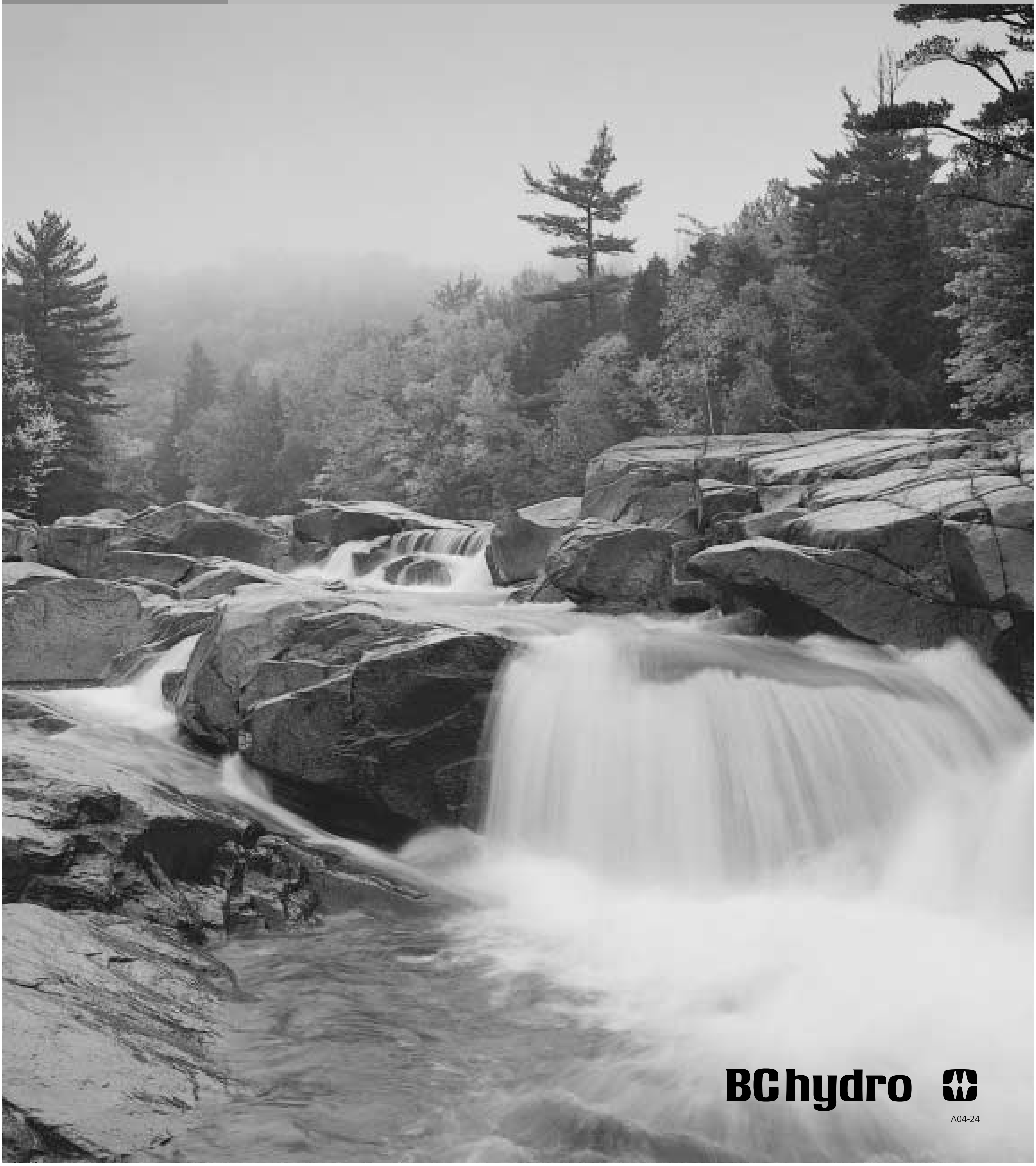
Third Quarter Report

For the nine months ended December 31, 2003



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1. OVERVIEW

KEY HIGHLIGHTS

Financial

- Consolidated net income of $150 million for the nine months ended December 31, 2003, was $156 million lower than for the same period in the previous year. The primary reason for the decline in net income is a decrease in margins (revenue less energy costs) of $119 million. This was caused by increasing cost of supply, due to an increase in market prices for energy, and higher purchase volumes. Higher purchases were needed because system storage energy in BC Hydro's major reservoirs at the end of the third quarter was about 800 gigawatt hours below the historical average for this time of year.
- Also contributing to the lower net income was an increase of $51 million in maintenance expenses, due primarily to increases in maintenance performed as a result of forest fire damage, province-wide storms in October and routine maintenance being advanced earlier this year. Additionally, operations and administration expenses increased $13 million, largely due to increases in pension costs, one-time expenditures related to the new transmission company, British Columbia Transmission Corporation (BCTC), and implementation costs related to IT projects. A decrease in finance charges of $30 million due to the decline in interest rates partly offset the increased costs.
- Net income from domestic sources for the nine months ended December 31, 2003, was $37 million, while electricity trade sources provided net income of $113 million. This compares with net income from domestic sources of $221 million and net income from electricity trade sources of $85 million for the same period in the prior year.
- BC Hydro's forecast net income before Rate Stabilization Account (RSA) transfers for fiscal 2004 is approximately $190 million. Based on this forecast, the balance of $21 million remaining in the RSA at the end of fiscal 2003 will be depleted. The forecast of $190 million is an increase of $260 million from the forecast in BC Hydro's 2003 Service Plan and an increase of $45 million from the forecast disclosed in BC Hydro's September 2003 Quarterly Report. The increase from the Service Plan forecast to the second-quarter forecast was largely due to the impact of improved water inflows during the spring and to a decrease in the prices of electricity and natural gas purchases. Lower-than-expected interest rates also contributed to the increase in the forecast. The improvement in the forecast from the second quarter is primarily due to an increase in domestic revenues, largely in the residential sector due to weather impacts.
- BC Hydro filed its first revenue requirements application in almost 10 years on December 15, 2003, with the British Columbia Utilities Commission (BCUC) requesting a general rate increase of 7.23 per cent effective April 1, 2004, and a further increase of two per cent effective April 1, 2005. The process of reviewing and determining the appropriate rates for BC Hydro is anticipated to be lengthy and will not be completed by April 1, 2004. Thus, BC Hydro sought interim rate relief effective April 1, 2004 to permit it an opportunity to earn its allowed rate of return on equity in fiscal 2005. On January 23, 2004, the BCUC approved the first-year increase of 7.23 per cent on an interim basis, effective April 1, 2004. Public hearings will begin on May 17, 2004 to determine the final rate increase. The BCUC will make a final decision in the fall and, if it is a lower amount or a rate increase is denied, the difference will be fully refundable with interest to BC Hydro customers.

- BC Hydro is subject to various risks and uncertainties that can cause significant volatility in the 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 increased use of the Burrard Generating Station, both of which can result in higher costs of energy. As a result of these risks and uncertainties, BC Hydro's net income for fiscal 2004 could range from $130 million to $220 million under various plausible scenarios.

Performance Plan

- BC Hydro had a successful third quarter, which was reflected in the performance measures. Five of the six corporate measures reported on either met (2) or exceeded (3) their quarterly targets. BC Hydro was slightly below its quarterly reliability target, with the average number of hours per interruption worse than target. The main reasons for this were beyond BC Hydro's control, specifically four major weather events and the McLure forest fire in the Interior of B.C.
- Net Income was better than the plan loss of $41 million, primarily as a result of lower finance charges, an increase in electricity trade margins, and higher domestic revenues due largely to weather impacts. Net income is expected to remain ahead of plan for the year due to these favourable factors.
- BC Hydro was above its quarterly safety goal, as measured by All Injury Frequency. BC Hydro is benefiting from the focus that has been placed on safety and performance improvement through awareness, planning, training and safe work practices.

Domestic Supply and Demand

- Total sales compared with last year over the first eight months of the fiscal year were up 430 GW.h or 1.4 per cent higher. Of this total, Transmission sales were up 194 GW.h or 1.9 per cent higher; General Sales were up 176 GW.h or 1.6 per cent higher; Residential sales were up 72 GW.h or 0.8 per cent higher; and total Other sales were down 11 GW.h or about 1.0 per cent lower.
- BC Hydro is a winter peaking utility driven by residential electric space heating. A one-hour peak demand of 8,883 MW at a daily average temperature of –0.9°C was reached on December 30, 2003. Although information for this quarter's report is up to December 31, 2003, it is worth noting that BC Hydro reached an all-time record peak of 9,619 MW on January 5, 2004 at a daily average temperature of –7.1°C measured at the Vancouver International Airport. As temperatures moderate in the spring and summer months, the system peak demand is reduced.
- System storage energy on December 31, 2003, was about 800 GW.h below the historical average for this time of year. The combined storage in BC Hydro's major reservoirs at December 31, 2003, was one per cent below average. This compares with the combined storage of BC Hydro's major reservoirs at December 31, 2002, of two per cent below average. With system energy below normal, net energy purchases will be required through to the end of the fiscal year.
- The snowpack accumulation through the fall and early winter has been below normal for the large interior basins in the Williston, Kinbasket and Kootenay regions and normal to slightly above normal for Vancouver Island and the Lower Mainland. The weighted BC Hydro system total inflow forecast for the February through September 2004 period is 94 per cent

of normal (with a standard error of plus or minus 12 per cent). The forecasts for major basins are 92 per cent at Williston, 94 per cent at Kinbasket, 89 per cent at Revelstoke and 99 per cent at Arrow.

Lines of Business

- For the third quarter of this fiscal year, total cumulative run-rate energy achieved was 586 GW.h/yr., placing Power Smart slightly ahead of the first-quarter target of 575 GW.h/yr. and on track to reach this year's cumulative target of 810 GW.h/yr.
- BC Hydro announced a 15-year agreement with Canadian Forest Products Ltd. (Canfor) on October 31 to update its Prince George Pulp and Paper mill to provide all of the electricity needs at that mill and its Intercontinental Pulp mill. BC Hydro will contribute $49 million to Canfor's $81 million project to install a 48 megawatt (MW) turbo generator project at the mill site, saving BC Hydro enough electricity to serve 39,000 homes. Canfor's project will generate 390 gigawatt hours (GW.h). BC Hydro is contributing about 1.5 cents/kW.h to the cost, which is significantly lower than BC Hydro's cost of 5.5 cents/kW.h for acquiring new generation.
- BC Hydro launched a campaign in September to educate customers across B.C. about the benefits of energy conservation and encourage Power Smart program participation, including energy-efficient compact fluorescent light bulbs (CFLs). As part of the promotion, BC Hydro mailed more than 700,000 Lower Mainland customers a direct mail voucher for two free CFLs, which they can then redeem at a Power Smart booth at a local retail location. Only a week after the launch, over 50,000 customers had participated, and, as of December 31, 2003, over 300,000 customers had redeemed their voucher at a retailer.
- Net new customer additions totalled 6,527 for the third quarter, an increase of 16.5 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 in the southern part of the province and the volume of initial requests for estimates received from the development community.
- BC Hydro issued its Call for Tenders (CFT) for capacity and associated energy supply on Vancouver Island on October 31, 2003. Twenty-three private sector developers registered to participate in the CFT process; of those, 14 chose the VIGP Election, indicating interest in acquiring the VIGP development assets and the proposed Duke Point site. On December 1, registered bidders submitted over 250 comments to BC Hydro regarding the CFT and the Preliminary Form Agreements. BC Hydro posted responses to all bidders' comments on December 15 and indicated that certain revisions would be made to the CFT and associated agreements. A revised CFT, Preliminary Form Energy Purchase Agreement and Preliminary Form VIGP Transfer agreement are to be filed with the BCUC in early January. On January 23, 2004, the BCUC provided a response on the Vancouver Island CFT process. BC Hydro is reviewing the BCUC response.
- Accenture Business Services of British Columbia (ABS) assumed responsibility for the performance of all Customer Care functions as of April 1, 2003. BC Hydro is receiving service at the levels received prior to the outsourcing agreement on the vast majority of metrics in the contract, and in many instances, service performance is exceeding the targets set.
- On November 21, 2003, the Lieutenant Governor in Council designated Key Agreements between BC Hydro and British Columbia Transmission Corporation (BCTC), pursuant to the Transmission Corporation Act. The agreements officially took effect on December 1, 2003 and formally define BCTC's role to independently operate, maintain and plan the transmission system on behalf of BC Hydro.

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 2003 Annual Report, the 2003 Audited Consolidated Financial Statements of BC Hydro and the consolidated financial statements of BC Hydro for the three and nine months ended December 31, 2003 and 2002. 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

- Net income of $150 million for the nine months ended December 31, 2003, was $156 million lower than for the same period in the previous year. The primary reason for the decline in net income is a decrease in margins (revenues less energy costs), of approximately $119 million, caused by increasing cost of supply due to an increase in market prices for energy and to higher purchase volumes. Also contributing to the lower net income was an increase of $51 million in maintenance expenses, due primarily to increases in maintenance performed as result of forest fire damage, province-wide storms in October and routine maintenance being performed earlier this year. A decrease in finance charges of $30 million due to the decline in interest rates partly offset the increased costs. These reasons are discussed in more detail below.
- Net income of $117 million for the third quarter was $48 million lower than for the same period in the previous year. The primary reason for the decline in net income is a decrease in margins of $40 million. This is primarily due to higher energy costs, due largely to lower-than-normal water inflows in the region, which reduces the energy available from low-cost hydro generation in the region. An increase of $16 million in maintenance expenses is largely due to timing of maintenance expenditures on the distribution and generation systems and increased system restoration costs due to province-wide storms in October. A decrease in finance charges of $5 million due to the decline in interest rates, partly offset the increased costs. The reasons for the decrease in net income for the third quarter are discussed in more detail below.

Domestic Revenues

- Domestic revenues of $701 million for the three months ended December 31, 2003 were $32 million higher than for the same period in the previous year. This increase is due a larger base of residential customers and to cooler-than-normal temperatures in October and November. Temperatures were 16 per cent below normal in October and 18 per cent below normal in November.
- Domestic revenues of $1,849 million for the nine months ended December 31, 2003, were $55 million higher than for the same period in the previous year. Residential revenues increased by $34 million over the same period in the previous year due to the addition of approximately 20,000 new customers and to an increase in consumption as a result of higher-than-normal temperatures in July and August and to cooler-than-normal temperatures in October and November. Revenues from light industrial and commercial customers increased $14 million, mainly due to customer growth and an increase in cooling demand over the summer. Customer growth in the residential and commercial sectors was slightly higher than the average customer growth over the last five years. The increase in large industrial revenues of $6 million, due to

higher production in the pulp and paper sector, also contributed to the increase in domestic revenues.

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 engaged in electricity trade, BC Hydro ensures that its ability to meet its domestic supply 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 for the three months ended December 31, 2003, were $454 million, a decrease of $23 million from the same period in the prior year. The decrease was due to lower volumes and a lower average sales price than in the same period last year. Electricity trade revenues for the nine months ended December 31, 2003, were $1,531 million, an increase of $100 million from the same period in the previous year. The increase was primarily due to an increase in average sale price, which rose 13 per cent from $53/MW·h last year to $60/MW·h this year. The increase in market prices is caused by several factors, including lower energy available from low-cost hydro generation in the region and tighter natural gas supplies. The increase in revenue due to higher average sale prices was partly offset by a five-per-cent reduction in sales volumes, from 24,438 GW·h in the prior year to 23,255 GW·h in the current year. The decrease in sales volumes was due primarily to lower reservoir levels and transmission restrictions between B.C. and the United States.

Energy Costs

Energy costs are made up of the following sources of supply:

	For the three months ended December 31					
	(in millions)		(in GW·h)		($/MW·h)	
	2003	2002	**2003**	2002	**2003**	2002
Hydro[1]	**$70**	$76	**12,332**	13,994	**$5.7**	$5.4
Purchases from Independent Power Producers and other long-term purchase contracts	**97**	80	**1,638**	1,266	**59.2**	63.2
Other electricity purchases	**378**	349	**7,883**	6,263	**47.9**	55.7
Natural gas[2]	**59**	61	**111**	101	**102.7**	93.1
Non-integrated	**4**	3	**9**	27	**444.4**	111.1
Transmission charges and other expenses	**26**	16				
Total	**$634**	$585	**21,973**	21,651	**$28.9**	$27.0

Energy Costs

Energy costs are made up of the following sources of supply:

	For the nine months ended December 31 (in millions)		(in GW·h)		($/MW·h)	
	2003	2002	**2003**	2002	**2003**	2002
Hydro[1]	**$179**	$188	**31,160**	33,905	**$5.7**	$5.5
Purchases from Independent Power Producers and other long-term purchase contracts	**281**	227	**4,682**	3,943	**60.0**	57.6
Other electricity purchases	**1,321**	1,127	**26,655**	25,225	**49.6**	44.7
Natural gas[2]	**144**	121	**323**	318	**108.8**	80.2
Non-integrated	**10**	9	**49**	69	**204.1**	130.4
Transmission charges and other expenses	**91**	80				
Total	**$2,026**	$1,752	**62,869**	63,460	**$32.2**	$27.6

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

2 Includes costs of remarketed gas of approximately $109 million for the nine months ended December 31, 2003, compared with $95 million for the same period in the previous year. 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 and $ per MW.h is calculated excluding remarketed gas.

- 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 for the three months ended December 31, 2003, were $49 million higher compared with the same period in the previous year. These increases reflect the impact of lower water inflow levels into BC Hydro reservoirs and the resulting reduction in the amount of low-cost hydro generated. A greater amount of higher cost import energy was therefore purchased. Energy costs for the nine months ended December 31, 2003, were $274 million higher compared with the same period in the previous year, due to the low water inflow and higher energy purchase prices. BC Hydro's electricity imports to meet its domestic load requirements for the nine months ended December 31, 2003, were 3,739 GW·h, whereas no imports were required for the same period of the previous year. The increase in electricity market prices was caused by several factors including lower hydro availability and tighter natural gas supplies.
- Water inflows into BC Hydro's reservoirs were 10 per cent lower at December 31, 2003 than at December 31, 2002. This resulted in a reduction in reservoir levels and the volume of low-cost hydro generation. The combined storage in BC Hydro reservoirs at December 31, 2003 was 99 per cent of average (2002 — 100 per cent). Average storage levels relate to the average from 1985 to 2002. The Williston Reservoir on the Peace river system was 102 per cent of average (2002 — 110 per cent) and the Kinbasket Reservoir on the Columbia River system was 82 per cent of average (2002 — 75 per cent).
- BC Hydro chose to import energy for domestic use and conserve reservoir levels, as it was

more economic than generating additional energy from its hydro and thermal facilities. 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 during certain periods. BC Hydro currently anticipates importing approximately 5,000 GW·h for domestic use this year, approximately nine per cent of its domestic load.

- Maintenance expenses of $81 million for the three months ended December 31, 2003, were $16 million higher than for the same period in the previous year. The increase in maintenance expenses is largely due to timing of maintenance expenditures on the distribution and generation systems and increased system restoration costs due to province-wide storms in October. Maintenance expenses of $225 million for the nine months ended December 31, 2003, were $51 million higher, due primarily to increases in maintenance performed as result of forest fire damage and system restoration due to storms ($17 million) and to routine maintenance being performed earlier this year ($7 million). Another factor that contributed to the increase in maintenance was higher employee future benefit costs (primarily pension costs) of approximately $8 million as a result of the increase in the pension liability, which is based on the September 2002 actuarial valuation of BC Hydro's pension plans. The most recent actuarial valuation reflected increased obligations as a result of several factors, such as employees retiring earlier and living longer.
- Operations and administration expenses of $226 million, for the nine months ended December 31, 2003, were $13 million higher than for the same period in the previous year. The increase is largely due to one-time expenditures related to implementation costs for IT projects ($7 million) and initial set-up costs relating to BCTC ($7 million).

Taxes

- Taxes, which consist of school taxes and grants-in-lieu of taxes, were $37 million for the three months ended December 31, 2003. Taxes were similar to the same period in the prior year. Taxes were $108 million for the nine months ended December 31, 2003, a decrease of $3 million from the same period in the previous year.

Finance Charges

- Finance charges for the three months ended December 31, 2003, were $5 million lower than for the same period in the previous year. Finance charges for the nine months ended December 31, 2003, were $30 million lower than for the same period in the previous year. This was primarily due to a stronger Canadian dollar, which impacted the cost of interest payments on U.S. dollar denominated debt. The Canadian dollar for the nine months ended December 31, 2003, averaged U.S.$0.7370, compared with U.S.$0.6406 for the same period in the previous year. Lower short-term interest rates and higher sinking fund income also contributed to the reduction in finance charges.

Liquidity and Capital Resources

- Cash flow provided by operating activities for the third quarter ended December 31, 2003, was $251 million, compared with $366 million for the same period in the previous year. The decrease in cash flow from operating activities of $115 million is the result of reduced net income from operations and a decrease in operating working capital primarily due to a reduction in energy purchase accounts payable.

- Cash flow provided by operating activities for the nine months ended December 31, 2003, was $423 million, compared with $614 million for the same period in the previous year. The decrease in cash flow from operating activities of $191 million is primarily the result of reduced net income.
- Capital expenditures, including demand-side management programs, as shown in the schedule below for the three and nine months ended December 31 were:
- Generation-related expenditures decreased, primarily due to reduced expenditures for the Vancouver Island Generation Project (VIGP). Expenditures for VIGP were lower than in the same period in the prior year due to the decision from the British Columbia Utilities Commission (BCUC) to deny the Certificate of Public Convenience and Necessity (CPCN) for the project (see Note 5 in the notes to the interim Consolidated Financial Statements and further explanations below). The decrease in general expenditures is primarily due to lower expenditures on computer projects in 2003 due to the completion in the previous year of a major implementation of an integrated information system.

	For the three months ended December 31		**For nine months ended December 31**	
(in millions)	**2003**	2002	**2003**	2002
Generation replacements and expansion	**$34**	$56	**$99**	$177
Transmission lines and substation replacements and expansion	**48**	37	**132**	116
Distribution improvements and expansion	**52**	43	**144**	121
General–computers, vehicles, etc.	**17**	31	**58**	91
Change in working capital related to capital asset expenditures[1]	**1**	3	**38**	23
Capital asset expenditures per Consolidated Statement of Cash Flows	**152**	170	**471**	528
Power Smart (Demand-side management)	**21**	9	**40**	28
Total capital expenditures per Consolidated Statement of Cash Flows	**$173**	$179	**$511**	$556

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

- During the three months ended December 31, 2003, BC Hydro did not issue or retire any long-term debt. During the nine months ended December 31, 2003, BC Hydro issued four new bonds, for a total of $640 million. The funds from these issues, together with an increase in revolving borrowings, were used to redeem a $300-million bond and to fund the payment to the Province and capital expenditures. The net long-term debt balance (net of sinking funds) at December 31, 2003, was $6,970 million, compared with $6,849 million at March 31, 2003. The increase in debt was partly offset by the impact of the stronger Canadian dollar, which reduced the Canadian equivalent of U.S. debt, by approximately $285 million.

Vancouver Island Gas Pipeline

- On September 8, 2003, the British Columbia Utilities Commission (BCUC) issued a decision that denied BC Hydro's application for a Certificate of Public Convenience and Necessity for the proposed Vancouver Island Generation Project (VIGP). VIGP is the proposed power plant on Vancouver Island. The BCUC agrees with BC Hydro that new electricity supply will be required on Vancouver Island for the 2007/2008 heating season. As offered by BC Hydro and accepted by the BCUC, a Call for Tender (CFT) process has been initiated to meet the expected Vancouver Island demand. BC Hydro released the CFT on October 31, 2003, and by the closing date on November 14, 2003, 23 bidders had registered. BC Hydro's target for the CFT is to acquire 150 to 300 megawatts, aggregate, of low-cost, new dependable capacity on Vancouver Island. Individual projects must employ proven technology, be at least 25 megawatts in size and reach commercial operation by May 2007. The outcomes of the CFT will be announced August 31, 2004.
- On January 23, 2004, BC Hydro received a response from the BCUC regarding the CFT process. BC Hydro is presently evaluating the issues addressed in the BCUC response, including issues related to evaluation criteria for the CFT.

Georgia Strait Crossing

- The Georgia Strait Pipeline Crossing (GSX) is a joint project sponsored by BC Hydro and Williams Gas to construct a natural gas pipeline from the Huntingdon/Sumas supply hub to Vancouver Island. GSX was designed as a large-capacity pipeline with capability to provide gas transportation service to the Island Cogeneration Plant (ICP), the planned Vancouver Island Cogeneration Project (VIGP), a third gas-fired generation plant on Vancouver Island and other large industrial gas consumers along its route through the United States.
- GSX received its Certificate of Public Convenience and Necessity from the National Energy Board in December 2003 and U.S. Federal Energy Regulatory Commission approval was received in September 2002. Additional provincial, federal and U.S. approvals are required, but these are expected to have a lower risk profile.
- The project, however, is also contingent upon development of VIGP or a similar large gas-fired generation plant on Vancouver Island with a demand of approximately 45Tj per day. GSX is not required if VIGP or a similar large gas-fired generation project is not successful in the Vancouver Island Call for Tender (VI CFT), as Terasen Gas can provide all necessary firm gas transportation service to ICP and other small gas-fired generation with upgrades to its existing gas pipeline system.
- An alternative to GSX for gas transportation service has been proposed by a third party if VIGP is successful in the VI CFT. This alternative would also meet the gas transportation

requirements for ICP. BC Hydro is comparing the costs of the GSX and this alternative and assessing the legal, regulatory and development risks associated with both alternatives. BC Hydro has also requested that the third party provide the basis for its cost estimates to supply gas transportation from the terminus of GSX to VIGP and ICP. Similar discussions in this regard have also taken place between BC Hydro and the BCUC.

- BC Hydro's carrying costs of VIGP and GSX presently recorded as an asset on the balance sheet, which include legal, regulatory, administrative and engineering costs, are $67 million and $28 million, respectively. At December 31, 2003 the total shared project costs spent by Williams and BC Hydro was $44 million. BC Hydro has recorded its proportionate share of these costs in the asset amount of $28 million recorded on the balance sheet. In the event the GSX project is terminated, an additional fee of $5 million is payable by BC Hydro. With the uncertainty surrounding the GSX and VIGP projects, the recovery of these costs is uncertain and dependent on the future decision of the BCUC, who will determine the treatment to be given these costs.

Revenue Requirement Application

- On December 15, 2003, BC Hydro submitted its revenue requirement application to the British Columbia Utilities Commission (BCUC) requesting a general rate increase of 7.23 per cent effective April 1, 2004 and a further, 2.0 per cent increase effective April 1, 2005. On January 23, 2004, the BCUC approved the first rate increase of 7.23 per cent, on an interim basis effective April 1, 2004. A full public hearing will take place in May 2004 and a final decision is expected by fall 2004. If the BCUC does not approve the full amount of the requested increase, the difference will be fully refunded to customers with interest.
- Although electricity rates have not increased in the last 10 years, costs did increase during that period and new electricity sources to meet increases in demand will be more expensive than the existing supply of large-scale hydroelectricity. In addition, operating costs, and the ongoing costs of maintaining infrastructure, have increased and will continue to increase, primarily as a result of BC Hydro's aging assets and general cost increases. While the BCUC will make the final decision on any increase, BC Hydro customers will continue to have one of the lowest electricity rate structures in North America.
- BC Hydro will be involved in additional regulatory activities with the BCUC throughout the coming year. They include a Rate Design Hearing and a proceeding involving the Wholesale Transmission Tariff for the new British Columbia Transmission Corporation.

Heritage Contract

- As disclosed in the second quarter report for the six months ended September 30, 2003, the BCUC released its *Report and Recommendations in the Matter of British Columbia Hydro and Power Authority and an Inquiry into a Heritage Contract for British Columbia Hydro and Power Authority's Existing Generation Resources and Regarding Stepped Rates and Transmission Access* ("The Report").
- The report contained 27 recommendations to government to preserve the value of BC Hydro's existing, low-cost electricity generation for British Columbians. The recommendations were made after conducting a public process and a public hearing. On November 28, 2003, the Government accepted 22 of the recommendations and empowered the BCUC to deal with matters relating to the remaining five recommendations. These recommendations were taken into account in the revenue requirement application filed on December 15, 2003.

Green Power Generation

- In November 2003 BC Hydro signed agreements to purchase energy from 16 new private sector power projects to provide an additional 1,800 gigawatt hours per year to meet the energy needs of British Columbia. The investment from the private sector is estimated at $800 million. The energy, enough to meet the energy needs of 180,000 homes, will be purchased from Independent Power Producers (IPPs) that successfully bid into BC Hydro's 2002/2003 Green Power Generation (GPG) procurement process. Seventy IPPs submitted project proposals to BC Hydro's GPG call last December. The proposals were evaluated against publicly disclosed criteria. Thirty projects were short-listed, and their developers were invited to submit a bid to the call for tenders phase of the process. Sixteen IPPs tendered bids, which were adjusted to reflect various costs and benefits to BC Hydro associated with the project. All of these bids have been accepted and the IPPs have executed Electricity Purchase Agreements ranging from 10 to 20 years. The total net present value of these purchase commitments is estimated at close to $745 million. (See Note 4 to the interim Consolidated Financial Statements.)

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 helping California keep the lights on during the California energy crisis of 2000 and 2001. In the agreement the Trial Staff of FERC rejected California's claims that it was owed more than US$1 billion by Powerex. The agreement is subject to the approval by the full Commission and calls for further litigation to be suspended pending this approval. In return for suspension of these lengthy and complex proceedings, and to gain regulatory certainty and closure, Powerex has agreed to a payment of US$1.3 million once the settlement is approved. The payment is not related to any Powerex transactions and does not constitute an admission of any wrongdoing.
- As was disclosed in the notes to BC Hydro's 2003 Audited 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 uncollectable amounts and legal costs associated with the ongoing legal and regulatory impacts of the California energy crisis. These provisions, based on management's best estimates, are intended to provide for any remaining exposure.

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. In addition, the impact of the revenue requirement application decision by the BCUC on BC Hydro's earnings and operations will not be known until fall 2004.

- Management's assessment of business risk and uncertainties is ongoing and the risks and uncertainties to BC Hydro have not changed materially from the Management's Discussion and Analysis presented in the 2003 Annual Report.

Future Outlook

- BC Hydro's net income for this fiscal year is forecast to be $190 million before any transfers to/from the Rate Stabilization Account. 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 under plausible scenarios is estimated to be between $130 million and $220 million.

CONSOLIDATED STATEMENT OF OPERATIONS

	For the three months ended December 31 (Unaudited)		For the nine months ended December 31 (Unaudited)	
(in millions)	**2003**	2002	**2003**	2002
Revenues				
Residential	**$ 292**	$ 267	**$ 682**	$ 648
Light industrial and commercial	**235**	230	**674**	660
Large industrial	**135**	133	**391**	384
Other energy sales	**23**	25	**59**	60
Other sundry	**16**	14	**43**	42
	701	669	**1,849**	1,794
Electricity trade	**454**	477	**1,531**	1,431
	1,155	1,146	**3,380**	3,225
Expenses				
Energy costs	**634**	585	**2,026**	1,752
Maintenance	**81**	65	**225**	174
Operations and administration	**63**	70	**226**	213
Taxes	**37**	37	**108**	111
Depreciation and amortization	**105**	101	**308**	302
	920	858	**2,893**	2,552
Income Before Finance Charges	**235**	288	**487**	673
Finance charges	**118**	123	**337**	367
Net Income	**$ 117**	$ 165	**$ 150**	$ 306

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the nine months ended December 31 (in millions)	**2003** ***(Unaudited)***	2002 *(Unaudited)*
Retained earnings, beginning of period	**$ 1,609**	$ 1,529
Net income	**150**	306
Payment to the Province	**(115)**	(246)
Retained earnings, end of period	**$ 1,644**	$ 1,589

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEET

(in millions)	***as at December 31*** **2003** (Unaudited)	*as at March 31* 2003 *(Audited)*
ASSETS		
Capital Assets		
Capital assets in service	**$15,033**	$14,940
Less accumulated depreciation	**5,969**	5,816
	9,064	9,124
Unfinished construction	**848**	669
	9,912	9,793
Current Assets		
Temporary investments	**59**	4
Accounts receivable and accrued revenue	**360**	362
Materials and supplies	**95**	88
Prepaid expenses	**32**	86
Unrealized gains on mark-to-market transactions	**3**	10
	549	550
Other Assets and Deferred Charges		
Loan receivable	**23**	23
Sinking funds	**1,020**	1,037
Demand-side management programs	**145**	123
Deferred debt costs	**154**	385
Foreign currency contracts	**–**	13
	1,342	1,581
	$11,803	$11,924
LIABILITIES AND EQUITY		
Long-Term Debt		
Long-term debt net of sinking funds	**$ 6,970**	$ 6,853
Sinking funds presented as assets	**1,020**	1,037
	7,990	7,890
Foreign Currency Contracts	**77**	15
Current Liabilities		
Accounts payable and accrued liabilities	**547**	689
Accrued interest	**134**	108
Accrued payment to the Province	**115**	338
Unrealized losses on mark-to-market transactions	**3**	10
	799	1,145
Deferred Credits and Other Liabilities		
Provision for future removal and site restoration costs	**189**	174
Deferred revenue	**282**	258
Rate stabilization account	**21**	21
Contributions arising from the Columbia River Treaty	**196**	203
Contributions in aid of construction	**605**	609
	1,293	1,265
Retained Earnings	**1,644**	1,609
	$11,803	$11,924

See accompanying notes to the interim consolidated financial statements.

L.I. (Larry) Bell
Chair and Chief Executive Officer

Alice Laberge
Chair, Audit and Risk Management Committee

CONSOLIDATED STATEMENT OF CASH FLOWS

	For the three months ended December 31 (Unaudited)		*For the nine months ended December 31 (Unaudited)*	
(in millions)	**2003**	2002	**2003**	2002
Operating Activities				
Net income	**$ 117**	$ 165	**$ 150**	$ 306
Adjustments for:				
– Depreciation and amortization	**105**	101	**308**	302
– Other non-cash items	**34**	39	**26**	51
	256	305	**484**	659
Working capital changes	**(5)**	61	**(61)**	(45)
Cash provided by operating activities	**251**	366	**423**	614
Investing Activities				
Loan receivable	**(1)**	–	**(2)**	(8)
Capital asset expenditures	**(152)**	(170)	**(471)**	(528)
Contributions in aid of construction	**14**	17	**35**	52
Demand-side management programs	**(21)**	(9)	**(40)**	(28)
Future removal and site restoration costs	**(4)**	(3)	**(7)**	(9)
Proceeds from property sales	–	–	–	1
Cash provided by investing activities	**(164)**	(165)	**(485)**	(520)
Financing Activities				
Bonds, notes and debentures:				
– Issued	**–**	**–**	**640**	1,007
– Retired	**–**	**–**	**(300)**	(579)
Revolving borrowings	**(49)**	(166)	**102**	(94)
Sinking fund changes	**(8)**	(8)	**(5)**	13
Premium, discount and issue costs	**–**	**–**	**7**	3
Proceeds from early settlement of interest rate swaps	**11**	**–**	**11**	22
Cash provided by financing activities	**(46)**	(174)	**455**	372
Payment to the Province	**–**	–	**(338)**	(333)
Increase in cash	**41**	27	**55**	133
Cash, beginning of period[1]	**18**	123	**4**	17
Cash, end of period[1]	**$ 59**	$ 150	**$ 59**	$ 150
Supplemental disclosure of cash flow information				
– Interest paid	**$ 108**	$ 113	**$ 369**	$ 376

See accompanying notes to the interim consolidated financial statements.

[1]Cash at the beginning and end of the period consists of temporary investments.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) DECEMBER 31, 2003

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 more than 74,500 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 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 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 Audited Consolidated Financial Statements and accompanying notes in BC Hydro's 2003 Annual Report.

The accounting policies used to prepare these interim consolidated financial statements conform to those described in the notes to BC Hydro's 2003 Audited Consolidated Financial Statements.

On April 1, 2003, BC Hydro adopted the new recommendations in AcG-14 of the CICA Handbook "Disclosure of Guarantees" (see Note 3). In addition, BC Hydro changed the basis under which it has disclosed certain segmented information, which is described in Note 8 to the financial statements.

The CICA has issued Accounting Guideline 13, "Hedging Relationships" ("AcG-13"), which will be effective for years beginning on or after July 1, 2003. AcG-13 addresses identification, designation, documentation and effectiveness of hedging transactions for purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guidelines, BC Hydro will be required to document its hedging relationships and explicitly demonstrate that the hedges are highly effective in order to continue accrual accounting for derivatives that are part of a hedging relationship. BC Hydro is evaluating the impact of adopting this guideline on its financial statements.

In June 2003 the CICA issued Accounting Guideline 15, "Consolidation of Variable Interest Entities" ("AcG-15"). AcG-15 clarifies the application of consolidation principles to certain entities in which equity interests do not have the characteristics of a "controlling financial interest" or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. The purpose of AcG-15 is to provide guidance for determining when a company includes the assets, liabilities and results of activities of such an entity (a "variable interest entity") in its consolidated financial statements. AcG-15 applies to annual and interim periods beginning on or after November 1, 2004, although earlier application is encouraged. BC Hydro is evaluating the impact of adopting this guideline on its financial statements.

In March 2003 the CICA issued the new Handbook Section 3110, "Asset Retirement Obligations" ("Section 3110"), which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. It applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and (or) the normal operation of a long-lived asset, except for certain obligations of lessees. Section 3110 amends Section 3061, "Property, Plant, and Equipment", and requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, an entity capitalizes the cost by increasing the carrying amount of the related long-lived assets. Over time, the liability is accreted to its present value each period, and the capitalized cost is amortized over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement.

An asset retirement obligation may result from the acquisition, construction, development and (or) the normal operation of a long-lived asset that has an indeterminate useful life and thereby an indeterminate settlement date for the asset retirement obligation. Uncertainty about the timing of settlement of the asset retirement obligation does not remove that obligation from the scope of Section 3110, but will affect the measurement of a liability for that obligation and possibly the timing of recognition of the liability. In such cases, the liability is initially recognized in the period in which sufficient information exists to estimate a range of potential settlement dates that is needed to employ a present value technique to the estimated fair value of the obligation.

Section 3110 is effective for fiscal years beginning on or after January 1, 2004. BC Hydro is currently evaluating the impact of adopting Section 3110 on its financial statements. Section 3110 replaces the Guideline on Future Restoration and Site Removal previously found in Section 3061. Section 3110 is applied retroactively with restatement of prior years.

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 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 inflow levels, energy consumption demand levels within the region, and market prices of energy, can have a significant impact on BC Hydro's operating results.

Note 3: Guarantees and Indemnities

In addition to the guarantees and indemnities disclosed in BC Hydro's Notes to its 2003 Audited Consolidated Financial Statements, BC Hydro has indemnified Williams Gas Pipeline Company, LLC ("Williams") for their 50-per-cent share of the aggregate project development costs of the Georgia Strait Crossing Pipeline Project (GSX) if there is a failure to obtain regulatory approval from any Canadian federal, provincial or local Regulatory Authority by March 15, 2004. In July 2003 the Joint Review Panel (JRP) of Canada's National Energy Board (NEB) and the Canadian Environmental Assessment Agency (CEAA) issued its report relating to the environmental assessment of GSX. The JRP recommended that GSX proceed to the next level of decision-making. In December 2003 GSX received its Certificate of Public Convenience and Necessity from the National Energy Board. As of December 31, 2003, the total of the shared project costs spent by Williams and BC Hydro was $44 million. In September 2003 the British Columbia Utilities Commission (BCUC) decision to deny a Certificate of Public Convenience (CPCN) for the Vancouver Island Generation Project (VIGP) (see Note 5) may impact the future of GSX (see Note 6). In the event of termination an additional fee of $5 million is payable by BC Hydro. Negotiations with Williams to amend the existing agreements are ongoing and BC Hydro's potential liability is uncertain at this time. Accordingly, no provisions have been made in these interim consolidated financial statements.

Note 4: Commitments and Contingencies

In November 2003 BC Hydro signed energy purchase agreements with the private sector to purchase energy to meet a portion of its expected annual electricity requirements. Sixteen new power projects under BC Hydro's 2002/2003 Green Power Generation procurement process were awarded to Independent Power Producers to provide BC Hydro with an additional 1,800 gigawatt hours per year. The minimum obligation to purchase energy under these contracts have an estimated net present value of $745 million. Payments for the next five years are approximately (in millions):

- 2005 $1
- 2006 $8
- 2007 $59
- 2008 $100
- 2009 $101

As disclosed in the notes to BC Hydro's 2003 Audited Consolidated Financial Statements, on December 2, 2001, Enron Corp. ("Enron") and certain of its subsidiaries filed for bankruptcy protection. As a result, the long-term Power Purchase Agreement between Powerex and Enron terminated. Under a 1997 agreement between Alcan, Enron Power Marketing Inc. (EPMI), Powerex and BC Hydro, Alcan agreed to remain liable to Powerex for the payment obligations of EPMI, for which Alcan was originally responsible. Alcan has not paid this obligation, so Powerex took the matter to arbitration. An arbitration award was issued on January 17, 2003, which required Alcan to pay Powerex US$100 million within 30 days, with interest accruing thereafter. This payment currently remains outstanding and Powerex has commenced enforcement proceedings in British Columbia.

Alcan successfully applied to have the B.C. enforcement proceeding adjourned pending the outcome of an application it made in the U.S. courts to have the arbitration award set aside. That application was heard in August 2003 before a U.S. magistrate, who recommended that the application be denied in a "Findings and Recommendation" issued on September 18, 2003. On December 11, 2003, a Judge of the U.S. District Court accepted this recommendation and issued a decision of the Court to that effect. On January 9, 2004, Alcan appealed this decision to the Ninth Circuit Court of Appeal. While this may result in further delay, Powerex has been advised that this risk is low and that the B.C. enforcement action should proceed without awaiting the outcome of the appeal. Accordingly, Powerex has now renewed its enforcement proceedings in British Columbia, expected to be heard sometime in the spring of 2004. At this time, the outcome of this claim is still not determinable. Accordingly, no recovery in respect of the arbitration award will be recorded in the interim consolidated financial statements until collection is assured.

There are no other material changes to the contingencies disclosed in the notes to BC Hydro's 2003 Audited Consolidated Financial Statements.

Note 5: Vancouver Island Generation Project

On September 8, 2003, the BCUC issued a decision that denied BC Hydro's application for a CPCN for the proposed VIGP (the proposed power plant on Vancouver Island). The BCUC agrees with BC Hydro that new electricity supply will be required on Vancouver Island for the 2007/2008 heating season and, therefore, they have recommended that BC Hydro proceed with a Call for Tender (CFT) process to meet the expected Vancouver Island demand. BC Hydro released the CFT on October 31, 2003, and by the closing date on November 14, 2003, 23 bidders had registered. BC Hydro's target for the CFT is to acquire 150 to 300 megawatts, aggregate, of low-cost, new dependable capacity on Vancouver Island. Individual projects must employ proven technology, be at least 25 megawatts in size and reach commercial operation by May 2007. The outcomes of the CFT will be announced by August 31, 2004.

On January 13, 2004, BC Hydro received a response from the BCUC regarding the CFT process. BC Hydro is presently evaluating the issues addressed in the BCUC response, including issues related to evaluation criteria for the CFT.

Note 6: Georgia Strait Crossing

The GSX is a joint project sponsored by BC Hydro and Williams to construct a natural gas pipeline from the Huntingdon/Sumas supply hub to Vancouver Island. GSX was designed as a large-capacity pipeline with capability to provide gas transportation service to the Island Cogeneration Plant (ICP), the planned VIGP, a third gas-fired generation plant on Vancouver Island and other large industrial gas consumers along its route through the United States.

GSX received its CPCN from the NEB in December 2003 and U.S. Federal Energy Regulatory Commission approval was received in September 2002. Additional provincial, federal and U.S. approvals are required, but these are expected to have a lower risk profile.

The project, however, is also contingent upon development of VIGP or a similar large gas-fired generation plant on Vancouver Island with a demand of approximately 45Tj per day. GSX is not required if VIGP or a similar large gas-fired generation project is not successful in the Vancouver Island Call for Tender (VI CFT), as Terasen Gas can provide all necessary firm gas transportation service to ICP and other small gas-fired generation with upgrades to its existing gas pipeline system.

An alternative to GSX for gas transportation service has been proposed by a third party if VIGP is successful in the VI CFT. This alternative would also meet the gas transportation requirements for ICP. BC Hydro is comparing the costs of the GSX and this alternative and assessing the legal, regulatory and development risks associated with both alternatives. BC Hydro has also requested that the third party provide the basis for its cost estimates to supply gas transportation from the terminus of GSX to VIGP and ICP. Similar discussions in this regard have also taken place between BC Hydro and the BCUC.

At this time it remains prudent for BC Hydro to continue to support the GSX opportunity.

BC Hydro's carrying costs of VIGP and GSX, which include legal, regulatory, administrative and engineering costs, are $67 million and $28 million, respectively. The recovery of these costs is uncertain and dependent on the future decision of the BCUC, who will determine the treatment to be given these costs.

Note 7: Transaction with British Columbia Transmission Corporation

Pursuant to *Energy For Our Future: A Plan for B.C.*, the Province, the sole shareholder of BC Hydro, approved the transfer of the transmission operations of BC Hydro to British Columbia Transmission Corporation (BCTC), a company wholly owned by the Province. The ultimate objective of the transaction is to transfer the management, maintenance and operation of the high-voltage electric system in British Columbia to BCTC and provide transparent open-access transmission services. The Transmission Corporation Act, enacted on May 29, 2003, will govern BCTC's role of managing, maintaining and operating BC Hydro's transmission system.

BC Hydro will consolidate BCTC until BCTC is operationally and financially independent of BC Hydro. It is expected that BCTC will remain operationally dependent on BC Hydro until the BCUC approves rates for the activities for which

BCTC is directly responsible and BCTC is sufficiently capitalized by the Province to finance its operations.

In mid-2004, BCTC and BC Hydro will make a joint filing to the British Columbia Utilities Commission (BCUC) to set the rates charged for the use of the transmission system. The filing will set BCTC's rates for the management, maintenance and operation of the transmission assets and grid operations and set a separate rate for BC Hydro for asset ownership costs and a return on equity for the transmission assets. Until these rates are set by the BCUC, BC Hydro will pay BCTC for the management, maintenance, and operation of the transmission assets.

On July 16, 2003, BC Hydro signed an Interim Transition Agreement with BCTC to begin the transfer of the transmission operations of BC Hydro to BCTC. On August 1, 2003, BC Hydro permanently transferred to BCTC 260 employees responsible for managing and operating the transmission grid and planning the capital expenditures for the related assets. In November 2003 the final service agreements (the Key Agreements) were approved by the Province. The approval of the Key Agreements effectively terminated the Interim Transition Agreement.

Under the Interim Transition Agreement, for the period August 1, 2003, to November 30, 2003, BCTC operated the transmission business on behalf of BC Hydro for a service fee on a cost-recovery basis. Under the Key Agreements, for the period from December 1, 2003, to the commencement date of BCTC's own transmission tariff, BCTC will operate the transmission business on behalf of BC Hydro for a service fee to cover BCTC's cost of operations and a return on equity.

For the three months ended December 31, 2003, BCTC charged BC Hydro service fees totalling $14 million. In addition, BC Hydro agreed to reimburse expected structuring, legal and other advisory costs incurred by BCTC. For the three months ended December 31, 2003, BCTC was reimbursed $1 million for these costs. The total amount of BCTC's cost of operations and the reimbursement of structuring and advisory costs is currently estimated at approximately $60 million for fiscal 2004. In August 2003 BC Hydro provided a loan in the amount of $5 million to fund capital acquisitions by BCTC. This loan was non-interest-bearing and was repaid in December 2003.

Upon direction from the Province, BC Hydro declared and paid a special dividend in the amount of $20 million to the Province in November 2003. The funds were then contributed by the Province to BCTC as an equity contribution. The equity contribution, along with third-party financing, will be used by BCTC to acquire approximately $50.7 million of assets and facilities related to operation and control of the transmission system from BC Hydro at carrying value. BC Hydro will continue to own the transmission system assets and will be responsible for funding all future additions and sustaining investments in these assets based on directions from BCTC in its capacity of asset manager.

Note 8: Segmented Information

The segmented information for the three and nine months ended December 31, 2003, reflects changes from the segmented information disclosed in BC Hydro's 2003 Audited Financial Statements. The segmented information in the prior year has been reclassified to reflect these changes. The changes were made to reflect the proposals contained within the Heritage Contract proposal filed with the British Columbia Utilities Commission in April 2003 and to reflect changes in the Accountability Framework used for internal management reporting, risk management and performance measurement purposes. The changes relate to the following:

- Powerex pays its net income, excluding unrealized gains/losses, to Generation as a dividend. In the prior year, Powerex paid only a portion of its net income to Generation based on factors such as the amount of income earned on its trade books. Powerex's dividend to Generation for the three months ended December 31, 2003, was $6 million, compared with $26 million for the same period in the prior year. For the nine months ended December 31, 2003, the Powerex dividend to Generation was $96 million, compared with $42 million in the prior year.

- Powerex's energy costs include an allocation of BC Hydro's cost of purchases of point-to-point transmission within B.C. for export and most import transactions. These costs, totalling $12 million for the three months ended December 31, 2003, and $39 million for the nine months ended December 31, 2003, were not deducted from Powerex's income in the prior year.
- Generation's revenue in the nine months ended December 31, 2002, included the recovery from Distribution of the costs relating to energy purchases from Independent Power Producers (IPPs) and other long-term purchase commitments. These energy purchases were managed by Generation and the costs included in setting the transfer price for energy between Generation and Distribution. Effective April 1, 2003, energy purchases from IPPs and other long-term purchase commitments are managed by Distribution. These purchase costs, excluding gas costs, are now shown as direct costs to Distribution and no longer enter into the transfer price between Generation and Distribution. The costs of these purchases for the three months ended December 31, 2003, totalled $75 million, compared with $59 million for the same period in the prior year. The costs of these purchases for the nine months ended December 31, 2003, were $213 million, compared with $185 million in the prior year.
- The Transmission segment at December 31, 2003, includes amounts that have been consolidated from British Columbia Transmission Corporation (BCTC) due to operational dependence on BC Hydro (see note 7). The BCTC amounts included in the Transmission segment at December 31, 2003 are as follows:

Assets	$81.2 million
Liabilities	$55.0 million
Equity	$26.2 million

Three months ended December 31, 2003

(in millions)	Distribution	Transmission	Generation	Powerex	Other[4]	Consolidation Adjustments/ Eliminations	Total
	$	$	$	$	$	$	$
External revenues	687	4	4	437	10	13[3]	1,155
Inter-segment revenues	–	164	372	98	107	(741)	–
Net income (loss)	(60)	35	111	4	14	13[3]	117
Total assets	3,416	3,101	4,794	440[1]	454[2]	(402)	11,803

Nine months ended December 31, 2003

(in millions)	Distribution	Transmission	Generation	Powerex	Other[4]	Consolidation Adjustments/ Eliminations	Total
	$	$	$	$	$	$	$
External revenues	1,807	9	12	1,515	31	6[3]	3,380
Inter-segment revenues	–	495	1,060	341	308	(2,204)	–
Net income (loss)	(268)	118	284	93	21	(98)[3]	150

Three months ended December 31, 2002

(in millions)	Distribution	Transmission	Generation	Powerex	Other[4]	Consolidation Adjustments/ Eliminations	Total
	$	$	$	$	$	$	$
External revenues	639	2	19	518	6	(38)[3]	1,146
Inter-segment revenues	–	203	359	39	138	(739)	–
Net income (loss)	49	75	95	67	(65)	(56)[3]	165
Total assets	3,221	3,131	4,900	493[1]	724[2]	(345)	12,124

Nine months ended December 31, 2002

(in millions)	Distribution	Transmission	Generation	Powerex	Other[4]	Consolidation Adjustments/ Eliminations	Total
	$	$	$	$	$	$	$
External revenues	1,720	7	42	1,486	31	(61)[3]	3,225
Inter-segment revenues	–	595	943	169	443	(2,150)	–
Net income (loss)	47	220	140	175	(149)	(127)[3]	306

1 Includes inter-segment receivables of $289 million ($202 million for nine months ended December 31, 2002).

2 Mainly consists of capital assets such as office buildings, vehicles and computer equipment.

3 These adjustments mainly relate to the difference between BC Hydro's management reporting, used for risk management and performance measurement purposes, and Generally Accepted Accounting Principles (GAAP). For management reporting purposes, energy purchases bought for future resale are expensed when the energy is sold. The energy purchased for future resale is also marked to market each month. For GAAP reporting purposes, energy purchases bought for future resale are expensed in the period of purchase. Under GAAP reporting, Powerex's net income was $21 million and income from domestic sources was $96 million for the three months ended December 31, 2003, compared with Powerex's net income of $25 million and income from domestic sources of $140 million for the same period in the previous year. For the nine months ended December 31, 2003, Powerex's net income under GAAP was $113 million and income from domestic sources was $37 million, compared with Powerex's net income of $120 million and income from domestic sources of $186 million in the prior year.

4 The prior year includes Engineering Services, Field Services and Shared Services Organizations , other Subsidiaries including Westech and Powertech, and Corporate costs. The functions within Shared Services and Westech were outsourced to Accenture Business Services of British Columbia (ABS) effective April 1, 2003.

Note 9: Subsequent Events

On December 15, 2003, BC Hydro filed a Revenue Requirement Application with the BCUC that included proposed rate increases of 7.23 per cent in fiscal 2005 and 2.0 per cent in fiscal 2006. On January 23, 2004, the BCUC approved BC Hydro's proposed interim rate increase of 7.23 per cent. The increase will be effective April 1, 2004. If the BCUC does not approve the full amount of the requested increase, the difference will be fully refunded to customers with interest.

OPERATING HIGHLIGHTS

	For the three months ended December 31 (Unaudited)		*For the nine months ended December 31 (Unaudited)*	
(in GW·h)	**2003**	2002	**2003**	2002
Electricity Sold				
Residential	**4,797**	4,390	**11,041**	10,483
Light industrial and commercial	**4,435**	4,337	**12,693**	12,424
Large industrial	**3,972**	3,893	**11,505**	11,255
Other energy sales	**565**	527	**1,205**	1,118
	13,769	13,147	**36,444**	35,280
Electricity trade	**7,103**	7,118	**23,255**	24,438
	20,872	20,265	**59,699**	59,718
Number of domestic customers			**1,646,075**	1,624,555
Number of employees			**4,161**[1]	5,943

1 Includes full-time and part-time employees. At April 1, 2003, approximately 1,600 employees were transferred to Accenture Business Services of British Columbia. On August 1, 2003, BC Hydro transferred approximately 260 employees to British Columbia Transmission Corporation.

3. PERFORMANCE MEASURES – BC HYDRO OVERALL

BC Hydro will accomplish its vision of being North America's leading sustainable energy company by building on its solid base of clean, renewable hydropower assets, by employing a skilled and capable workforce, by delivering excellent financial and operational performance, and by attaining strong public support. The company's four key goals reflect this ambition.

Strong financial performance — by targeting first-quartile (above the 75th percentile) costs when compared with similar utilities and striving to deliver stable earnings at the allowed Return on Equity.

Quality service — by focusing on customer satisfaction and service reliability.

Good environmental and social performance — by continuing to manage priority environmental and social issues.

Skilled workforce, safe workplace — by developing skills and knowledge of employees and contractors, and providing a safe, healthful, and harassment-free workplace.

Performance Measures, Targets, and Results

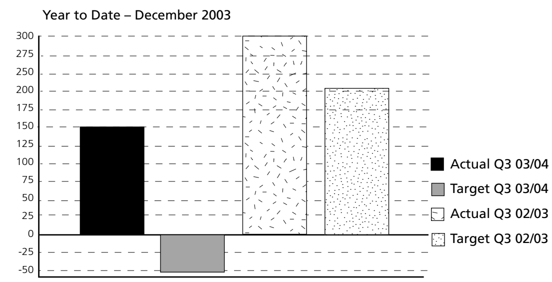
Performance measurement, both financial and non-financial, is an integral part of BC Hydro's Strategic Management Process. The development of performance measures is an evolving process. As business needs change, so also must the related measures change. Performance measures have been identified for the majority of BC Hydro's strategic objectives. The following report provides the results for BC Hydro's third-quarter 2003/2004 performance measures, as identified in the Service Plan against current targets and, where available, historical performance. Line of Business (business segments) measures are disclosed in the Line of Business sections.

Legend (for all Performance Measures)

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

Net Income (in millions) ▲

	Actual	Target
Q3 03/04	$150	$(41)
Q3 02/03	$306	$204



Net Income is defined as total revenue less total expenses before transfers to the Rate Stabilization Account. The targets are based on current cost and revenue drivers and the impact that cost reduction and/or revenue enhancement initiatives will have on these drivers. In recent years BC Hydro has experienced significant changes in net income due to extreme volatility in the electricity trade market. While such volatility has abated, its return would significantly impact the targets.

Net Income was better than target, primarily as a result of lower finance charges, an increase in electricity trade margins (the difference between what BC Hydro pays the market for electricity and what it gets for the electricity it sells to the market), and higher domestic revenues due largely to weather impacts. Finance charges were lower than Plan, mainly due to lower short-term interest rates and the strengthening of the Canadian dollar against the U.S. dollar. Net income is expected to remain ahead of target for the year due to these favourable factors.

Year-to-date Net Income was lower than for the same period in the previous year. The primary reason for the decline was the decrease in domestic margins resulting from the increasing cost of supply, due primarily to the increase in the market prices for energy. An increase in operations, maintenance and administration expenses, due largely to an increase in employee future benefit costs and one-time expenditures such as last summer's McLure forest fire and the set-up of the BC Transmission Corporation, added to the unfavourable variance. A decrease in finance charges partly offset the variance.

Reliability ▼

ASAI	Actual	Target
Q3 03/04	99.950%	99.970%
Q3 02/03	99.967%	99.970%

CAIDI	Actual	Target
Q3 03/04	2.93 hrs.	2.15 hrs.
Q3 02/03	2.34 hrs.	2.15 hrs.

Reliability is defined as a combination 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. These indices are electric utility industry standards. CAIDI and ASAI are reported on a rolling 12-month average. For the current results, this period was from January 1, 2003 to December 31, 2003.

CAIDI was worse than target, due to several major events that caused significant power interruptions to customers. In particular, reliability was adversely impacted by the McLure forest fire, which started during the night of July 31, damaging 20 kilometres of transmission line, putting the line out of service from the Heffley Creek Substation, 23 kilometres north of Kamloops, to Valemount. This source outage accounted for 761,636 customer-hours lost, or 10.7 per cent of the total customer-hours lost during this period. A summary of the major events during the 12-month period is given below.

For the nine months year-to-date, 5,341,776 customer-hours were lost, compared with the five-year average of 4,058,256 hours for the same period (April to December). Source outages accounted for 25 per cent of the customer-hours lost, largely due to the McLure forest fire. Other causes included trees (20 per cent), adverse weather (14 per cent), distribution equipment failures (13 per cent) and motor vehicle accidents (eight per cent).

The ASAI result means that over the 12-month period, the system was unavailable less than a total of 4.4 hours.

For more information about Reliability at BC Hydro please see pages 56-57.

Major events during the 12-month period of 2003

Date	Cause	Areas Affected	Customer Hours Lost	% of 12-Month Total
Jan 2–3, 2003	High winds & heavy rain	Lower Mainland & South Vancouver Island	546,715	7.6%
Mar 13, 2003	Windstorm	Lower Mainland & Vancouver Island	165,471	2.3%
Mar 22, 2003	High winds & lightning	Vancouver Island	189,199	2.7%
Jul 31, 2003	Source outage – McLure forest fire	South Interior	761,636	10.7%
Oct 28, 2003	Windstorm	Lower Mainland	294,000	4.1%

All Injury Frequency ▲

	Actual	Target
Q3 03/04	2.6	3.1

All Injury Frequency is defined as the total number of employee injury incidents (Medical Aids and Disabling Injuries) occurring in the 12 months prior to the report date relative to the number of worked hours in the same period. For this measurement, Medical Aid injuries are defined as those where a 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 injury.

For the year to date, the All Injury Frequency measure was better than target despite a bit of a recent levelling of the improvement rate. BC Hydro is still benefiting from the focus that has been placed on safety and performance improvement through awareness, planning, training and safe work practices. It is expected that the leveling trend will continue and it will become increasingly difficult to further reduce the frequency.

Notwithstanding the better-than-target performance, three electrical contact incidents, each causing significant injury, occurred this year — Wahleach Generating Station on June 18, of 2003, G.M. Shrum Generating Station on July 23, 2003, and Dal Grauer Substation on Oct. 3, of 2003. A review of these events was undertaken to determine if they had a common cause or trend. The review uncovered common causes and a number of corrective actions were undertaken as a result of the review that substantially reduce the risk of these incidents happening again.

For more information about Safety at BC Hydro please see page 67.

Environmental Regulatory Compliance ▲

	Actual	Target
Q3 03/04	6 Incidents	10 Incidents
Q3 02/03	6 Incidents	15 Incidents

Environmental Regulatory Compliance is defined as the number of externally reportable, preventable environmental incidents. An environmental incident is an incident that has caused, or has the potential for causing, one or more of the following:

- environmental damage
- adverse effect on fish, wildlife, air quality or other environmental resources
- adverse publicity with respect to environment
- legal or regulatory action (including ticketing) with respect to violation of statutes or environmental damage

The targets were derived from historical rates to allow for continued increased reporting resulting from greater awareness and utilization of BC Hydro's Environmental Incident Reporting system as well as increased pressure by regulatory agencies. After the education and awareness is complete, as well as improved relations and understanding with regulators, BC Hydro anticipates the numbers to start dropping. The reductions should result from continuously improving management practices.

Results are lower than the apportioned annual target for this quarter (10), but close to the normal quarter-to-quarter variability observed historically. Of the six incidents that qualified as preventable (four human error, two equipment failure) none was characterized as "severe". The year-to-date number of incidents (15) was also below target (30).

For this type of measure there is an inherent risk of unreported incidents. BC Hydro is currently reviewing its controls to attempt to ensure that all applicable incidents are reported.

Incremental Conservation Gigawatt Hours ●

	Actual	Target
Q3 03/04 YTD	586 GW·h	575 GW·h
Q3 02/03 YTD	162 GW·h	140 GW·h

Conservation Gigawatt Hours is defined as cumulative gigawatt hours 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 onstream. The targets include both residential and business demand-side management. If the targets are achieved, BC Hydro will rank in the top quartile both for energy savings as a percentage of domestic energy sales and for investment in demand-side management as a percentage of revenue (American Council for the Energy Efficient Economy).

The actual number of 586 GW.h 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 an incentive; 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. For the quarter, the actual number of 133 GW.h was slightly better than target (125 GW.h).

For more information about Power Smart at BC Hydro please see pages 47-48.

Approved Strategic Workforce Positions Filled ●

	Actual	Target
Q3 03/04 YTD	59	60

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.

For the year to date, the Strategic Workforce measure was on target. For the quarter, the actual came in at exactly the target (15). The year-end target of 80 is not expected to be met, due to organizational changes including the formation of the BC Transmission Corporation (BCTC). BCTC will not meet their hiring target of 10 due to revamping of job competencies and training programs (they have three hires to date). The final two Generation positions are on hold due to impacts of the revamped BCTC training program and reorganization. Three positions in Engineering will not be filled due to a staffing strategy change.

For more information about Strategic Workforce planning at BC Hydro please see page 68.

POWEREX

Powerex's goal is strong financial performance and increasing returns for its shareholder. This goal is measured by the following two indicators.

Net Income (in Millions) ▲

	Actual	Target
03/04 YTD	$93	$81

Net Income is defined as total revenue less total expenses before transfers to the Rate Stabilization Account. The targets are based on current cost and revenue drivers and the impact that cost reduction and/or revenue enhancement initiatives will have on these drivers.

Powerex's net income was better than target, mainly due to healthy price spreads and good forward calls being realized in the current quarter.

Sales Volumes[1] ●

	Actual	Target
Q3 03/04 YTD	25,340 GW·h	25,704 GW·h

Sales Volumes is defined as gigawatt hours sold (both electricity and gas). Targets have been set based on supply and demand forecasts.

For the year to date, the Sales Volume measure was on target. The actual figure includes 2,085 gigawatt hours of gas sales, whereas no gas sales were planned.

4. LINES OF BUSINESS

GENERATION

Introduction

- The Generation Line of Business is responsible for the operation, maintenance and financial performance of BC Hydro's existing integrated electricity generation assets throughout British Columbia. This includes 42 dams, 79 units at 31 hydroelectric generation facilities and nine units at three thermal generation facilities.
- Generation optimizes the value of these assets by managing inflows, storage, thermal resources, maintenance and investments to maximize profitability over the long term, while at the same time balancing environmental and social issues.
- The primary focus for Generation is value creation. Commercial performance, which is a measure of actual revenue relative to possible revenue, is a key indicator of success. Generation's Commercial Performance target for fiscal 2004 is 99.50 per cent, an increase over the fiscal 2003 Actual of 99.43 per cent. Commercial Performance for the first nine months of this fiscal year was 99.64 per cent. For reference, a 0.1 per cent improvement in Commercial Performance equates to approximately $2.5 to $3.0 million additional gross revenue.
- In late April 2003 BC Hydro filed with the BCUC recommendations with respect to the Commission's inquiry into the legislative changes necessary to implement the provincial government's *Energy for our Future: A Plan for BC.* The Commission accepted BC Hydro's recommendations, which became the basis for the BCUC's recommendations to the Lieutenant Governor in Council to preserve the value of BC Hydro's existing, low-cost electricity generation for British Columbians.
- The Provincial Government has implemented the BCUC recommendations through the BC Hydro Public Power Legacy and Heritage Contract Act and Special Directions to BC Hydro and the British Columbia Utilities Commission:

1. Heritage Special Directive to BC Hydro (HC1) is issued under Section 35 of the Hydro and Power Authority Act and requires BC Hydro to pay a dividend to the Province.
2. Heritage Special Direction to the BCUC (HC2) establishes a heritage contract between BC Hydro's Generation line of business and BC Hydro's Distribution line of business, including obligations to supply power and to pay for that power.
3. Heritage Contract, which is an attachment to HC2, defines all BC Hydro's existing integrated generation assets as "heritage resources", including potential future Resource Smart investments (for example Mica 5 and 6 and Revelstoke 5 and 6).

System Operation

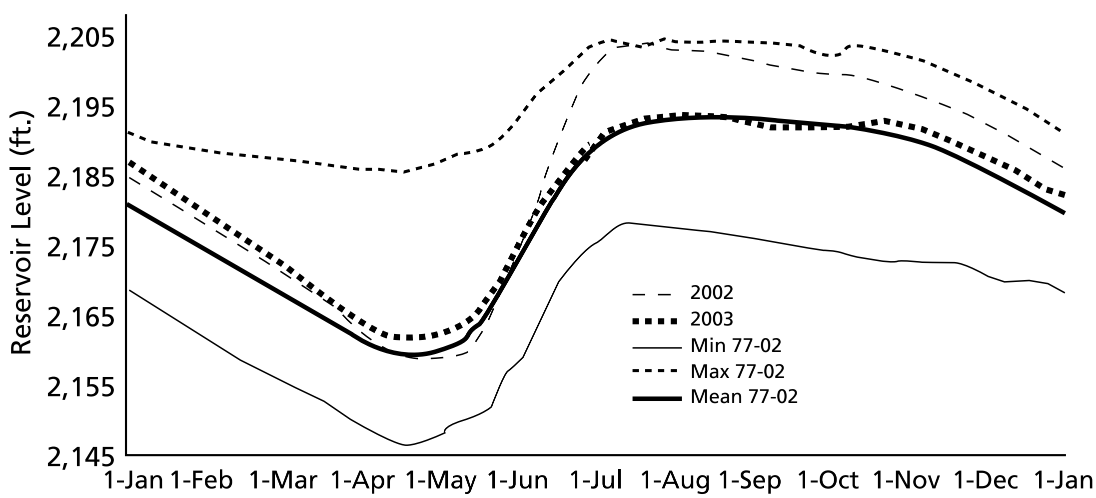
- BC Hydro monitors the levels at its hydroelectric reservoirs to ensure the most efficient use of stored water to meet domestic load and to maximize value creation through electricity trade. Reservoir levels at any time are a function of inflows (caused by snowmelt and/or rainfall runoff) and electricity demand (as water in the reservoirs is discharged through turbines to produce electricity).
- The snowpack accumulation through the fall and early winter has been below normal for the large interior basins in the Williston, Kinbasket and Kootenay regions and normal to slightly above normal for Vancouver Island and the Lower Mainland. The combined storage in BC Hydro's major reservoirs at December 31, 2003, was one per cent below average. This compares with the combined storage of BC Hydro's major reservoirs at December 31, 2002 of two per cent below average.

- System storage energy in BC Hydro's major reservoirs on December 31, 2003 was about 800 GW.h below the historical average for this time of year. With system energy below normal, net energy purchases will be required through to the end of the fiscal year.

Peace Region

- The Peace Region includes Generation's single largest facility, the 10-unit, 2,730 MW G.M. Shrum Generating Station and the four-unit, 700 MW Peace Canyon Generating Station.
- The Williston Reservoir reached a peak of 2,195 feet during August 2003. Since then, the reservoir has been drafting slowly and, as of December 31, 2003, was at 2,183 feet.
- The Williston early season snowpack accumulation has been below normal. Consequently, as of January 1, 2004, the February through September 2004 inflow forecast for Williston reservoir is 92 per cent of normal (with a standard error of plus or minus 13 per cent).
- Williston Reservoir is projected to draft to a low of about 2,153 feet (December projection) by the end of April 2004.
- In October 2003 a winding fault occurred on G.M. Shrum Unit 7, destroying the winding and causing damage to the stator core. Repairs are in progress and the unit is expected to be returned to service at the end of May 2004.
- During fiscal 2004, capital investment of $40.0 million was planned for the Peace River Area.
- Work to refurbish G.M. Shrum Generating Station Unit 6 was completed on schedule. As part of this work, the turbine was replaced under BC Hydro's Resource Smart program, resulting in an increase of 81 GW.h of energy at a cost of $10 million. A similar work program will be completed on Unit 8 in 2004.
- Concerns have been raised about the premature end of life of the generators at Peace Canyon Generating Station. BC Hydro sought and received advice from an Advisory Panel of international experts and is evaluating a decision to repair or replace the Peace Canyon generators.
- Other major capital work completed or in progress includes:
  - installation of two new exciters at G.M. Shrum
  - replacing a number of G.M. Shrum step-up transformers
  - upgrading Peace Canyon fire protection
  - upgrading Peace Canyon powerhouse crane

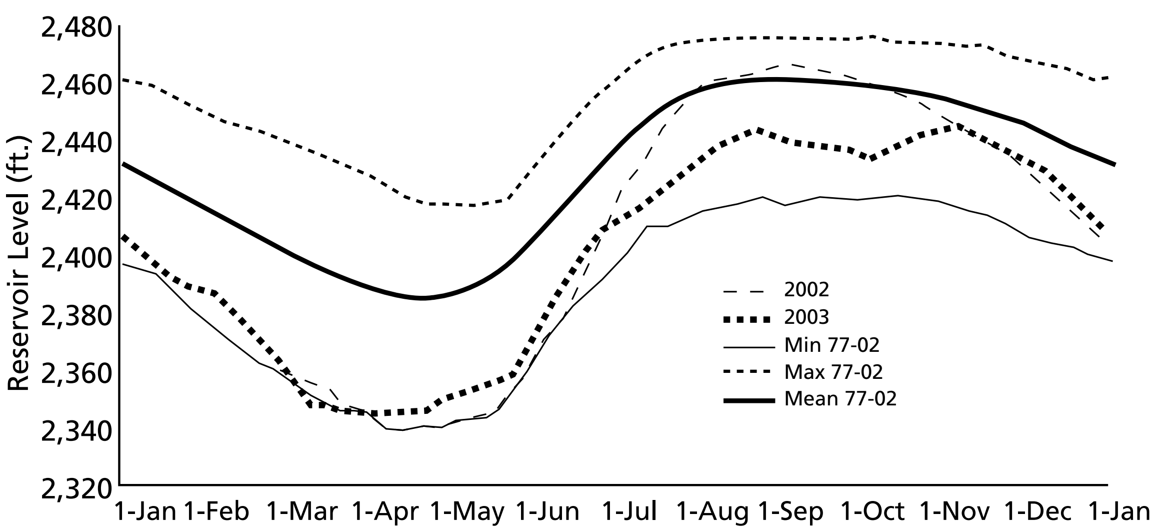
Williston Reservoir Levels



Columbia Region

- The Columbia Region has the largest installed capacity of the three Generation regions and includes the following facilities:
  - the four-unit, 1,860 MW Mica Generating Station
  - the four-unit, 2,000 MW Revelstoke Generating Station
  - the four-unit, 800 MW Seven Mile Generating Station
  - the four-unit, 580 MW Kootenay Canal Generating Station
  - Aberfeldie, Elko, Falls River, Shuswap, Spillimacheen, Walter Hardman, and Whatshan generating stations, totalling 13 units and 96 MW
- Kinbasket Reservoir reached a peak of 2,443 feet in late October 2003. Since then, the reservoir has been drafting slowly, and as of December 31, 2003, was at 2,409 feet.
- The early-season snowpack accumulation has been below normal. Consequently, as of January 1, 2004, the February through September 2004 inflow forecast for Kinbasket reservoir is 94 per cent of normal (with a standard error of plus or minus eight per cent). Forecasts for other basins in the region include Revelstoke at 89 per cent, Arrow Lakes at 99 per cent and Kootenay Lake at 97 per cent of normal.
- Kinbasket Reservoir is projected to draft to a low of about 2,354 feet (December projection) by the end of April 2004. This projected elevation is highly variable, however, and will be impacted by changes in system generation requirements and energy purchases.
- Arrow Reservoir reached a peak of 1,440 feet in early July 2003. Since then, the reservoir has been drafting, and as of December 31, 2003, was at 1,401 feet.
- An ongoing problem with the condition of the Mica Generating Station generators has progressed to the point where BC Hydro must address the issue. BC Hydro sought and received advice from an expert Advisory Panel and is evaluating a decision to replace the stators.
- In December 2003 a leak was discovered in the concrete liner of the Kootenay Canal Generating Station canal. Underwater inspection determined the canal was safe and the leak was temporarily sealed. Monitoring will continue until a permanent repair is designed and implemented.
- During fiscal 2004, capital investment of $59.4 million was planned for the Columbia Region.

Kinbasket Reservoir Levels

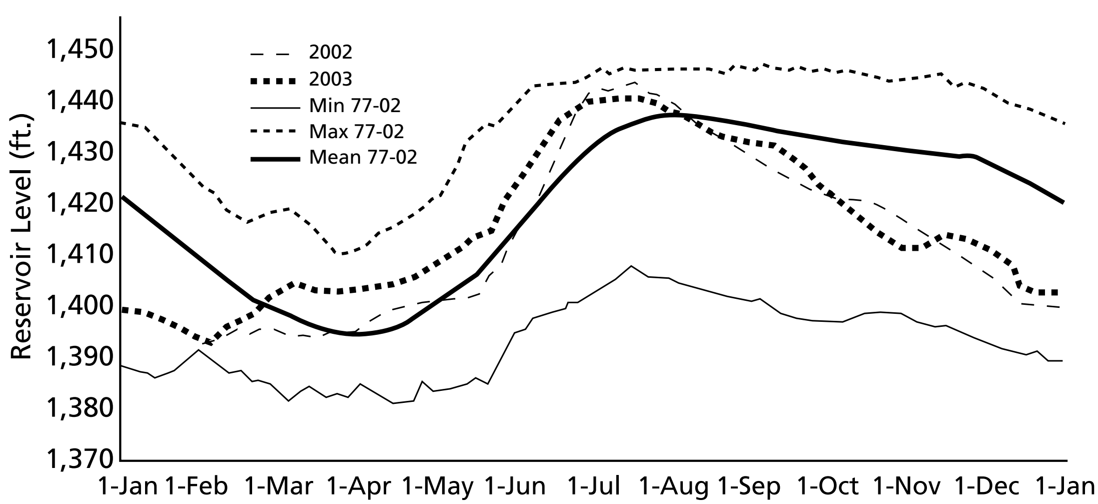


- The single largest capital project in the Columbia Region is the seismic upgrade of the Seven Mile dam. Steel anchors have all been installed, tested and fully tensioned in the concrete dam. Construction is continuing on schedule on the spillway tower structures. The seismic upgrade is scheduled to be completed by December 2006.
- BC Hydro received approval from the British Columbia Utilities Commission and the Provincial Environmental Assessment Office to decommission Coursier Dam, about 30 km south of Revelstoke, due to concerns about the safety of the dam. The decommissioning work has been completed, with revegetation work planned for 2004 and 2005.

Coastal Generation

- The Coastal Generation Region comprises 24 dams, 18 powerhouses and 36 generating units with an installed capacity of 1,528 MW located in 12 river basins throughout the province, plus three thermal generation facilities.
- The largest hydroelectric facilities include:
  - the eight-unit, 466 MW Bridge River complex
  - the two-unit, 167 MW Cheakamus Generating Station
  - the six-unit 132 MW John Hart Generating Station
  - the three-unit, 105 MW Ruskin Generating Station
  - the two-unit, 91 MW Stave Falls Generating Station
- Thermal generation facilities include:
  - the six-unit, 912 MW Burrard Generating Station
  - the two-unit, 46 MW Prince Rupert Generating Station
  - the single-unit 45 MW Fort Nelson Generating Station
- The snowpack accumulation in the early season has been near normal to slightly above normal for Vancouver Island, Lower Mainland and Bridge River basins. Consequently, as of January 1, 2004, the February through September 2004 inflow forecasts range from 112 per cent at Wahleach, 108 per cent at Campbell River and Comox, average at Bridge River and 94 per cent at Clowhom.
- Capital investment of $70.0 million is planned for the Coastal Region.
- Dam safety improvements at Elsie Dam will improve the dam's performance in major

Arrow Reservoir Levels



earthquakes. The work on the earthfill dam was completed in 2001, and during 2002 upgrades were made to the upstream portion of the low-level outlet structures in the dam. The remaining upgrades to the low-level outlet conduit and valves are in progress and scheduled for completion by 2005 at a total project cost of $17 million.

- The Coquitlam Dam requires upgrading to meet present earthquake standards. During 2002 various remediation options were investigated and the preferred option has been determined. The project costs will be about $40 million and remediation is expected to be complete by the end of 2006. In the interim, the reservoir has been restricted to protect public safety.
- Other major projects in progress include:
  - refurbishing Cheakamus Units 1 and 2, including replacing the existing runners
  - replacing transformers at Bridge River, John Hart and Strathcona generating stations
  - safety improvements at La Joie, Blind Slough and Ruskin dams
  - removal and management of asbestos at Burrard
  - modifying one unit at Burrard to enable synchronous condenser operation, including control upgrade
  - enhancing start-up capability of Burrard units
- As announced in the British Columbia Government's Energy Plan (Energy for our Future: A Plan for BC), released in November 2002, an MLA Task Force has been established to determine the future of BC Hydro's gas-fired Burrard Generating Station. Burrard is important to the BC Hydro system by providing capacity and supporting transmission transfer capability. Options include continued operation of the existing plant; phasing out the plant; using Burrard for capacity only; or repowering the plant, to take advantage of the latest technology in terms of efficiency and emissions.
- Non region-specific capital expenditures of $18.1 million are planned for fiscal 2004.

Financial Highlights

Interim Report — Generation — nine months ended December 31, 2003

In millions	2003 actual	2002 actual	% change
External revenues	12.5	41.8	–70%
Inter-segment revenues	1060.6	943.7	12%
Net income (loss)	284.2	140.1	103%
Capital expenditures			
Sustaining	80.7	82.4	–2%
Growth	22.1	110.4	–80%
	102.3	192.8	–47%

Highlights Notes:

- Net Income for the nine months ended December 31, 2003, was $284 million, compared with Plan of $134 million. This increase above Plan was primarily due to higher-than-Plan sales to Distribution (+762 GW.h; +$21 million); higher-than-forecast revenue from Powerex (+$15 million); lower-than-Plan energy purchases and lower electricity purchase prices (–373 GW.h; –$75 million; average purchase price $47.87 per MW.h vs. Plan $61.96 per MW.h); and lower-than-Plan finance charges due to lower interest rates and improvement in the US$ exchange rate (+$48 million.). This increase was partially offset by higher water rentals (–$10 million) and higher OMA costs (–$5 million), due to higher-than-Plan maintenance costs.
- Capital spending (excluding VIGP and GSX) during the nine months ended December 31, 2003, was $103 million or 30 per cent below Plan of $146 million, primarily due to reduced expenditures on Dam Safety Projects.

PERFORMANCE MEASURES — GENERATION

Generation's four key goals are:

Strong financial performance — through targeting first-quartile (top 25 per cent) results.

Quality service — through ensuring that Generation facilities are able to meet contractual obligations to Distribution and are available to maximize market opportunities.

Good environmental and social performance — through continuing to manage environmental and social issues that are a priority to Generation.

Skilled workforce, safe workplace — by providing employees with the means to be successful and ensuring safety.

The following indicators measure these goals. In addition to these indicators, Generation tracks a number of measures that cascade from BC Hydro's overall measures.

Net Income (in Millions) ▲

	Actual	Target
YTD 03/04	$284.3	$133.3

Net Income is defined as total revenue less total expenses before transfers to the Rate Stabilization Account. The targets are based on current cost and revenue drivers and the impact that cost reduction and/or revenue enhancement initiatives will have on these drivers.

Net Income for the nine months ended December 31, 2003, was better than target, primarily as a result of higher sales, reduced electricity purchases, lower electricity purchase prices and lower finance charges.

Cost per Megawatt Hour Generated ▲

	Actual	Target
Q3 03/04	$22.63	$26.55

Cost per MW Hour Generated is defined as all Generation costs divided by the volume of energy generated under average water conditions. Currently, all major hydroelectric generating units place in the first and second quartiles for cost efficiency (Haddon Jackson).

At the end of nine months, the Cost per Megawatt Hour Generated measure was better than target, due to lower energy costs and reduced finance charges.

Commercial Performance ▲

	Actual	Target
Q3 03/04	99.6%	99.5%

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. Targets have been set based on historical performance (including analysis of planned outages) and assessment of reasonable improvement given investment in assets.

At the end of nine months, Commercial Performance was better than target.

Resource Smart Energy Gains Put Into Service ▲

	Actual	Target
Q3 03/04	460 GW·h	411 GW·h

Resource Smart Energy Gains put into Service is defined as the projected long-term average incremental energy gains for existing Generation facilities that are put into service during the year.

The Resource Smart target for fiscal 2003/2004 is 411 GW.h. Generation has exceeded this target during the first nine months of the fiscal year.

Introduction

- Distribution Line of Business serves 1.6 million customers and another 6,000 customers in non-integrated areas within B.C. It manages 56,000 km of overhead, underground and submarine distribution lines, 876,000 poles and 344,000 transformers in order to provide customers with safe, dependable and reliable energy, as well as extension and connection services. Consistent with the provincial government's new Energy Plan, Distribution's mandate is to:
  - Uphold its obligation to serve BC Hydro's domestic ratepayers (Distribution is responsible for defining the customer experience and to work with other BC Hydro lines of business to ensure safe, high-quality service).
- Administer the Heritage Contract to preserve the benefits of BC Hydro's existing generation and electricity trade for Distribution customers.
- Develop new rate structures that will:
  - Enable large electricity customers to choose a supplier other than BC Hydro.
  - Provide better price signals for conservation and efficiency.
  - Maintain high reliability and energy security.

ELECTRICITY LOAD

Short-Term Forecast

- The forecast of firm sales including Power Smart for the current fiscal year is 49,180 GW.h. Compared with the March 2003 planned forecast, the variance is +98 GW.h or 0.2 per cent above planned sales. The variance in the current forecast to the planned forecast by rate class is:

Current vs. Planned Forecast

Rate Class	October 2003* Forecast (GW·h)	March 2003 Forecast (GW·h)	Variance (GW·h)
Residential	15,638	15,456	+182
General	16,944	17,030	–86
Transmission	14,801	14,813	–12
Other	366	366	0
Other Utilities	1,431	1,417	+14
Total	49,180	49,082	+98

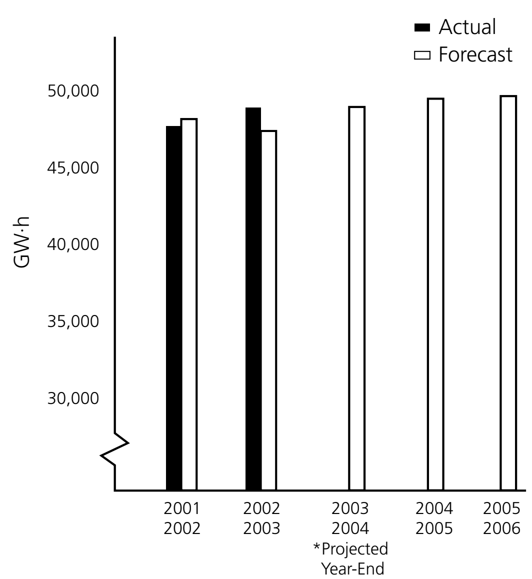
** October reflects the month in which forecast was produced.*

Variance Explanation

1. Drivers:

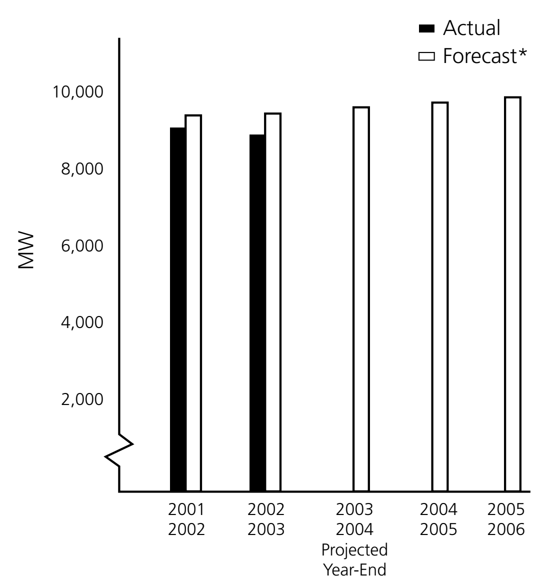
- Compared with BC Hydro's Second Quarterly Report, the forecast is unchanged as the forecast and actual sales are tracking close to plan.

BC HYDRO SYSTEM–BILLED SALES



* Projected Year-end is based on the September 2003 forecast.

BC HYDRO SYSTEM–PEAK DEMAND



* Forecast BC Hydro System peak is based on a design daily average temperature of –6.8ºC.

- The variance in the current forecast compared with the March plan reflects changes in the economy that impact the drivers of the energy forecast. For example, a slower economic recovery, due to events such as the impact of SARS on tourism sales, led to lowering the starting point for this year's forecast of sales to the General Sector. Actual sales in fiscal 2002/2003 to the General sector were 12 GW.h below the March 2003 planned sales for fiscal 2002/2003.
- Other events, such as the impacts of a 27-per-cent duty on softwood lumber on B.C.'s lumber industry, have led to a downward revision in the industrial sales forecast relative to the forecast of planned sales. Transmission sales in fiscal 2002/2003 were 20 GW.h below the March 2003 planned sales, so the starting point for the current forecast is lower than anticipated.
- The positive variance in the residential sales forecast compared with plan sales reflects a continued strong growth in housing starts. In addition, use of electricity per residential customer is also expected to be higher this year compared with last year due to a higher saturation of electronic products. The higher use rate also contributed to the upward revision in the residential sales forecast.

2. Energy Sales BC Hydro System:

- Current sales, on a fiscal year-to-date basis, continue to track planned sales. Total sales are +409 GW.h or 1.3 per cent higher compared with plan sales over the first eight months of the fiscal year. Residential sales continue to have the highest variance of +344 GW.h or 3.9 per cent higher. The variance is largely due to the fact that the current weather-adjusted sales per account is greater than the March plan. In order to maintain the gap in year-end variance of the current forecast of March 2003 planned residential sales, it is expected that the current residential sales variance for the remainder of the year would need to decrease by about 162 GW.h. The variance in current sales to planned sales over the first eight months of this fiscal year is:

Current vs. Planned Sales

Rate Class	**Current Sales (GW·h)**	**Planned Sales (GW·h)**	**Total (GW·h)**
Residential	9,100	8,757	+344
General	11,170	11,129	+41
Transmission	10,170	10,103	+67
Other	240	246	–6
Other Utilities	730	766	–37
Total	31,410	31,001	+409

- Total sales compared with last year over the first eight months of the fiscal year are +430 GW.h or 1.4 per cent higher. The table below shows a comparison of sales over the first eight months of this fiscal year with last year.

Current vs. Previous Sales

Rate Class	Current Sales (GW·h)	Previous Year (GW·h)	Total (GW·h)
Residential	9,100	9,028	+72
General	11,170	10,995	+176
Transmission	10,170	9,976	+194
Other	240	244	–4
Other Utilities	730	737	–8
Total	31,410	30,980	+430

Peak Demand – Forecast

- BC Hydro is a winter-peaking utility driven by residential electric spacing heating. Last year BC Hydro reached its highest one-hour peak demand (Integrated System Peak) of 8,816 MW at a daily average temperature of +5.3°C on December 18, 2002. During this past December, the Domestic System reached a one-hour peak of 8,883 MW at a daily average temperature of –0.9°C on December 30, 2003. Although this quarter's report is information up to the end of December 31, 2003, it is worth noting that BC Hydro recorded its highest domestic peak ever on Monday, January 5, 2004 at 9,619 MW at a daily average temperature of –7.1°C.
- BC Hydro's Total Integrated System peak forecast including Power Smart is 9,620 MW. Compared with the preliminary peak forecast in the Second Quarter Report of 9,543 MW, the forecast was increased by 77 MW due to additional information on transmission peak requirements. Compared with last year's peak forecast of 9,663 MW, this year's peak forecast is –43 MW or 0.5 per cent below. Changes in the peak forecast reflect a decline in some of the drivers such as employment and industrial outlook, as well as changes in the methodology of determining historic weather-adjusted peaks.
- The forecast is based on a design day temperature of –6.8°C, which is currently under review pursuant to the BCUC's VIGP Decision.

Vancouver Island (VI)

Short-Term Forecast

- This fiscal sales forecast including Power Smart for the Island is 10,560 GW.h, compared with the March planned sales of 10,510 GW.h. A comparison by rate class of the current forecast and the March forecast is:

Current vs. Planned Forecast

Rate Class	October 2003* Forecast (GW·h)	March 2003 Forecast (GW·h)	Variance (GW·h)
Residential	4,091	4,057	+34
General	2,632	2,671	–39
Transmission	3,789	3,732	+57
Other	48	50	–2
Total	10,560	10,510	+50

** October reflects the month in which forecast was produced.*

Variance Explanation

1. Drivers

- Compared with BC Hydro's Second Quarter Report, the current VI forecast remains unchanged as the forecast and current sales are tracking close to plan.
- Compared with the March forecast, the forecast of sales to the General rate class was revised below the planned sales, as it is expected that the softwood tariffs will continue to impact sales to some of the higher-cost mills on VI. As of the end of November, billed sales to VI's General Over 35 kW Wood Sector and Paper and Allied Products Sector are both 16 per cent below last year's sales on a fiscal year-to-date basis.

2. Energy Sales VI

- On a fiscal year-to-date basis, VI sales are tracking close to plan, as total sales are +75 GW.h or 1.2 per cent higher than March planned sales. Current sales may continue to exceed planned sales because the current electricity use per residential customer may continue to exceed the use per customer as forecast in the March 2003 plan. The variance of actual sales to March planned sales over the first eight months of this fiscal is:

Current vs. Planned Sales

Rate Class	Current Sales (GW·h)	Planned Sales (GW·h)	Total (GW·h)
Residential	2,233	2,207	+26
General	1,703	1,685	+18
Transmission	2,587	2,554	+34
Other	29	31	–2
Total	6,552	6,476	+75

- Total sales on VI have increased by +45 GW.h or 0.7 per cent this year compared with last year over the first eight months of this fiscal. By rate class, this growth is:

Current vs. Previous Sales

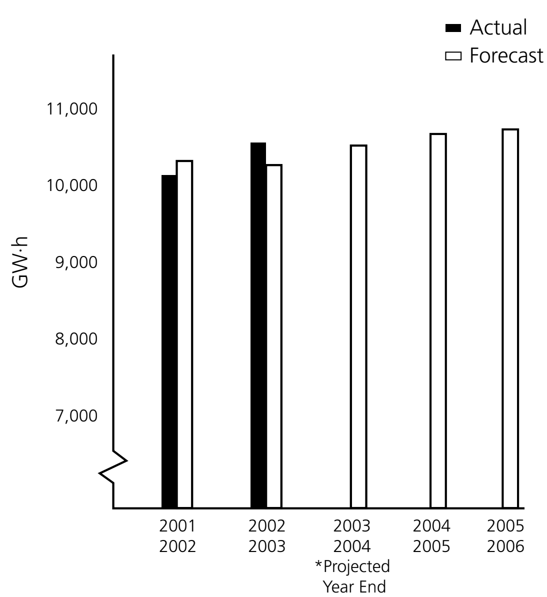
Rate Class	Current Sales (GW·h)	Previous Year (GW·h)	Total (GW·h)
Residential	2,233	2,259	–26
General	1,703	1,687	+15
Transmission	2,587	2,530	+57
Other	29	31	–2
Total	6,552	6,507	+45

- The growth in VI Transmission sales may be attributed to additional Transmission sales to the Pulp and Paper Sector, which are +61 GW.h or 2.6 per cent above sales last year over the first eight months. A key factor, which may have led to higher sales in the pulp and paper sector, is pulp prices. Compared with last November, average prices of Northern Bleached Softwood Kraft have increased by approximately 19 per cent. In addition, average natural gas market prices are above last year's prices over the first few months of this year's heating season. As such, higher gas prices may also impact on transmission sales to customers with self-generation.

Peak Demand – Forecast

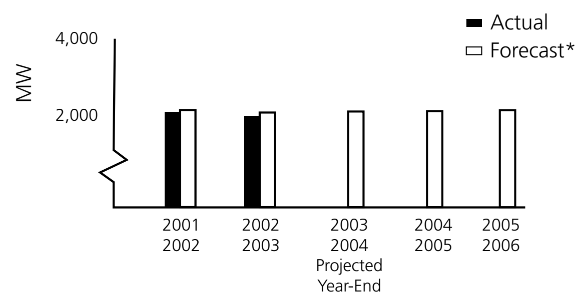
- VI's system peak reached a one-hour peak of 1,999 MW on February 25, 2003, at a daily average temperature of +2.1°C at the Victoria airport. The peak is driven by the large presence of electric heating on the Island and, as a result, it increases as temperatures get colder. Although this quarter's report is information up to the end of December 31, 2003, it is worth noting that BC Hydro recorded its highest peak ever on Vancouver Island on Sunday, January 4, 2004, which was 2,193 MW at a daily average temperature of –4.7°C.
- The forecast is prepared based on using a design temperature of –4.4°C. The design temperature for VI is under review.
- The peak forecast for VI including Power Smart is 2,136 MW, which is 17 MW below the preliminary forecast as reported in the Second Quarter Report. The forecast was revised due to changes in the estimates of the VI transmission peak. Compared with last year's forecast, the peak forecast this year is 28 MW lower. Part of the decline in the peak can be attributed to the expected impacts of softwood tariffs on the distribution peak load requirements for VI.

VANCOUVER ISLAND–BILLED SALES



* Projected Year-end is based on the September 2003 forecast.

VANCOUVER ISLAND–PEAK DEMAND



* Forecast VI peak is based on a design daily average temperature of –4.4°C.

ELECTRICITY & NATURAL GAS PRICES

- BC Hydro tracks market information that forms the basis for its future price forecasts for both electricity and natural gas. Because BC Hydro is part of a larger market extending, in the case of electricity, through the western and southwestern United States and, in the case of natural gas, throughout North America, BC Hydro is subject to market forces beyond its borders that influence prices.

Forward Market Information

- In the short term, BC Hydro tracks “forward prices,” which are market price quotes on transactions for delivery at a specified time and delivery point. For electricity, the nearest commonly traded delivery point is Mid-Columbia, and in the case of natural gas it is Sumas.
- Forward market quotes are readily available for a period of up to three years for electricity and for three to five years for natural gas. Forward prices for both electricity and natural gas are usually volatile, but they provide an important near-term reference point since they reflect all the information currently available to market participants.

Longer-Term Market Fundamentals

- The longer-term forecast is based on representations of the supply and demand for electricity and of cost drivers expected to prevail.
- Key factors in the long-term electricity price forecasts are:
  - **Supply** — the expected stock and availability of generating units (especially new units); the onstream timing of new reserves versus production decline rates
  - **Generation Costs** — the expected level of fuel prices (especially natural gas) and other costs of operating generating units
  - **Demand** — the level of demand as driven by forecasts of economic activity, technology and expected conservation
  - **Regulatory/Market** — the expected state of the regulatory or market environment
- Key drivers for long-run natural gas price forecasts are similar to electricity prices as they relate to supply and production costs:
  - **Supply** — the onstream timing of new reserves versus decline rates
  - **Production Costs** — the costs of exploration and drilling, and the pace of technological advancements that serve to reduce costs
- BC Hydro acquires the forecast output and market analysis of a number of third-party forecasts to supplement its long-term forecasting activities.

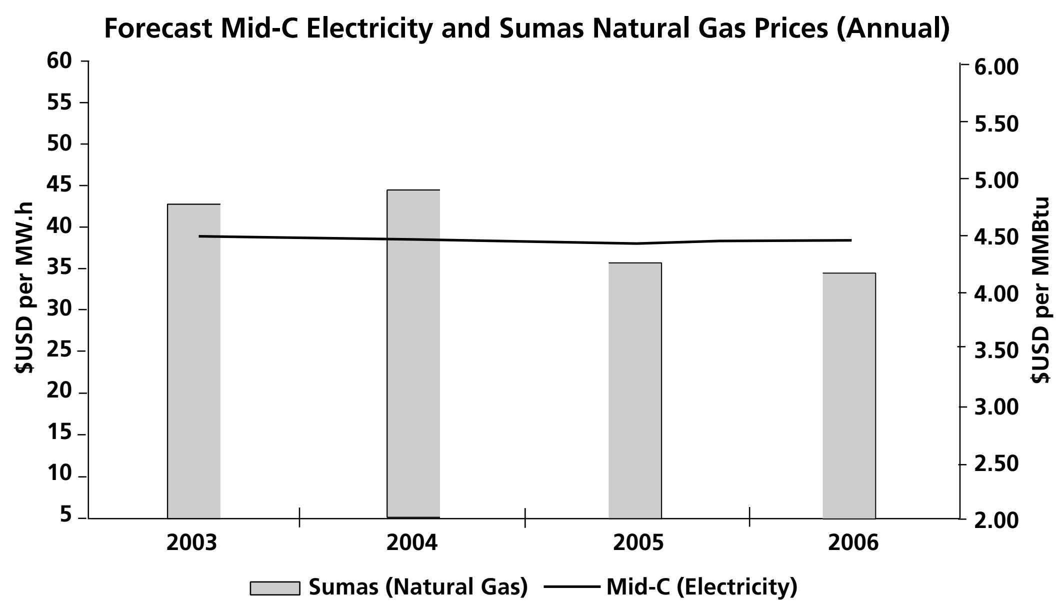
Market History

The last quarter can be characterized as follows:

- Natural gas and electricity prices were volatile and relatively high.
- Natural gas storage inventories have recovered from the lows reached at the beginning of 2003. Supplies are near the five-year average and are anticipated to remain adequate during the heating season. This will exert downward pressure on prices provided the winter is near normal.
- Fall weather was near normal, followed by a relative cold early winter. This has led to rising prices toward the end of the third quarter.
- Wetter conditions in the West increased hydroelectric generation capacity, which has tended to moderate electricity prices despite high gas prices.
- Renewed expansion of the U.S. economy has led to increased demand for gas and electricity, especially in manufacturing and other industrial areas.

Market Outlook

- Natural gas forwards are currently relatively high, and crude oil prices have been rising. While replenished inventories of gas in storage exerts downward pressure on prices, there is growing concern that production will have difficulty keeping up with demand. This concern has increased now that the economy has begun to grow rapidly again. The medium-term gas forecast shows prices declining slightly. However, there is a risk that a tighter supply/demand balance may lead to increases in gas prices.
- Electricity forwards show a slight declining trend, with seasonal peaks in summer and winter. Recently built generation capacity is expected to continue to exert downward pressure on electricity prices for several years. The improved hydro outlook will also tend to moderate prices. But renewed economic growth and high gas prices may move prices upward.
- In the medium term, most observers forecast robust economic growth. Electricity price expectations are based on a supply/demand balance tightening with economic growth. Long-term prices of both electricity and gas are expected to exhibit considerable volatility and to be vulnerable to fluctuations in weather that impact supply and demand.



RESOURCE ACQUISITION

Call for Tenders – Vancouver Island

- BC Hydro issued its Call for Tenders (CFT) for capacity and associated energy supply on Vancouver Island on October 31, 2003. This information, along with the preliminary Electricity Purchase Agreement and the Independent Reviewer's Initial Report (PriceWaterhouseCoopers) was filed with the BC Utilities Commission.
- Private sector developers interested in participating in the Call for Tenders were requested to register their intent by November 14, 2003. Twenty-three developers registered to participate in the CFT process; and of those, 14 chose the VIGP Election, indicating interest in acquiring the VIGP development assets and the proposed Duke Point site.
- To date, the following events in the process have occurred:
  - A Pre-Qualification Workshop was held November 21, 2003, and BC Hydro responded to over 100 workshop questions via website posting on November 26, 2003.
  - On December 1, 2003, registered bidders submitted over 250 comments to BC Hydro regarding the CFT and the Preliminary Form Agreements. On December 15, BC Hydro posted responses to all bidders' comments and indicated that certain revisions would be made to the CFT and associated agreements (e.g., allowing split bids).
- A revised CFT, Preliminary Form EPA and Preliminary Form VIGP Transfer Agreement, together with Bidder Reply/Comments forms, are to be filed with the BCUC in early January. In response, the BCUC is to provide approval of the revised CFT, including amended Preliminary Form Agreements, by the end of the month.
- On January 23, 2004, the BCUC provided a response on the Vancouver Island CFT process. BC Hydro is reviewing the BCUC response.

Green Independent Power Producers (IPPs)

- Green Power IPPs are part of BC Hydro's energy acquisition program, which seeks to acquire a total of 10,000 GW.h annually by 2012 to meet load growth. Green Power IPPs have been targeted as part of this volume through a series of calls. BC Hydro has 381.6 GW.h/year of green energy online. The 2002 Green Power Generation Call for Tender recently concluded with16 contracts signed representing 1,764 GW.h, 964 GW.h above the acquisition target, which was 800 GW.h. Next steps include filing of the contracts with the BC Utilities Commission, and working with developers to advance their projects.

Customer-Based Generation

- Customer-Based Generation (CBG) is also a component of BC Hydro's energy acquisition program and is proceeding pursuant to the same standardized call process as for Green Energy. The 2002 CBG Call for Tenders resulted in five contracts totalling 500 GW.h. Of those, three remain, representing 341.8 GW.h.

Green Power Certificates

- BC Hydro offers a Green Power Certificate (GPC) product to support customer demand for choice and green product offerings to domestic and wholesale trade customers. The pilot program is under assessment to extend it from a pilot to a permanent offering to customers.

Power Smart

- Power Smart continues implementing its comprehensive 10-year plan to reach an annual target of a further 3,500 GW.h/yr. in new energy savings, or enough to supply about 350,000 additional homes in British Columbia.
- For the third quarter of this fiscal year, total cumulative run-rate energy achieved was 586 GW.h/yr., placing Power Smart ahead of the first-quarter target of 575 GW.h/yr. and on track to reach this year's cumulative target of 810 GW.h/yr. The above figures include a discount for free riders and free drivers, and measurement and verification for business sector programs. Free riders refers to those who participate in a program but would have done so without an incentive; free drivers refers to those who do not participate in a program (e.g., use a coupon) but are influenced by it and change their behaviour because of it; business sector programs are discounted by five per cent to allow for energy savings that may be lower than initial estimates when actually measured.
- For business customers:
  - The City of Kamloops approved a program with BC Hydro to convert as many as 72 intersections from incandescent lights to energy-efficient light-emitting diode (LED) traffic lights. This upgrade is expected to save Kamloops taxpayers almost $42,424 per year from energy savings alone. The city also estimates that its light maintenance budget will be reduced by about $20,000 a year. LED traffic lights consume 90 per cent less energy than standard incandescent lights, last six to 10 times longer and provide increased safety for motorists and pedestrians.
  - BC Hydro announced a 15-year agreement with Canadian Forest Products Ltd. (Canfor) on October 31 to upgrade its Prince George Pulp and Paper mill to provide all of the electricity needs at that mill and its Intercontinental Pulp mill. BC Hydro will contribute $49 million to Canfor's $81 million project to install a 48-megawatt turbo generator project at the mill site, saving BC Hydro enough electricity to serve 39,000 homes. Canfor's project will generate 390 gigawatt hours (GW.h). BC Hydro is contributing about 1.5 cents/kilowatt hour (kW.h) to the cost, which is significantly lower than BC Hydro's cost of 5.5 cents/kW.h for acquiring new generation. Canfor will rely less on BC Hydro for its power needs and BC Hydro will have more energy to serve its other customers. This is the second such agreement BC Hydro has reached with large industrial customers, and as many as 10 other load displacement agreements are being contemplated. Canfor is one of BC Hydro's largest industrial customers. The company has three pulp mills in the Prince George area: Prince George Pulp and Paper, Intercontinental and Northwood mills. Under the agreement, Canfor will install a turbo-generator, wood residue handling and conditioning system, modify its pulp mill boilers and processes to optimize steam produced for electricity, and upgrade the mill's electrical system. The project is scheduled for completion by February 2005.
- Power Smart held a successful Pulp and Paper Energy Efficiency Workshop on November 20 and 21, designed specifically for and very relevant to this key B.C. market sector. The Pulp and Paper sector uses over 50 per cent of the electrical energy consumed by BC Hydro's industrial customers. It is estimated that approximately 75 per cent of the likely achievable savings in the next 10 years will come from this sector. At the workshop a slate of leading technical experts addressed such topics as opportunities for self-generation, new energy-efficient technologies, techniques for

system optimization and the impact of energy on pulp and paper product competitiveness. Attendees came from across the province and represented all of BC Hydro's major customers in this sector.

  - The Power Smart Product Incentive Program was introduced to help small to mid-sized business customers upgrade their existing products with energy-efficient technologies that will help them reduce their energy costs and save money. The program provides incentives of up to $30 per item for the installation of eligible energy-efficient products. Each eligible product has a set incentive amount, which allows organizations to focus on the specific technologies they want to upgrade or replace. A wide range of energy-efficient lighting products are eligible for incentives under the program, including T8 lighting, compact fluorescent lighting, LED exit signs, pulse-start metal halide lighting and high-pressure sodium lighting. Vending machine sensors, which reduce energy use when the machines are not being used, are also eligible. The program will run for three years and is targeted to save 50 GW.h of electricity.

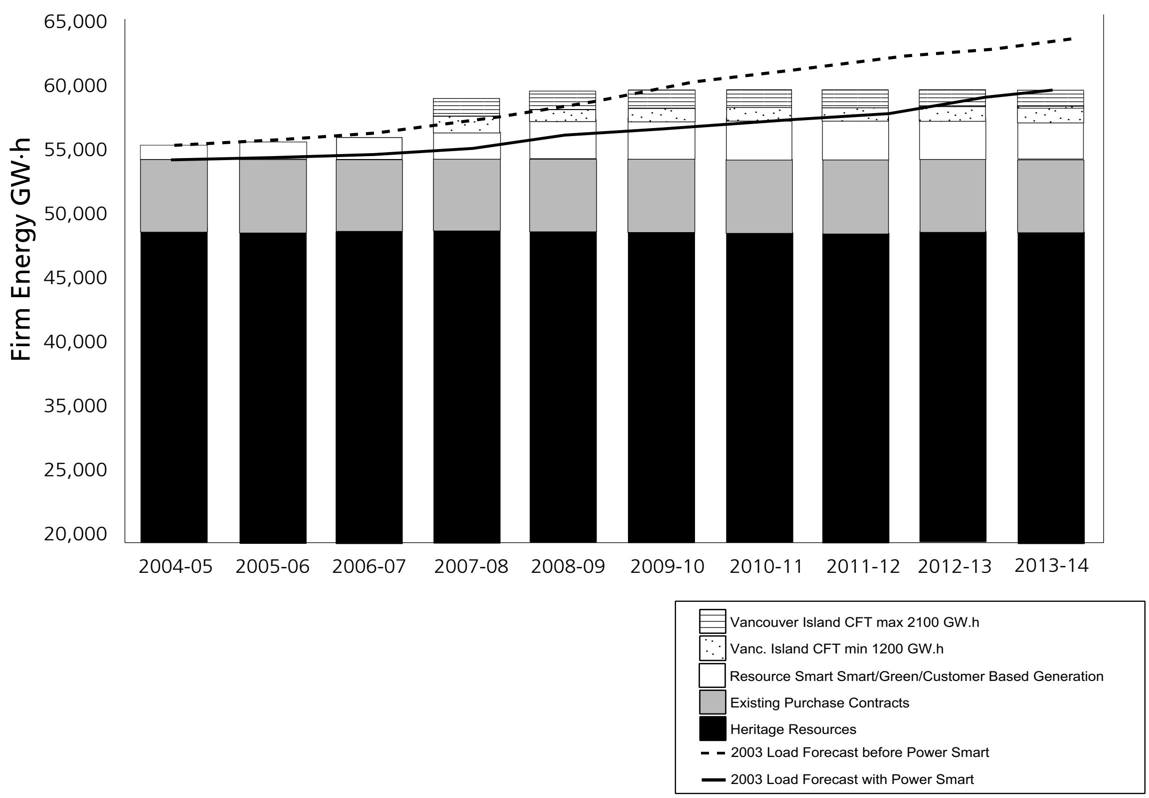
- For residential customers:
  - BC Hydro launched a campaign in September to educate customers across B.C. about the benefits of energy conservation and encourage Power Smart program participation, including energy-efficient compact fluorescent light bulbs (CFLs). As part of the promotion, BC Hydro mailed more than 700,000 Lower Mainland customers a direct mail voucher for two free CFLs, which they can then redeem at a Power Smart booth at a local retail location. Only a week after the launch, over 50,000 customers had participated, and, as of December 31, 2003, over 300,000 customers had redeemed their voucher at a retailer.
  - With a goal to recycle 25,000 fridges to save 23 GW.h hours of energy annually by August 2004, BC Hydro relaunched its Power Smart Refrigerator Buy-Back Program across the province in September 2003. BC Hydro will pay customers $30 and pick up their second refrigerator and dispose of it free of charge in an environmentally friendly way. Refrigerators are one of the largest energy users in the home, representing up to 20 per cent of an energy bill. At December 31, 2003, 13,900 customers had already had their fridges picked up.
  - BC Hydro introduced the Power Smart New Home program in November to encourage developers to install energy-efficient technologies, or Power Smart Packages, in new home developments. These installations help new-home buyers lower their energy consumption and cost of running their new homes, while retaining value and increasing home comfort. Power Smart also initiated a new Renovation Rebate program to offer qualified residents with electric heat financial rebates for conducting specific energy-efficient home improvements to windows and insulation.

- For the community:
  - BC Hydro contributed $10,000 to support the interior's largest seasonal lighting exhibit at the BC Wildlife Park. The display featured over 350,000 lights, including 350 wildlife light sculptures. For the second year in a row the BC Hydro Power Smart Wildlights event will feature seasonal LED light strings. These energy-efficient holiday lights use up to 90 per cent less electricity than incandescent seasonal light strings and last up to seven times longer. More than 30,000 people were expected to visit the park to enjoy the spectacular lighting displays.

LOAD RESOURCE OUTLOOK

- BC Hydro plans and operates its system to ensure that it meets the electricity needs of customers, both now and for the future. The goal is to ensure there is enough electricity supply to meet the "load" (or electricity demand) by using a range of existing and future resources. These resources – and their relative contributions to the BC Hydro system – are shown in the following charts. These charts reflect the capability of the resources in BC Hydro's supply portfolio rather than expected generation. In BC Hydro's annual planning cycle these charts are typically updated during the second half of the fiscal year.
- The reliable supply of energy and capacity from the heritage resources, based on the Heritage Contract, is reflected in the following resource outlooks.
- BC Hydro has issued a Call for Tenders for up to 300 MW (minimum 150 MW) to address Vancouver Island supply required by 2007.
- The Burrard MLA Review is underway, which may affect the future contribution of that generating plant.

System Firm Energy Supply–Demand Outlook



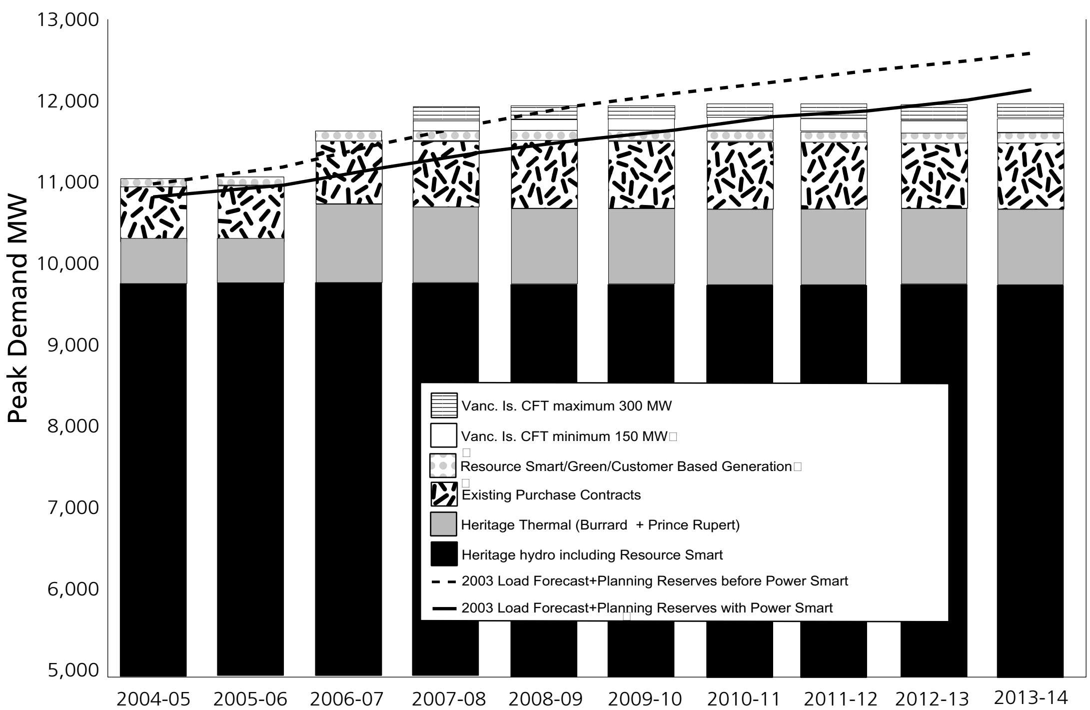
System Firm Energy Supply — Demand Outlook

- The System Firm Energy Supply-Demand Outlook chart compares annual energy demand, with and without the impact of Power Smart, and the energy capability of existing and contracted new supply.

Assumptions

- 2003 Load Forecast shown with and without Power Smart.
- Heritage Resources — BC Hydro has proposed that the Heritage Contract provide for a maximum energy supply obligation, subject to force majeure, of 49,000 GW.h per year (the Heritage Energy). The heritage resources include the BC Hydro hydroelectric resources and BC Hydro thermal resources: Burrard, Prince Rupert and Fort Nelson. The heritage energy of 48,845 GW.h (after adjustment for the non-integrated Fort Nelson G.S.), is currently supported by underlying firm energy from hydroelectric resources of 43,000 GW.h, with the balance depending on market and supply conditions, from a combination of market, thermal and non-firm hydro resources.
- Existing Purchase Contracts include all IPP contracts that occur pre-2000, as well as the Alcan and Arrow Lakes Hydro contracts.
- Resource Smart/Green/Customer-Based Generation includes the expected contribution from existing and committed Resource Smart, Green and Customer-Based Generation Calls.
- The planned Vancouver Island Call for Tenders is expected to contribute between 1,200 and 2,100 GW.h per year of new energy supply.
- Allowance for Market Purchases — In the planning for new resources, BC Hydro has relied on 2,500 GW.h/yr. from the wholesale market. This number is currently under review.

System Dependable Capacity Supply–Demand Outlook



System Dependable Capacity Supply — Demand Outlook

- The System Dependable Capacity Supply-Demand Outlook chart compares the forecast peak electricity demand (peak winter usage) with and without the impact of Power Smart – plus required capacity reserves – against the dependable capacity of existing and planned facilities.

Assumptions

- 2003 Load Forecast plus planning reserves shown with and without Power Smart.
- Capacity and Planning Reserves — BC Hydro is obligated to maintain operating reserves set by the Western Electricity Co-ordinating Council (WECC). For the BC Hydro system, this is about seven to eight per cent of load. In addition, the WECC recommends that each utility carry sufficient capacity reserves to allow it to withstand the temporary outages of generating units. Based on loss-of-load analysis for the BC Hydro system, this criterion can be met by maintaining capacity reserves of approximately 14 per cent of dependable capacity supply. Since BC Hydro is interconnected with other systems, up to 400 MW of capacity from imports is assumed available.
- The contribution of the hydroelectric and thermal heritage resources is based on their dependable capacity. Currently, BC Hydro will rely on Burrard G.S. to support dependable capacity based on three units for each of the next two years (2004/2005 and 2005/2006), and is reviewing requirements to support six units for the balance of the period.
- Resource Smart/Green/Customer-Based Generation includes the expected contribution from existing and committed Resource Smart, Green and Customer-Based Generation Calls.
- Existing Purchase Contracts includes all IPP projects (pre-2000) with which BC Hydro has an energy purchase agreement. The contribution of the Alcan contract and the Arrow Lake Hydro project are also included.
- The planned Vancouver Island Call for Tenders is expected to contribute between 150 and 300 MW of new dependable capacity.

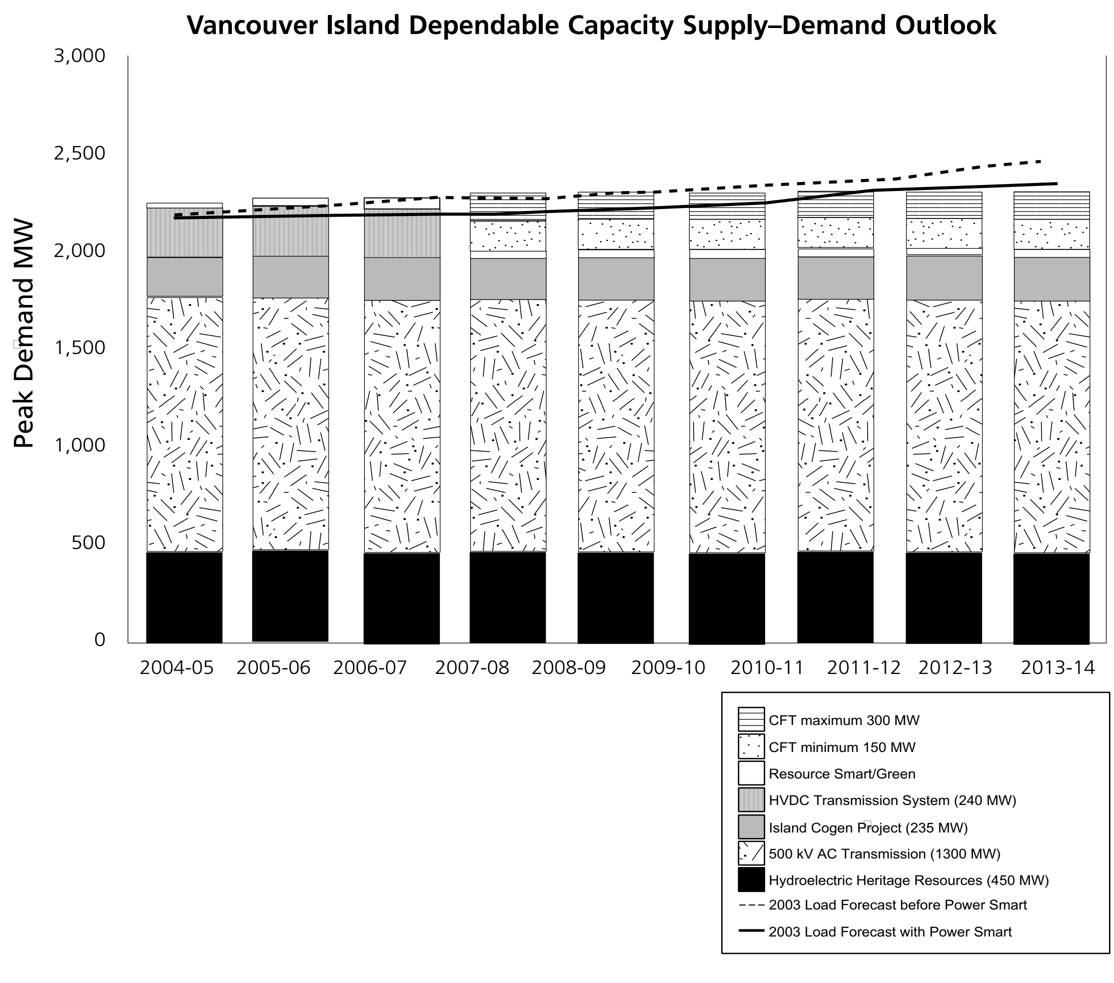
Vancouver Island Dependable Capacity Supply — Demand Outlook

- Separate information is provided for Vancouver Island (VI), because that is where BC Hydro's customers are most urgently in need of new electricity generating resources for capacity. "Reliability Planning Criteria" are such that the system should be able to withstand the loss of any single element with no loss of customer load. Therefore, VI firm supply is planned with the largest element – one alternating current (ac) cable circuit – unavailable.

Assumptions

- The 2003 Load Forecast is shown with and without the estimated impact of Power Smart programs. Transmission losses have also been included.
- The "Dependable Winter Capacity" of the existing Vancouver Island (VI) hydroelectric Heritage Resources is 450 MW for three hours. Because of the limited storage capacity of the VI hydroelectric plants, 450 MW for three hours is the maximum sustainable peak per day during the winter peak period.
- "Continuous Rating" of the 500 kV ac cables is 1,200 MW. This is the largest or worst single contingency system condition for Vancouver Island. The single contingency firm power transfer capacity for these circuits is the two-hour rating of 1,300 MW.
- The High-Voltage Direct Current (HVDC) cable system brings electricity from the Mainland to VI to meet customers' needs there. Due to its deteriorating condition, its remaining firm (dependable) delivery capability is 240 MW, with expected retirement in 2007.

- The Island Cogeneration Plant (ICP) is currently expected to provide BC Hydro with up to 235 MW of dependable generating capacity by 2005.
- Vancouver Island Call for Tenders — BC Hydro issued a Call for Tenders for up to 300 MW (minimum 150 MW), which is expected to contribute up to 2,100 GW.h. This new Vancouver Island supply also contributes to system supplies of energy and dependable capacity.
- The estimated dependable capacity contribution of new Resource Smart and contracted green resources is 33 MW.



CUSTOMER SERVICE

Customers

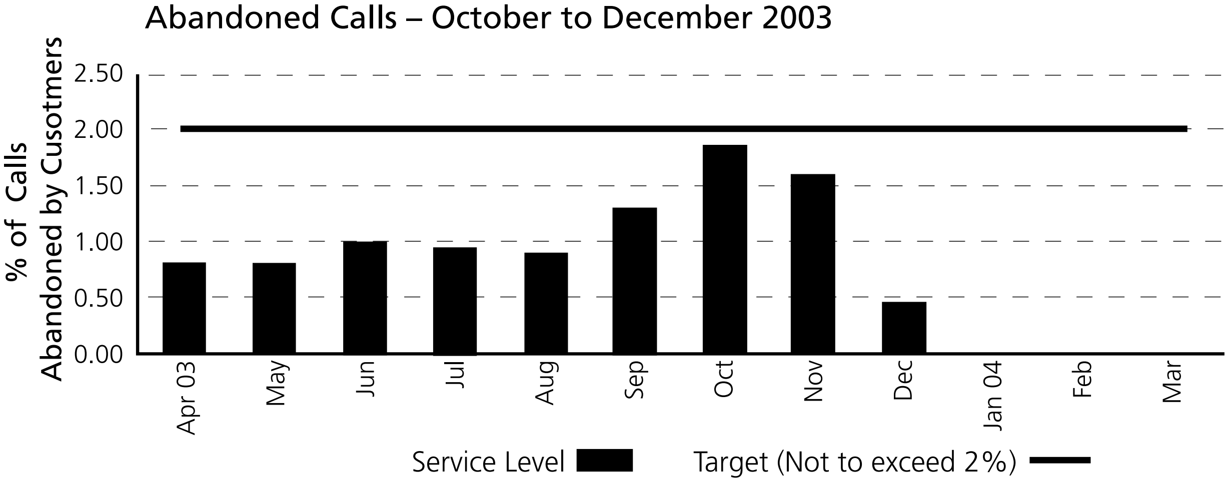
- Net new customer additions totalled 6,527 for the third quarter, an increase of 16.5 per cent over the same period last year. This upward trend is expected to continue for the remainder of the fiscal year, due to the general strength of the economy in the southern part of the province and the volume of initial requests for estimates received from the development community.

Customer Care

- The Service Level chart shows the number of calls to the Customer Care line that were answered within 30 seconds of a caller requesting to speak to a Customer Service Representative (CSR) and exiting the Interactive Voice Response (IVR) system. The Percentage of Total Calls Abandoned shows the number of callers who hung up before being answered by a CSR.
- The downward trend in service level during October and November was due to challenges co-ordinating the Northstar training, Power Smart campaign calls and staffing levels. BC Hydro and Accenture Business Services worked together to identify options and alternatives to improve service levels. This was reflected in the increased service level during December to 90 per cent of calls answered within 30 seconds.
- Abandoned calls showed a similar trend in October and November for the above reasons and showed marked improvement during December.
- In the third quarter of the current fiscal year, the lower call volume trend shown in previous quarters has continued. Total Customer Care calls offered to the IVR for the third quarter of the current fiscal year were approximately 474,900, compared with 634,800 for the same period last year.
- Total Customer Care calls answered by CSRs were just over 329,000 for the third quarter. This compares with 416,700 for the same period last fiscal year.
- In the third quarter of the current fiscal year, the call centre achieved an overall adjusted Customer Care Service level of 81 per cent, which compares favourably with the target of 80 per cent. The adjusted abandonment rate of 1.34 per cent for the quarter also compares favourably with the maximum target of 2.0 per cent.

Customer Care – Accenture Business Services Call Centres
Service Level – October to December 2003

Customer Care – Accenture Business Services Call Centres
Abandoned Calls – October to December 2003



Accenture Business Services

Accenture Business Services of British Columbia assumed responsibility for the performance of all Customer Care functions as of April 1, 2003.

Critical Service Levels	October	November	December
Deposit 98% of payments within agreed timeline	▲	▲	▲
Answer 80% of Customer Care calls within 30 seconds	▼	▼	▲
No more than 2% Customer Care calls abandoned	▲	▲	▲
96% of meters read in accordance with schedule	▲	▲	▲
99.85% of meters are read accurately	▲	▲	▲
84% of customers calling the Call Centre are satisfied or better	▲	▲	▲
Less than 2 errors per month in disconnect advisory process	▲	▲	▲
Less than 2 errors per month in disconnect accuracy	▲	▲	▲
99% of payments posted accurately	▲	▲	▲
98% of reconciliations of bank deposits posted within 4 days	▲	▲	▲
Receivable dollars in arrears per agreement	▲	▲	N/A[1]
# of receivable accounts per arrears	▲	▲	N/A
98% of bills mailed next business day	▲	▲	▲

▲ Met or exceeded target ▼ Did not meet target

[1] Under negotiation and confirmation due to Northstar conversion issues at December month end.

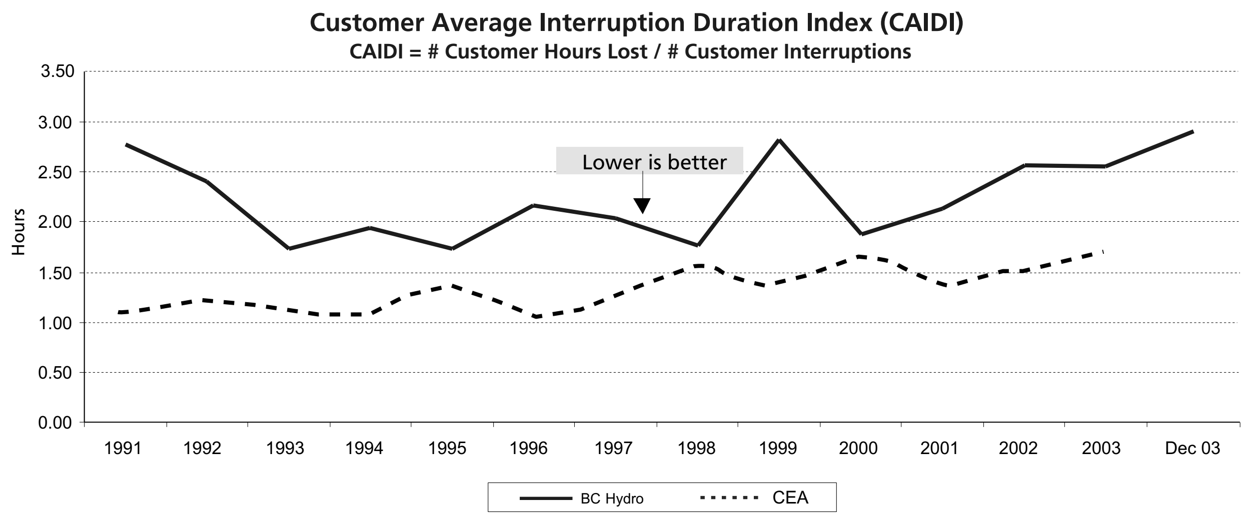
Information Systems & Technology

- Two of the three major IT initiatives "Portal" (Indus PassPort: Work Management and Supply Chain) and "Finance Business Transformation" (PeopleSoft: Financials and Time Capture) have now been in production for almost six months. Post-implementation stabilization and legacy system decommissioning work will continue on them as planned through fiscal 2004.

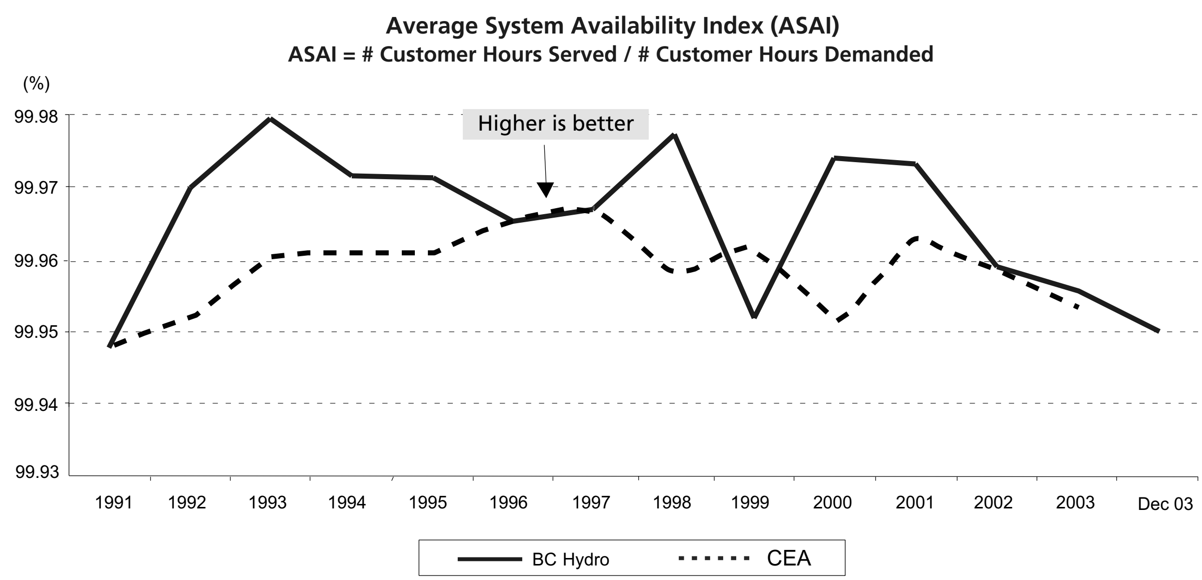
Project NorthStar

- The third initiative "NorthStar" (the implementation of the SAP Customer Care System) was implemented December 29, 2003. Ongoing work is being coordinated between BC Hydro, Northstar Project Team and ABS to manage the "storm" period and ensure customer service levels are maintained while staff become familiar with the new system and more proficient in its use.

Reliability



- Customer average interruption duration index (CAIDI) measures the amount of time an interrupted customer is without power. Although BC Hydro customers have fewer interruptions than the CEA composite, it takes BC Hydro longer to restore service once the interruption has occurred because BC Hydro serves a much larger service territory than most of the utilities in the composite. Secondly, since the majority of the utilities in the composite are municipal utilities operating in relatively compact areas, their service restoration times, including travel time, tend to be relatively shorter. Other contributing factors include the abundance of trees and difficult terrain in British Columbia. CAIDI was higher in fiscal 1999, fiscal 2002 and fiscal 2003 due to adverse weather conditions. For the 12 months ending December 31, 2003, CAIDI was worse than target due to several major weather events as well as the source outage resulting from the McLure forest fire.

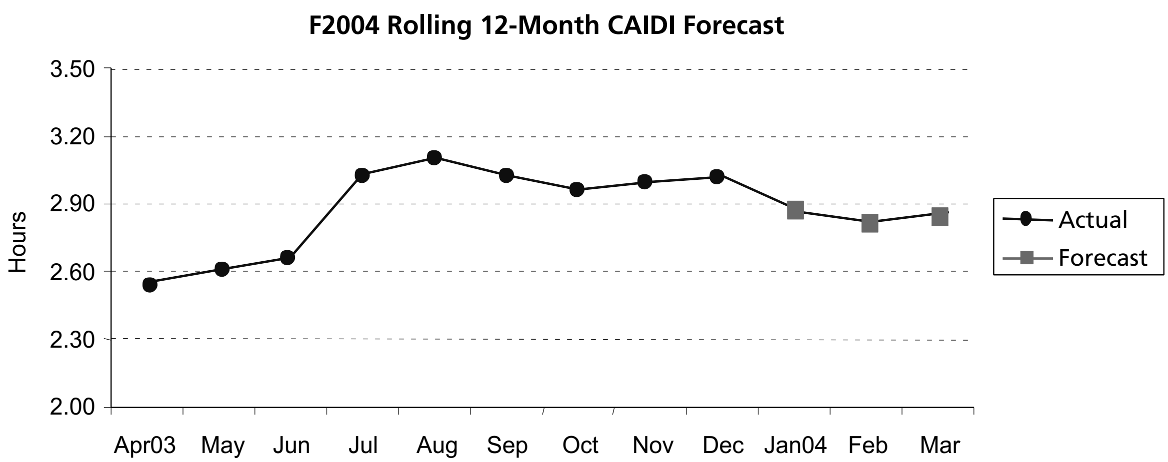


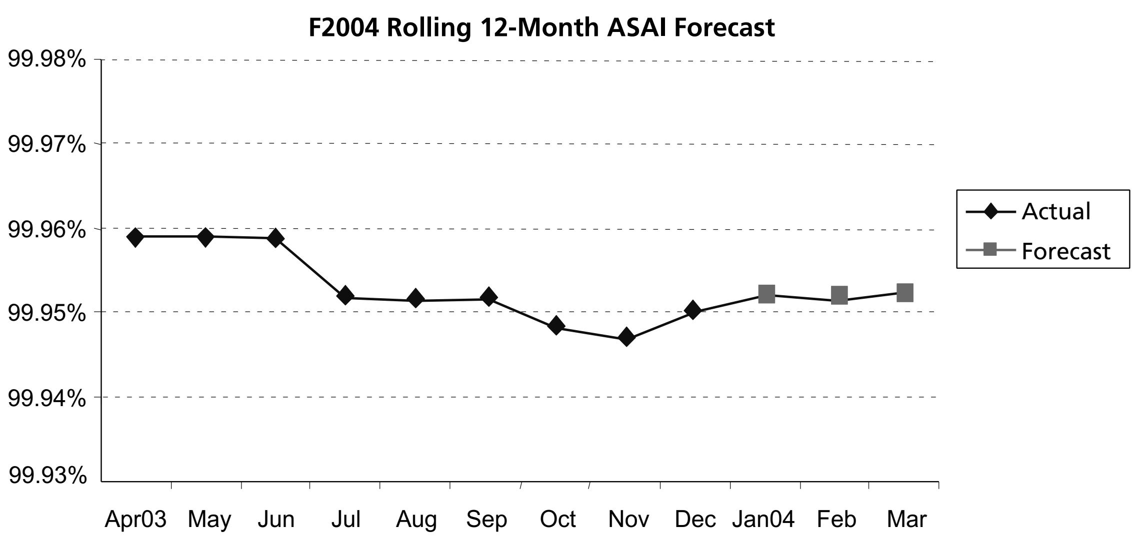
- Average System Availability Index (ASAI) measures the percentage of time during a year that power is available to customers. BC Hydro's performance has been consistently better than the CEA composite. In recent years, although BC Hydro continues to outperform the composite, system performance was adversely impacted by exceptionally severe storms in November 1998 and December 2001. For the 12-month period ended December 31, 2003, ASAI was below target because of several major weather events as well as the source outage resulting from the McLure forest fire. Diesel generators were deployed to supply electricity to the affected customers until transmission service was fully restored on August 21, 2003.

Reliability
(12 months year-to-date to December 31, 2003)

Actual Reliability		Target Reliability
ASAI:	99.950%	99.970%
CAIDI:	2.93 hours	2.15 hours

- For the 12 months ending December 31, 2003, ASAI and CAIDI are below targets as a result of weather-related events and the major source outage caused by the McLure forest fire. These events resulted in much higher-than-expected customer hours lost, relative to the number of customers interrupted. Forecasts for the 12-month rolling average indicate that ASAI and CAIDI will be below target by year-end, albeit improving to 99.955 per cent and 2.81 hours respectively.





ASSETS AND FINANCIAL HIGHLIGHTS

Assets

- The annual Distribution System improvement Recurring Capital Program addresses capacity constraints, reliability, power quality, safety and legal/regulatory issues on the BC Hydro distribution system. Projects have been prioritized to ensure maximum value is derived. Significant projects in fiscal year 2003/2004 include: replacement of faulted feeder and submarine cables, installation of new feeder circuits in the Surrey and Vancouver areas, increased circuit capacity and security of supply to the Gulf Islands and installation of numerous circuit reclosers.
- Improvement work in the Non-integrated Area this year is focused on addressing potential environmental impacts by improving fuel forwarding and oil spill containment systems.

Financial Highlights

Interim Report – Distribution – nine months ended December 31

In millions	2003 actual	2002 actual	% change
External revenues	$1,806.6	$1,720.0	5.0%
Inter-segment revenues	n/a	n/a	n/a
Net income (loss)	$(267.8)	$47.4	665.0%

Highlights Notes:

- Third-quarter revenues year-to-date were higher than for the same period last year due to customer growth, customer revenues relating to wholesale customers ($30 million) previously reported in the Generation LoB, extremely warm weather in July and August 2003 affecting the cooling load, and higher sales to pulp and paper customers.
- Net Loss of $267.8 million year-to-date compared with Net Income of $47.4 million for the same period last year resulted in an unfavourable variance of $315.2 million mainly due to an increase in energy and OMA costs, partly offset by higher revenues. Energy costs increased by $354 million largely due to an increase in the price of energy purchases and the increase in volume of energy required to meet demand. OMA costs are $59 million higher primarily due to additional functions added to Distribution since December 2002, increased trouble costs resulting from Interior forest fires, higher Portal and CIS costs due to timing of project work, increased Customer Care costs due to growth, adjustment for prior years' pension costs and depreciation and finance charges now charged to OMA in addition to ABS direct contract charges.

PERFORMANCE MEASURES – DISTRIBUTION

Distribution's four key goals are:

Strong financial performance — through identification and management of risks associated with the business to ensure optimal decision-making that adds value to our stakeholders and customers.

Quality service — through continuing to better understand customer needs, building on customer relationships and providing differentiated services based on customer needs, and through sustaining and operating a safe and reliable infrastructure at the lowest cost.

Energy management — through optimization of the domestic energy portfolio and through portfolio management techniques to manage the physical and financial supply risk. Performance measures for this goal are being developed and will be benchmarked against the best in class when ready.

Skilled workforce, safe workplace — through development of an interdependent, engaged and competent workforce to make Distribution a Top 50 company in Canada for which to work. (Measured annually with an Employee Commitment Index.)

In addition to the following indicators, Distribution tracks a number of measures either on behalf of BC Hydro overall (Reliability and Incremental Conservation Gigawatt Hours) or that cascade from BC Hydro's overall measures (All Injury Frequency and Approved Strategic Workforce Positions Filled).

Net Income (in Millions) ▲

	Actual	Target
YTD 03/04	$(267.8)	$(347.0)

Net Income is defined as total revenue less total expenses before transfers to the Rate Stabilization Account. The targets are based on current cost and revenue drivers and the impact that cost reduction and/or revenue enhancement initiatives will have on these drivers.

Net Income was better than target, primarily as a result of higher revenues and lower finance charges.

COMA/Customer ●

(Capital and OM&A Cost per Customer)

	Actual	Target
Q3 03/04	$196.8	$194.7

COMA/Customer is defined as gross recurring capital expenditures (net of Telus recoveries) and operating, maintenance and administrative expenses divided by the total number of customers. BC Hydro's new 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.

COMA/Customer was close to target for the third quarter.

Introduction

- Engineering provides project management, maintenance, emergency response, design, contracts and construction management services to the Generation and Distribution lines of business, BCTC and selected external clients. Third-quarter activities have focused on the delivery of engineering services within scope, schedule and budget and with appropriate quality.

Seven Mile Unit 4 / Dam Safety Improvement Projects

- Work on the Seven Mile Dam Safety Improvement Project proceeds on schedule for the completion of site work by December 31, 2004. The installation of 57 large-capacity 92-strand post-tensioned anchors in the dam was successfully completed. The new tower and hoist housing for Spillway Gate 5 were installed.
- The tender for the completion phase of the project, Spillway Completion Contract, was issued in December 2003. This work mainly consists of upgrades to site control and monitoring systems.

2L33 Transmission Cable

- Work continues on schedule for the installation of approximately nine km of high-voltage cable between Horne Payne Substation in Burnaby and Cathedral Square Substation in Vancouver. All cable pulling is complete and cable splicing has been completed in three of 10 manholes. Substation line termination work at Horne Payne substation is complete and is on schedule at Cathedral Square substation for completion in early February. The project remains on track to meet the scheduled April 2004 completion date.

High-Voltage Submarine Cable Replacement

- Replacement of approximately 8.8 km of high-voltage DC submarine cable in the Gulf Islands was completed by a project team from Engineering, Field Services and contractor personnel with an in-service date of December 8, 2003. These cables are a critical component of the transmission link from the Mainland to Vancouver Island. The work was carried out in a challenging marine environment during winter conditions while meeting stringent schedule, safety, and environmental targets. The project included recovery of 8.8 km of existing cable, supply of five km of new cable, installation of 8.8 km of new and spare cable and completion of shore-end work for the cables.

Financial Performance

- Key financial metrics for Engineering for the third quarter of fiscal 2004 are:

Metric	FY04-Q3	Year to Date
Utilization (hourly)	83.0%	84.2%
Billable hours	196,000	602,000

- Utilization is defined as the percentage of available hours (approximately 1,600 hours per employee) of all staff, that has been charged to billable work (work authorized by LOBs or external clients).

Financial Highlights

Interim Report – Engineering – nine months ended December 31

In millions	2003 actual	2002 actual	% change
External revenues	$2.1	$2.5	–16%
Inter-segment revenues	$63.7	$56.0	13.8%
Net income (loss)	$(0.1)	$1.2	–108.3%

Highlights Notes:

- Inter-segment revenues are higher than last year due to higher Billable Hours and because fiscal 2004 revenues include contract hires.
- Net Income is lower, mainly due to timing differences for internal expenses (Variable Pay). The annual forecast of zero Net Income remains unchanged.

PERFORMANCE MEASURES — ENGINEERING

Engineering's three key goals are:

Maximize financial performance

Improve client focus

Ensure skilled workforce, promote entrepreneurial team

The following indicators measure these goals. In addition to these indicators, Engineering tracks a number of measures that cascade from BC Hydro's overall measures.

Utilization Rate ●

	Actual	Target
Q3 03/04	83.0%	82.4%

Utilization Rate is defined as billable hours divided by total hours worked. Targets have been set based on moving towards first quartile when compared with other engineering firms.

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

Hourly Charge-out Rate ●

	Actual	Target
Q3 03/04	$95.60	$95.33

Hourly Charge-out Rate 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.

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

Client Feedback/Satisfaction ●

	Actual	Target
Q3 03/04	6.0	5.5

Client Feedback/ Satisfaction is defined as client ratings of Engineering's performance on:

- Understanding of client's business
- Delivering on time
- Delivering on budget
- Communication
- Quality of products and services
- Overall satisfaction

A face-to-face meeting is conducted once a week with different clients within BC Hydro and scored on a scale of 1 to 7 (1: Extremely Poor to 7: Excellent). Targets have been set based on Engineering keeping near the upper end of the range.

The Client Feedback/ Satisfaction measure for the third quarter was on target.

% of Approved EIT and GTT Positions Filled ▼

	Actual	Target
Q3 03/04	83%	100%

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.

EIT/GTT hiring has been completed for fiscal 2004. Percentage of EIT and GTT Positions Filled is below target, as all positions identified were not required due to staffing strategy.

Introduction

- Field Services, through its own workforce and the contractors that it administers, provides service restoration, maintenance, construction (civil, electrical and mechanical), telecommunications maintenance, public safety, vehicle and vegetation services to the three BC Hydro Lines of Business – Transmission, Distribution and Generation. Field Services' primary role is to work safely to keep the lights on while providing customers with high-quality service at low cost.

Employee and Customer Safety

- Field Services continues to drive its effort in reaching "Zero" injuries. Participation by all staff, management and labour, remains a cornerstone for improved safety performance.
- The continued emphasis on management presence in the workplace, coupled with reinforcement of safe work behaviours and recognition of successes, has contributed to a reduction of 10 reportable incidents over the third quarter of last year, a 48-per-cent decrease. This translates into a rolling 12-month Field Services All Injury Frequency (AIF) of 4.5 with a year-to-date AIF of 4.6.
- The delivery of public safety programs for schools and first responders for the nine months of fiscal 2004 has seen activity across the province. School safety programs have been delivered to approximately 22,600 students and first responder programs to over 2,500 attendees.

Building a Strong and Capable Workforce

- Field Services continues to invest in building a highly skilled workforce with trainees accounting for nine per cent of the regular employee base. Field Services is on track with the fiscal 2004 targeted intake of new apprentices and other trainees, except for one strategic workforce planning (SWFP) manager program that has been reviewed downward. The Youth Trade Hire program, which was successfully completed this quarter, employed 18 temporary workers this past summer.
- Rollout of the Training and Qualification Tracking System (TQTS) was completed this quarter. The system reports that close to 1,200 Field Services employees have completed the Code of Conduct training and that the SafeStart refresher classes are fully subscribed. Thirty-three on-line Power Line Technicians have been rolled out through TQTS, thereby eliminating all labour-intensive paper-based processes. The system has become a gateway to certification tools, learning materials and on-line learning events.

Service Restoration/Customer Reliability

- Field Services continues to focus on service restoration and customer reliability as part of its core service offering. Field Services has experienced approximately 10 per cent fewer trouble calls in the first nine months of the year than the same period in last year, primarily due to reduced lightning-related outages. A large system event during the second quarter resulted in heavy fire damage to both transmission and distribution circuits, mainly in the South Interior of the province. Field Services quickly mobilized its workforce and restored power under some very difficult conditions.

Financial Summary

- Field Services has been created as a cost recovery business unit within BC Hydro, and for the nine months ended December 31, 2003, recoveries have marginally exceeded costs by 3.2 per cent. Field Services recoveries were $256 million, compared with a Plan of $215 million. Recoveries reflect services provided to internal BC Hydro Lines of Business customers as well as third-party customers external to BC Hydro. The higher-than-Plan recoveries are mainly related to increased recoveries on labour, vehicles and materials.

- Internal recoveries account for 95 per cent of the total recoveries. Approximately 76 per cent of these recoveries are derived from an internal Field Services trade workforce, with the remaining 24 per cent from external Contractor workforces.
- Total Field Services chargeable hours exceeded Plan by 174,000 hours, with 1,450,000 chargeable hours billed to date. The chargeable hours utilization (total number of chargeable hours divided by the total number of hours available) is approximately 75 per cent. Under current billing practices, management, supervisory and administrative time is not billed separately to customers but is factored into the chargeable hourly rate.

Financial Highlights

Interim Report – Field Services – nine months ended December 31

In millions	2003 actual	2002 actual	% change
External revenues	$12.5	$7.3	71%
Inter-segment revenues	$203.3	$159.0	28%
Net income	$8.0	$0.5	1,500%

Highlights Notes:

- Increased volume of work resulted in additional recoveries from Field Services clients.
- A $2.0 million credit was issued to the Lines of Business this quarter.

PERFORMANCE MEASURES — FIELD SERVICES

Field Services' three key goals are:

Strong financial performance — by improving cost performance while maintaining and improving service.

Quality service — by focusing on customer satisfaction and service reliability.

Safe workplace, skilled workforce — by providing employees a safe, healthful, and harassment-free workplace through continual improvement and ensuring safety remains a top priority, and by retaining and developing the skills and knowledge of employees and contractors.

The following indicators measure these goals. In addition to these indicators, Field Services tracks a number of measures that cascade from BC Hydro's overall measures.

Utilization Rate ●

	Actual	Target
Q3 03/04	74.7%	69.5%

Labour Utilization 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.

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

Hourly Charge-out Rate ●

	Actual	Target
Q3 03/04	$96	$96

Hourly Charge-out Rate 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.

The Hourly Charge-out Rate measure is on target.

% of Total Planned Work Complete ●

	Actual	Target
Q3 03/04	100%	98%

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. 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.

Percentage of Total Planned Work Completed is on target.

All Injury Frequency ▲

	Actual	Target
Q3 03/04	4.6	5.9

All Injury Frequency is defined as the combination of Medical Aid Injuries and Disabling Injuries. Medical Aid Injuries are injuries where a medical practitioner has submitted a fee to Workers' Compensation Board for services rendered and the duration the employee was absent from work did not exceed the normal shift of the day of injury. Disabling Injuries are injuries that involve the employee being absent for more than the day of injury. The calculation is based on injuries experienced in Field Services over the previous 12 months and it is relative to person-hours that have been worked over that same period.

All Injury Frequency was significantly better than target for the quarter, primarily as a result of continued management emphasis on safety. Management has been reinforcing the message by spending more time with the crews and reinforcing safety messages via the "SAFE START" program and following up more on corrective action plans. Variable pay contracts have also brought about a greater awareness of safety in the field. Overall, the field/crews have a greater awareness of safety issues.

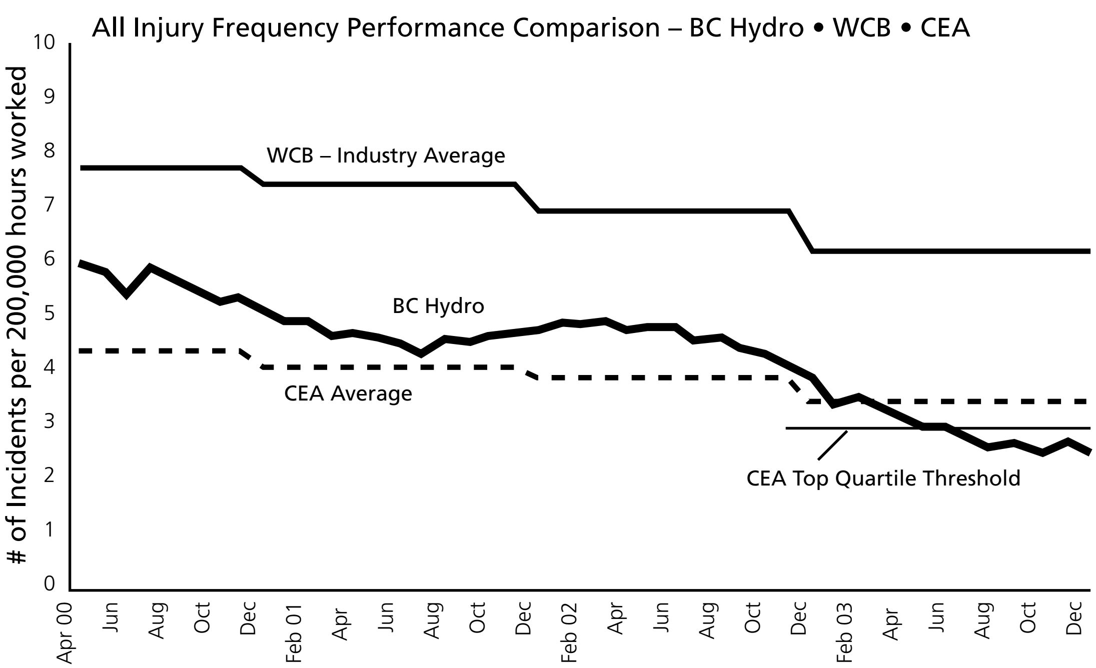
Total Trainees –
Strategic Workforce Planning ●

	Actual (YTD)	Target (Annual)
Q3 03/04	99	122

Total Trainees – Strategic Workforce Planning 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.

The selection process for 15 new Power Line Technician apprentices was concluded and postings for the Strategic Workforce Planning Manager and Meter Technicians were prepared in the third quarter. It is anticipated that these additional hires in the fourth quarter will result in approximately 120 apprentices on the system by year-end. This year-end forecast will be slightly below the target of 122 due to several early graduations.

- BC Hydro is committed to being recognized as a top-quartile performer in occupational safety and health. One of the ways BC Hydro measures its performance in this area is by comparing the "All Injury Frequency Rate" (AIF) with other Canadian electric utilities. AIF is an industry standard calculation of the total number of disabling and medical treatment injuries per 200,000 hours worked.
- The improving trend continued once again through this quarter, with continued reductions in both injury frequency and severity. The current AIF is 2.7, indicating that BC Hydro is continuing to perform better than the year-end target of 3.0.
- Highlights from this quarter include the completion of the multi-year conversion to an ISO-style Safety Management System. This performance-based process defines corporate expectations for how safety will be managed, yet it allows for line management to develop and implement safety plans that meet the specific needs of BC Hydro's very diverse workforce.
- Learning from mistakes is essential to BC Hydro's success. Including near-miss incidents, where no property damage or injuries occurred, 107 incidents were investigated and 283 corrective actions were implemented in the first three quarters of fiscal 2004. Those corrective actions have substantially reduced the risk of these incidents happening again.
- BC Hydro is committed to continuous improvement in safety and to achieving its goal of zero injuries. These efforts are paying off. Over the past two years, 104 fewer employees have been injured on the job.



- To ensure that BC Hydro will be able to sustain its core operations, a strategic workforce planning initiative (SWfP) has been underway since fiscal 2001 to mitigate the impact of retirements and renew critical workforce capability. Each year, initiative funding has been targeted to enable hiring of apprentices and trainees in trades, engineering, technical and management positions. A total of 226 positions were funded in fiscal years 2001 to 2003, bringing the total investment to $19 million. An additional $10.3 million has been allocated to sustain the SWfP initiative in fiscal 2004.
- As shown below, 74 per cent or 59 of the 80 planned positions for the fiscal year were filled during the first, second and third quarters.

	Planned Full Year (80)	Filled YTD (44)
Generation	11	9
Distribution	8	7
Engineering	18	15
Field Services	33	25
Transmission (BCTC)	10	3
Total Planned & Filled	80	59

Footnotes
G: final two positions are on hold due to impacts by revamped BCTC training program and reorganization
D: hiring underway for final position
FS: Q3 hiring targets met
E: three GTT positions no longer required – staffing strategy change
BCTC: will not meet hiring targets due to revamping of job competencies and training programs

- Employee attrition (from BC Hydro excluding BCTC), which includes retirements, resignations and other terminations, was running at 4.6 per cent or 165 employees at the end of the third quarter. Retirements represented the major component of attrition, with 121 regular employees retiring or completing pre-retirement leaves by the end of the quarter. In total, 570 employees are eligible or will become eligible to retire with unreduced pension in fiscal 2004, but many will choose to defer retirement.

- BC Hydro filed its first revenue requirements application in almost 10 years on December 15, 2003, with the British Columbia Utilities Commission (BCUC) requesting a general rate increase of 7.23 per cent effective April 1, 2004, and a further increase of two per cent effective April 1, 2005. Key cost drivers putting upward pressure on rates include increases in the cost of new energy supply, maintenance and capital expenditures, pension costs, demand-side management program spending, provision of transmission services and costs of managing environmental and First Nations issues.
- The process of reviewing and determining the appropriate rates for BC Hydro is anticipated to be lengthy and will not be completed by April 1, 2004. Thus, BC Hydro is seeking interim rate relief effective April 1, 2004, to permit it an opportunity to earn its allowed return on equity in fiscal 2005. Along with the application, BC Hydro submitted a proposed regulatory schedule that was discussed at a pre-hearing conference on January 14, 2004. BC Hydro convened a Revenue Requirements Workshop on January 15, 2004, to discuss the information contained in the application. The Commission issued an Order on January 16, 2004, establishing the regulatory timetable for review of the application with an oral hearing commencing in Vancouver on May 17, 2004. On January 23, 2004, the BCUC approved the first-year increase of 7.23 per cent on an interim basis, effective April 1, 2004. Public hearings will begin on May 17, 2004, to determine the final rate increase.
- On October 17, 2003, the BCUC submitted its recommendations to the provincial government concerning the implementation of a Heritage Contract between BC Hydro Generation and Distribution to preserve the value of BC Hydro's existing, low-cost electricity generation for British Columbians. It adopted BC Hydro's proposal, which will maximize the value of this existing generation and have all of the trade benefits up to $200 million per year accrue to BC Hydro's ratepayers, thus satisfying the Energy Plan's objectives of low electricity rates and secure, reliable supply. The BCUC noted that with this model it is not necessary for Powerex to be regulated and recommended that the appropriate level of regulatory oversight be limited to a review of the income statement of Powerex. The BCUC also made recommendations on the appropriate design of a stepped rate for BC Hydro's transmission voltage customers. It accepted most of BC Hydro's proposals but recommended that the Tier 2 (stepped) rate should reflect the long-term opportunity cost of new supply rather than being based on market indexes as BC Hydro had suggested.

  On November 28, 2003, the government accepted these recommendations and is implementing them through special directions to BC Hydro and to the Commission. Heritage Special Direction to the BCUC (HC2) requires the Commission to treat the Heritage Contract attached to HC2 as legally binding for rate-making purposes, the effect of which is to require BC Hydro to continue to deliver energy at cost-based rates. The Heritage Contract will be for a minimum of 10 years and it will continue unless the government decides it wants to terminate, in which case five years' notice of termination must be given.
- The review of the Georgia Strait Crossing Canada (GSX) Pipeline project has been completed with the issuance by the National Energy Board on December 15, 2003, of a Certificate of Public Convenience and Necessity (CPCN) to GSX Pipeline Limited (Certificate GC-109). This was preceded by the federal government's response on November 21, 2003, accepting the Joint Panel Review's (JRP) conclusion that the Canadian portion of the GSX pipeline is unlikely to cause significant

environmental effects, provided that mitigation measures proposed by the JRP in its report to the government are undertaken. On November 28, 2003, the JRP issued its decision to approve the GSX pipeline subject to fulfilment of 33 certificate conditions, including regulatory approval of the Vancouver Island Generation Project. All conditions must be satisfied by December 31, 2005 to enable construction of GSX to commence; otherwise the certificate will expire. On December 11, 2003, federal Governor in Council approval of the CPCN was granted.

- As a result of the September 8, 2003, decision denying a CPCN for the Vancouver Island Generation Project (VIGP), BC Hydro is proceeding with a Call for Tenders (CFT) for capacity and associated energy supply on Vancouver Island. On October 23, 2003, BC Hydro asked the Commission to review and make a determination on the appropriateness of the terms of the CFT and related documents early on in the process, thus reducing regulatory risk for bidders making investments to participate in the tender. On January 23, 2004, the BCUC provided a response on the Vancouver Island CFT process. BC Hydro is reviewing the BCUC response.
- On November 3, 2003, BC Hydro filed its application for approval of a net metering tariff with the BCUC. This was in response to a recommendation from the Commission that BC Hydro should develop such a rate and the Energy Plan's view that this would help electric utilities achieve the voluntary goal of 50 per cent of new supply from BC Clean electricity over the next 10 years. A written hearing process has been established by the Commission to review BC Hydro's proposed tariff and a decision is expected by spring 2004.

ACCENTURE BUSINESS SERVICES OF BC (ABS) OUTSOURCING

- ABS assumed responsibility for the performance of certain functions for BC Hydro on April 1, 2003. These included:
  - Customer Services
  - Information Technology
  - Human Resources
  - Financial Systems
  - Purchasing
  - Building and Office Services
- At a very high level, the agreement represents a commitment on BC Hydro's part to outsource services of $1.6 billion over 10 years in exchange for contractually committed savings of $250 million over the same period. The contract also benefits BC Hydro by ensuring that current performance and service levels are retained, or increased to first-quartile performance by the end of the third year of the contract.
- Results to date indicate that the BC Hydro – ABS relationship continues to be positive. BC Hydro is receiving service at the levels received prior to the outsourcing agreement on the vast majority of metrics in the contract, and in many instances, service performance is exceeding the targets set. Financially, the actual expenditure to date is 0.1 per cent better than target, indicating that the savings budgeted in year one of the contract are being realized.
- The first year of the outsourcing agreement has been identified as a Transition Year. A year-long transition plan has been developed and remains on track, with the majority of key milestones met. Communication, change management and governance frameworks continue to be key areas of focus during this transition year.

Introduction

- British Columbia Transmission Corporation (BCTC) is a provincial Crown corporation, independent from BC Hydro, which has full responsibility for operating, maintaining and planning transmission assets. BCTC reports to the Minister of Energy and Mines and will be regulated by the British Columbia Utilities Commission (BCUC).
- BCTC provides open and non-discriminatory access to the B.C. transmission system for all electricity producers in the province. BCTC will also direct new investment in transmission infrastructure upon receiving approval from the BCUC. The BCUC will continue to regulate the terms and rates for transmission services. A 10-member BCTC Board has been appointed, and BCTC officially began operations on August 1, 2003.

Highlights

BCTC

- On November 21, 2003, the Lieutenant Governor in Council designated Key Agreements between BC Hydro and BCTC, pursuant to the Transmission Corporation Act. The agreements officially took effect on December 1, 2003, and formally define BCTC's role to independently operate, maintain and plan the transmission system on behalf of BC Hydro.
- In December 2003 BCTC began work on creating its own tariff, which will be submitted to the BCUC for review and approval in mid-2004, and will likely come into effect on April 1, 2005. Once its own tariff is in effect, BCTC will become a separate, regulated utility.
- On December 15, 2003, BC Hydro filed its Revenue Requirements Application with the BCUC. In this application, BCTC is responsible for developing and defending before the Commission all aspects of the revenue requirement related to operating, managing and planning BC Hydro's transmission system, except the cost of financing the transmission assets, which remains BC Hydro's responsibility. After BCTC has secured its own transmission tariff, it will file separate revenue requirements with the BCUC.

RTO West

- During the quarter, BCTC continued to work with nine western U.S. utilities on the development of Regional Transmission Organization (RTO) West, including co-ordination of B.C. operations with the regional organization. If RTO West is formed, it is expected to be fully operational in about four years. BC Hydro also continues to be involved in developing B.C.'s positions in the RTO West stakeholder consultations in the Pacific Northwest.

Vancouver Island Supply

- The final work on the replacement of a five-kilometre section of offshore high-voltage direct-current (HVDC) submarine cable (Cable 5) was completed in December 2003. This cable, along with another newly replaced cable (Cable 9), is helping meet winter peak requirements on Vancouver Island.

Metropolitan Vancouver Cable Project

- Work continued this quarter on the installation of cable circuit 2L33, which will secure reliable supply to downtown Vancouver. This upgrade is part of BCTC's long-term development plan for the metropolitan system to address aging infrastructure and seismic concerns. The $44 million project continues to be on budget and on schedule for completion in May 2004. Approximately $27.6 million has been expended to date on this project.

Operational Issues

- The electricity grid was exposed to the highest recorded solar disturbance (level K-9) between October 28 and 30. The grid has been designed to minimize the risk of this exposure and, as a result, no significant impacts were observed during that period.
- Construction of BC Hydro's Guichon Series Capacitor Station, located near Logan Lake, was completed. The station is operating as part of the 500 kV transmission grid connecting the South Interior to the Lower Mainland.

Financial Highlights

Interim Report – British Columbia Transmission Corporation – nine months ended December 31

In millions	2003 actual	2002 actual	% change
External revenues	$9.3	$7.9	+18%
Inter-segment revenues	$495.1	$593.8	–17%
Net income	$118.3	$220.1	–46%
Capital expenditures	$140.5	123.8	+13%

Highlights Notes:

- Revenues below prior year due to lower Point-to-Point volumes (50-per-cent decrease) and lower Point-to-Point prices (37-per-cent decrease).
- Net Income below prior year due to lower revenues as mentioned above and higher maintenance expenditures, offset by lower business sustaining costs.
- Capital expenditures above prior year due to an increase of $20 million in this year's annual plan.

PERFORMANCE MEASURES — BRITISH COLUMBIA TRANSMISSION CORPORATION

Transmission's four key goals are:

Independent business structure — through the formation of a new transmission company, independent of BC Hydro, that is commercially viable and stakeholder focused.

Workforce expertise and competency — through development of an interdependent, professional, competent workforce who are excited about achieving Transmission business goals.

Meet the energy transfer needs of our customers — through enhancing and sustaining the transmission infrastructure to reliably meet the needs of our domestic customers and by ensuring that the investment made in transmission assets is protected.

Enable the new electricity marketplace — through meeting the needs of stakeholders for open access to the transmission system, efficient and effective electricity markets in B.C., and participation in wider regional markets.

The following indicators measure these goals. In addition to these indicators, Transmission tracks a number of measures that cascade from BC Hydro's overall measures.

Net Income (in Millions) ▲

	Actual	Target
YTD 03/04	$118.3	$109.8

Net Income is defined as total revenue less total expenses before transfers to the Rate Stabilization Account. The targets are based on current cost and revenue drivers and the impact that cost reduction and/or revenue enhancement initiatives will have on these drivers.

Net Income was better than target, primarily as a result of lower planned asset-related costs partially offset by lower Point-to-Point revenue.

OMA/GW.h-km ▼

	Actual	Target
Q3 03/04	10.3¢	10.1¢

OMA / GW.h-km is defined as operating, maintenance and administrative expenses divided by the gigawatt hours transmitted over kilometres of Transmission circuit. Gigawatt hours include both domestic and Powerex sales. While the OMA / GW.h-km measure itself does not have an industry benchmark, Transmission placed in the second quartile in terms of cost per structure kilometre in the last PA Consulting benchmarking study.

OMA / GWh-km was higher than target, primarily as a result of lower gigawatt hours delivered.

Customer Satisfaction ▲

	Actual	Target
Q3 03/04	0 Complaints	3 Complaints

Customer Satisfaction is defined as the number of complaints received from customers that were identified at, or escalated to, the vice-presidential level in BCTC. Targets were set based on historical performance.

For the third quarter, no complaints were identified at the vice-presidential level.