Preventable and Reportable Environmental Incidents ●

	Actual	Target
Q2 04/05	2	2 per annum

Preventable environmental incidents are primarily the result of human error, either by BCTC staff or BCTC contractors.

Two incidents occurred during the second quarter.

(1) During a tower replacement project, a contractor drove an excavator through a river bank and crossed two streams without a permit.

(2) A vegetation contractor cleared all willow and hawthorn to the ground within a vegetation management area without the required approvals under the BCTC, Department of Fisheries and Oceans (DFO) and B.C. Ministry of Water, Land and Air Protection Approved Work Practices for Riparian Vegetation.

Completion of Planned Safety and Environment Management Programs ●

	Actual	Target*
Q2 04/05	89% (estimated)	85%

*Target: 85% of planned activities completed for the year.

BCTC is implementing new safety management and environmental management systems. The second-quarter results are ahead of target.

Glossary for Performance Measures

All Injury Frequency (AIF) is defined as the total number of employee injuries (Medical Aids and Disabling Injuries), relative to the number of worked hours in the same period. For this measurement, Medical Aid injuries are defined as those where a professional medical practitioner has rendered services beyond the level defined as "first aid" in relation to the injury incident, and the employee was not absent from work beyond time lost on the day of the injury. Disabling injuries are defined as those that involve the employee being absent from work beyond the day of the injury.

Approved Strategic Workforce Positions Filled is defined as the number of positions filled under BC Hydro's Strategic Workforce Planning (SWfP) initiative. SWfP is the management process for anticipating, scoping and planning the alignment of needed critical workforce capabilities to meet BC Hydro's strategic business goals. The targets were set based on internally performed needs assessments.

A preventable lost-time accident is one in which BCTC and its employees failed to foresee a risk and act to avoid an accident.

Average number of Forced Outages per unit (count) is defined as the total number of forced outages divided by the total number of units.

COMA/Customer is defined as gross recurring capital expenditures (net of Telus recoveries) and operations, maintenance and administrative expenses divided by the total number of customers. BC Hydro's Distribution Line of Business includes a number of functions that are not included in industry benchmarks. The PA Consulting and Canadian Electricity Association benchmarks are based only on the expenditures associated with the distribution of electricity.

Commercial Performance is defined as revenue from energy produced relative to the revenue from energy that could have been produced had all generation needed to meet domestic load and trade opportunities been available. The annual target is based on historical performance (including analysis of planned outages) and assessment of reasonable improvement given investment in assets.

Conservation Gigawatt Hours is defined as the rate at which annual gigawatt hours (GWh) are being saved as a result of economic demand-side management. The targets are based on net savings from current Power Smart programs and programs expected to come on-stream. The targets include both residential and business demand-side management.

Cost of Heritage Electricity (or Cost per MWh including Electricity Purchases) is defined as all Generation costs, including the cost of electricity purchases, divided by the actual volume of energy supplied to Distribution. It provides an indication of Generation's efficiency of producing and purchasing electricity.

Customer-Based Generation GWh is defined as gigawatt hours from customer-based sources (industrial or large commercial customers) that meet purchase price limits. Targets have been set to align with the Government objective of 50 per cent of new electricity supply from clean energy sources.

Environmental Regulatory Compliance (ERC) is defined as the number of externally reportable, preventable environmental incidents. For this type of measure there is an inherent risk of unreported incidents. BC Hydro is reviewing its controls to attempt to ensure that all applicable incidents are reported.

Green Gigawatt Hours is defined as gigawatt hours contracted from green sources that meet purchase price limits. A green source of energy must be: renewable, licensable, socially responsible and have low environmental impact. Targets have been set to align with the Government objective of 50 per cent of new electricity supply from clean energy sources.

Hourly Charge-out Rate (Engineering) is defined as the weighted average hourly rate charged by Engineering Services. It is calculated as net revenue less the contract hire margin divided by total billable hours. Targets have been set based on improvements to historical performance.

Hourly Charge-out Rate (Field Services/CBU) is defined as the average hourly billing rate designed to recover all costs providing the service. Targets have been set based on expected efficiency gains and external benchmarks. This is a blended Field Services/Construction Business Unit rate.

Labour Utilization (Field Services/CBU) is defined as the number of chargeable hours divided by the total of all labour hours available. Targets have been set based on improvements to historical performance. Standby is not currently included in this measure but is being addressed as part of the Field Services pricing and service level agreement process. This is a blended Field Services/Construction Business Unit (CBU) rate.

NERC/WECC Compliance is defined as compliance with reliability standards established by the WECC and the security standards established by NERC.

Percentage of Approved Engineer-in-Training (EIT) and Graduate Technologist-in-Training (GTT) Positions Filled is defined as the percentage of EIT and GTT targeted positions that are filled. The targets have been set based on an internal needs assessment against expected organizational capacity.

Percentage of Total Planned Work Completed is defined as the total planned customer work assigned to Field Services divided by total planned customer work completed.

Reliability is defined in terms of Average System Availability Index (ASAI) and Customer Average Interruption Duration Index (CAIDI). ASAI is the percentage of time power is available. CAIDI is the average number of hours per interruption.

Resource Smart Energy Gains Put into Service is defined as the projected, long-term average incremental energy gains from existing Generation facilities, which are put into service.

SAIDI is a statistical measure of transmission related outages caused by unforeseen events such as equipment failure or weather-related outages based on a rolling 12-month average.

Transactions per Employee (TPE) is defined as the number of transactions conducted by Powerex, divided by the number of Powerex employees.

Transmission Utilization Ratio is defined as the ratio of total transmission capacity sold to total transfer capability. This measures how much of the transmission grid's capacity is actually sold to customers, generating additional revenue. This measure is based on a rolling 12-month average.

Utilization Rate (Engineering) is defined as billable hours divided by total hours worked. Targets have been set based on moving towards first-quartile (top 25 per cent) when compared with other engineering firms.