Third Quarter Report

For the nine months ended December 31, 2001

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1. OVERVIEW

Net income of $181 million for the nine months ended December 31, 2001, was $383 million lower than that earned during the same period last year. Before any transfers to the Rate Stabilization account, net income was $1,145 million lower than that earned in the prior year. A number of non-controllable factors including low water inflow levels, which were one of the lowest on record, a dramatic decline in market prices for energy since late June 2001, and the effects of the slowing North American economy have had a significant negative impact on BC Hydro's earnings this year. BC Hydro has tried to mitigate the impacts of these factors by using various strategies including optimizing the operation of its system.

KEY HIGHLIGHTS

- The Kinbasket Reservoir on the Columbia River System is currently at historic lows due to the drought conditions experienced in the region. The Williston Reservoir on the Peace River System is within its normal operating range. The low level of inflows combined with a decline in market prices resulted in an increase in energy purchases to meet domestic demand.
- Revenues of $5,363 million were $188 million lower than the prior year. This decrease was largely due to lower electricity trade revenues earned during the second and third quarters of this year.
- Expenses of $4,759 million increased by $962 million from the same period in the prior year. The increase was primarily a result of higher energy costs primarily due to the impact of low water inflows and to higher prices for energy purchases during the first quarter of the year.
- BC Hydro's forecast income for fiscal 2002 is approximately $200 million. Based on this forecast, a transfer of approximately $200 million will be required from the Rate Stabilization Account (RSA) in order for BC Hydro to earn its allowed return on equity. This will leave approximately $30 million in the RSA at the end of the year.
- On August 21, 2001, the provincial government extended the current freeze on electricity rates to all customers until March 31, 2003. This extension will allow for completion of the Provincial Energy Policy Review and the Provincial Core Review Process.
- BC Hydro is in the process of a Core Services Review to examine all aspects of operations to ensure that they are as effective and efficient as possible. The Review will evaluate alternative ways of doing business and serving customers and examine other ideas or options to ensure the best delivery of services.

- On October 4, 2001, BC Hydro announced the issuance of Requests for Expression of Interest (RFEI) to examine business interest in key areas of BC Hydro. The RFEI is part of the Core Services Review and is used to assess interest from the private sector in possible joint venture partnerships or other arrangements for providing services to BC Hydro. A total of 90 parties contacted BC Hydro regarding the RFEI, of which 19 chose to submit formal proposals.
- On December 19, 2001, BC Hydro announced that it will be entering into discussions with a preliminary short list of the proponent groups. The submissions from these groups came closest to meeting our RFEI objectives.
- In the early morning hours of Friday, December 14, 2001, one of the worst wind storms in B.C. history hit the Lower Mainland, Sunshine Coast and parts of Vancouver Island. Sustained winds of 80 kph (gusting to 110 kph) rated this storm behind only those from 1998 and 1996 in terms of impacts. As a result more than 150,000 customers – about 10 per cent of the BC Hydro system – lost their power. This situation was further compounded in the early morning hours of December 15, when major transmission lines to Vancouver Island failed due to excessive ice buildup. These lines carry approximately 75 per cent of Vancouver Island's electricity needs. BC Hydro responded to these events as it always does by mustering all available resources and working as quickly as possible to execute repairs and return services to customers. Final costs for storm cleanup and infrastructure replacement were $2.1 million.

Vancouver Island Generation Project

- Work continued with Calpine Canada during the Third Quarter on siting a new generating facility on Vancouver Island to meet customers' growing electricity needs.
- The initial location of choice was in Port Alberni and an application was filed with the Environmental Assessment Office (EAO) for a possible site there in the early fall.
- On October 19, 2001, the EAO Executive Director referred the project to "Stage 2" of the EAO process, extending the review period significantly. On October 22, 2001, Port Alberni City Council voted not to introduce a re-zoning amendment that was required for the project to proceed at the proposed site.
- The combination of these two activities made it clear that BC Hydro would not be able to meet its schedule and in-service date. As a result, on November 28, 2001 BC Hydro formally notified all parties that it was withdrawing its application for Port Alberni.
- At the same time, BC Hydro and Calpine Canada began looking at other potential sites on Vancouver Island.
- Sites in North Cowichan and the Regional District of Nanaimo were among those considered before the Duke Point area of Nanaimo was announced as the preferred area.

Georgia Strait Crossing Pipeline Project

- The proposed GSX pipeline will provide firm natural gas transportation to Vancouver Island to support the existing Island Cogeneration Project (ICP) and new generation projects in the future.
- An application for the GSX project has been filed with the National Energy Board (NEB) and the Federal Energy Review Commission (FERC). On September 20, 2001, the NEB announced the membership of the Joint Panel who will review the project. Public information sessions were held by the NEB during the third week of October.
- On November 9, 2001 the NEB issued Directions on Procedure for the Joint Panel Review. Included in these were dates for public consultation sessions (to begin in January 2002) as well as a public hearing date for the project of June 17, 2002.

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 2001 Annual Report of BC Hydro and the consolidated financial statements of BC Hydro for the nine months ended December 31, 2001 and 2000. 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.

RESULTS OF OPERATIONS

Low water inflows into BC Hydro reservoirs have had a significant negative impact on earnings this year. The impact of the slowing US economy and the dramatic collapse of market prices for electricity since late June 2001 have also had a negative influence on electricity trade revenues in the second and third quarters of this year. Net income, before the Rate Stabilization Account transfer, of $181 million for the nine months ended December 31, 2001, was $1,145 million lower than for the same period in the previous year.

Domestic Revenues

Total domestic revenues of $1,775 million for the nine months ended December 31, 2001, increased $13 million from the prior year. The increase was primarily due to higher miscellaneous revenues resulting from an increase in transmission wheeling earlier in the year. As part of open access to BC Hydro's transmission lines, BC Hydro sells transmission to customers transmitting wholesale electricity. An increase in revenues from residential and commercial customers due primarily to customer growth also contributed to an increase in domestic revenues. These increases were partly offset by a decrease in revenues from large industrial customers particularly in the pulp and paper sector. This decrease in revenues largely occurred in the third quarter of this year and reflects the general slowdown in the economy and weak commodity prices.

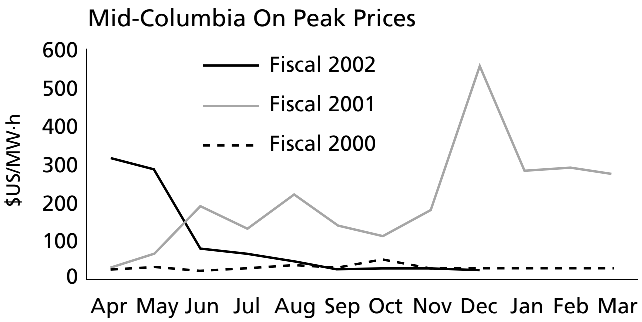
Electricity Trade Revenues

Electricity trade revenues were $3,588 million for the nine months ended December 31, 2001, a decrease of $201 million from the same period last year. Strong revenues during the first quarter of this year, due primarily to higher market prices earlier in the year, have been more than offset by declining revenues during the second and third quarters of this year. The third quarter of this year has been hit especially hard by the dramatic decline in market prices experienced since late June 2001. This decline in market prices has been caused primarily by a reduction in demand due to the slowdown in the US economy, conservation measures and mild weather conditions in California and its surrounding regions. Powerex, BC Hydro's electricity subsidiary continues to work with legal counsel to protect its interests regarding prior sales to California.

The following table compares electricity trade revenues for each quarter of this year compared to the prior year. The average sale price during the second quarter of this year was significantly higher than market because BC Hydro had locked in high priced forward sales before the market prices fell. BC Hydro could not lock in forward sales to the same degree for the third quarter, because of credit limits on most counterparties and because BC Hydro was forecast to be a net importer of energy for the quarter in order to meet domestic demand.

	Fiscal 2002				Fiscal 2001			
	1st Qtr	2nd Qtr	3rd Qtr	Total	1st Qtr	2nd Qtr	3rd Qtr	Total
Revenues (in millions)	$ 1,860	$ 1,247	$ 481	$ 3,588	$ 692	$ 1,544	$ 1,552	$ 3,789
Volumes (in GW·h)	4,940	6,254	5,528	16,722	5,467	7,484	6,457	19,408
Average Sale Price ($/MW·h)	$376.50	$199.40	$87.00	$214.60	$126.50	$206.30	$240.60	$195.20

The following graph compares the electricity market prices over the last few years. Market prices at the mid-Columbia trading hub in central Washington state are shown as they are indicative of prices in the Pacific Northwest.



Expenses

Energy costs of $3,943 million for the nine months ended December 31, 2001, increased by $937 million from the same period last year due largely to non-controllable factors such as low water inflows and market prices for energy purchases. The majority of this increase occurred during the first quarter of this year and was due primarily to an increase in the average price of energy and gas purchases. The average price of electricity purchases was $207/MW·h for the first quarter of this year compared to $64/MW·h during the same period last year. Drought conditions that were at record levels on the Columbia River System also resulted in an increase in energy purchases to meet demand during the first half of this year and to conserve reservoir levels. Hydro generation was reduced by approximately 20 per cent this year due largely to lower water inflows which were 88 per cent of normal. The availability of low-cost hydro generation has a significant impact on energy costs as the variable cost of hydro generation is substantially less than the cost of electricity purchases or natural gas purchases used primarily for the Burrard Generating Station.

Energy costs of $695 million for the third quarter of this year were $782 million lower than for the same period in the prior year. This decrease was primarily due to lower electricity purchase prices which averaged $80/MW·h this quarter compared to $181/MW·h during the third quarter of the prior year. Lower energy purchase volumes largely due to the decrease in electricity trade activity also contributed to the decline in energy costs this quarter.

Operations, maintenance and administration (OMA) expenses of $403 million for the nine months ended December 31, 2001 increased by $12 million from the same period last year. This increase was largely due to an increase in maintenance and emergency repair costs primarily at the Burrard Generating Station. An increase in legal and other associated costs related to dealings with California trade partners also contributed to the increase. As part of its efforts to be a sustainable energy company, BC Hydro, in Fiscal 2001, committed to removing and destroying all PCBs located on its properties and equipment over the next several years. As a result, a significant provision for costs relating to the removal and destruction of all known PCBs on BC Hydro owned properties and equipment situated in sensitive areas was recorded in the second quarter of the prior year. Prior to this program, BC Hydro generally removed PCBs from equipment when the equipment was taken out of service.

Finance Charges

Finance charges for the nine months ended December 31, 2001 of $423 million decreased by $5 million from the same period last year. A lower average volume of debt and lower short-term interest rates were the primary reasons for the decrease. The impact of a weaker Canadian dollar vis-à-vis the US dollar, particularly during the third quarter of this year, partly offset the favorable variance. BC Hydro maintains a portion of its core debt portfolio in US dollars primarily to match US dollar revenues from electricity trade sales.

Rate Stabilization Account

The Rate Stabilization Account (RSA) is used to mitigate the impact of fluctuating earnings on customers. In years when BC Hydro's actual return on equity is in excess of that allowed by the British Columbia Utilities Commission (the Commission), a transfer is made from income into the RSA. In lower-income years, when BC Hydro's return on equity is below that allowed, a transfer is made from the RSA, if there is a balance, to offset any rate increase that may be needed to allow BC Hydro to earn its allowed return on equity. There was no transfer to the RSA for the nine months ended December 31, 2001 compared to a $762 million transfer in the prior year.

INVESTING ACTIVITIES

Capital expenditures for the nine months ended December 31, 2001 amounted to $361 million compared with $278 million for the same period in the prior year. Generation upgrade and plant reliability and safety projects accounted for $89 million in expenditures for the nine months ended December 31, 2001, an increase of approximately $17 million from the same period in the prior year. Distribution system expansion and improvements to service customer growth accounted for $110 million in expenditures for the nine months ended December 31, 2001 which was similar to the same period in the previous year. The remaining capital expenditures of $162 million relating to transmission line, substation, computer, and control and communication projects were approximately $64 million higher than in the prior year. This increase was primarily due to an increase in IT expenditures relating to replacement of some legacy systems and software upgrades together with expenditures relating to a cable replacement project. These cables located in Burnaby, B.C. were originally installed in the late 1950's and had reached their design life and needed to be replaced. BC Hydro spending is currently below its Capital Plan for the year due primarily to the delay in the start of some projects.

As BC Hydro's assets continue to age, they will have to be replaced to maintain system reliability. BC Hydro's current replacement capital ratio (defined as sustaining capital expenditures as a per cent of the replacement value of capital assets) is in the range of 1 to 1.5 per cent. This ratio is expected to increase in the next several years as BC Hydro's assets continue to get closer to the end of their expected lives. The replacement value of BC Hydro's assets is currently estimated at approximately $35 billion versus its net book value of approximately $9.5 billion. The replacement value is based on the Handy Whitman index, a common index used by utility companies.

FINANCING ACTIVITIES

BC Hydro issued $200 million of Canadian long-term debt with an interest rate of 6.35 per cent during the nine months ended December 31, 2001. The proceeds from these issues were used to fund capital expenditures and operations together with financing the call of a $100 million Canadian bond, which carried an interest rate of 14.5 per cent, and the maturity of a $4 million Canadian bond, which carried an interest rate of 9.75 per cent.

BUSINESS RISKS/UNCERTAINTIES

BC Hydro is subject to various risks and uncertainties that causes 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 policies influence both the operation of the BC Hydro system and its earnings. While these risks and uncertainties generally cannot be eliminated as they are largely non-controllable, some may be mitigated to a certain degree. BC Hydro's net income forecast for this fiscal year is estimated to range between $150 million and $350 million with the probable forecast estimated at $200 million. BC Hydro's earnings will vary due largely to non-controllable factors during this winter such as ice flow conditions on the Peace River system, temperatures, snowpack conditions and market prices for energy.

BASIS OF PRESENTATION

The accounting policies and methods of application used in the preparation of these interim consolidated financial statements are consistent with the accounting policies used in the Company's year end audited consolidated financial statements of March 31, 2001. These consolidated financial statements do not include all disclosures required for annual financial statements, and therefore these statements should be read in conjunction with the consolidated financial statements for the year ended March 31, 2001, as set out in the 2001 Annual Report.

CONSOLIDATED STATEMENT OF OPERATIONS (UNAUDITED)

	For the Three Months Ended December 31		*For the Nine Months Ended December 31*	
in millions	**2001**	2000	**2001**	2000
Revenues				
Residential	**$ 266**	$ 265	**$ 638**	$ 628
Light industrial and commercial	**226**	226	**649**	641
Large industrial	**117**	137	**366**	391
Other energy sales	**24**	22	**61**	60
Miscellaneous	**16**	18	**61**	42
Domestic revenues	**649**	668	**1,775**	1,762
Electricity trade	**481**	1,553	**3,588**	3,789
	1,130	2,221	**5,363**	5,551
Expenses				
Energy costs	**695**	1,477	**3,943**	3,006
Operations, maintenance and administration	**140**	113	**403**	391
Taxes	**43**	40	**130**	126
Depreciation and amortization	**95**	92	**283**	274
	973	1,722	**4,759**	3,797
Income Before Finance Charges and Transfer to Rate Stabilization Account	**157**	499	**604**	1,754
Finance charges	**140**	137	**423**	428
Income Before Transfer to Rate Stabilization Account	**17**	362	**181**	1,326
Transfer to Rate Stabilization Account		305		762
Net Income	**$ 17**	$ 57	**$ 181**	$ 564

CONSOLIDATED STATEMENT OF RETAINED EARNINGS (UNAUDITED)

	As at December 31	
in millions	**2001**	2000
Retained earnings, beginning of year	**$1,459**	$1,385
Net income	**181**	564
Payment to the Province	**(144)**	(472)
	$1,496	$1,477

CONSOLIDATED STATEMENT OF CASH FLOWS (UNAUDITED)

in millions	*For the Three Months Ended December 31* 2001	2000	*For the Nine Months Ended December 31* 2001	2000
Operating Activities				
Net income	**$17**	$57	**$181**	$564
Adjustments for:				
Depreciation and amortization	**95**	92	**283**	274
Rate stabilization account	**–**	305	**–**	762
Other non-cash items	**29**	15	**25**	(5)
	141	469	**489**	1,595
Working capital changes	**(120)**	46	**(560)**	(125)
Cash (used for) provided by operating activities	**21**	515	**(71)**	1,470
Investing Activities				
Loan receivable	**–**	(1)	**22**	(1)
Capital asset expenditures	**(133)**	(93)	**(411)**	(271)
Contributions in aid of construction	**16**	12	**48**	33
Demand side management programs	**5**	–	**3**	(1)
Future removal and site restoration costs	**(1)**	(2)	**(4)**	(5)
Proceeds from property sales	**–**	1	**1**	1
Cash used for investing activities	**(113)**	(83)	**(341)**	(244)
Financing Activities				
Bonds, notes and debentures:				
– issued	**200**	–	**200**	450
– retired	**–**	(179)	**(104)**	(179)
Revolving borrowings	**96**	(112)	**181**	(491)
Sinking fund changes	**(8)**	45	**38**	17
Premium, discount and issue costs	**8**	–	**8**	17
Settlements of financial instruments	**–**	–	**–**	3
Cash (used for) provided by financing activities	**296**	(246)	**323**	(183)
Payment to the Province	**–**	–	**(372)**	(343)
Increase (Decrease) in Cash	**204**	186	**(461)**	700
Cash at Beginning of Period[2]	**21**	519	**686**	5
Cash at End of Period[2]	**$225**	$705	**$225**	$705
Supplemental Disclosure of Cash Flow				
Interest paid	**$99**	$129	**$403**	$441

Notes:

1. Certain figures for the prior year have been restated to conform to presentation in the current fiscal year.
2. Cash at the beginning and end of the period consists of temporary investments.

CONSOLIDATED BALANCE SHEET (UNAUDITED)

in millions	As at December 31 2001	As at March 31 2001
ASSETS		
Capital Assets		
Capital assets in service	$ 14,575	$ 14,323
Less accumulated depreciation	5,510	5,256
	9,065	9,067
Unfinished construction	377	294
	9,442	9,361
Current Assets		
Temporary investments	225	686
Accounts receivable and accrued revenue	432	345
Materials and supplies	89	81
Prepaid expenses	60	82
Unrealized gains on mark-to-market transactions	5	113
	811	1,307
Other Assets and Deferred Charges		
Loan receivable	–	22
Sinking funds	1,163	1,148
Demand-side management programs	99	116
Deferred debt costs	604	633
Foreign currency contracts	31	28
	1,897	1,947
	$ 12,150	$ 12,615
LIABILITIES AND EQUITY		
Long-Term Debt		
Long-term debt net of sinking funds	$ 7,192	$ 6,900
Sinking funds presented as assets	1,163	1,148
	8,355	8,048
Foreign Currency Contracts	14	9
Current Liabilities		
Accounts payable and accrued liabilities	551	1,121
Accrued interest	157	124
Accrued Payment to the Province	144	372
Unrealized losses on mark-to-market transactions	4	108
	856	1,725
Deferred Credits and Other Liabilities		
Provision for future removal and site restoration costs	155	144
Deferred revenue	245	217
Rate stabilization account	232	232
Contributions arising from the Columbia River Treaty	214	221
Contributions in aid of construction	583	560
	1,429	1,374
Retained Earnings	1,496	1,459
	$ 12,150	$ 12,615

OPERATING HIGHLIGHTS (UNAUDITED)

	For the Three Months Ended December 31		*For the Nine Months Ended December 31*	
in GW·h	**2001**	2000	**2001**	2000
Electricity Sold				
Residential	**4,385**	4,367	**10,343**	10,182
Light industrial and commercial	**4,266**	4,252	**12,203**	12,033
Large industrial	**3,536**	4,023	**11,028**	11,628
Other energy sales	**484**	463	**1,110**	1,144
	12,671	13,105	**34,684**	34,987
Electricity trade	**5,528**	6,457	**16,722**	19,408
	18,199	19,562	**51,406**	54,395

BUSINESS OF BC HYDRO

British Columbia Hydro and Power Authority is a provincial Crown corporation. BC Hydro's Board of Directors is appointed by the Lieutenant Governor in Council and is responsible for the overall direction of the company.

As one of the largest electric utilities in Canada, BC Hydro serves close to 1.6 million customers in an area containing over 94 per cent of British Columbia's population. Between 43,000 and 54,000 GW·h of electricity are generated annually, depending upon prevailing water levels, with more than 80 per cent produced by major hydroelectric generating stations on the Columbia and Peace rivers. Electricity is delivered to customers mainly through an interconnected system of more than 75,000 kilometres of transmission and distribution lines. BC Hydro provides among the lowest electricity rates in North America.

REGULATION

BC Hydro is regulated by the British Columbia Utilities Commission (the Commission), and they are both subject to directions issued by order of the Province. Under Special Direction No. 8, the Commission must allow BC Hydro to achieve a return on equity equal to the return allowed, on a pre-income tax basis, by the most comparable investor-owned energy utility. In the event that BC Hydro's actual return on equity is in excess of that allowed by the Commission, a transfer from net income to the Rate Stabilization Account (RSA) is required for the excess. Where BC Hydro earns a return on equity below that allowed, and there is a balance in the RSA, a transfer from the RSA is required to offset the need for a rate increase. Under Special Directive No. 4, BC Hydro is required to make an annual payment to the Province equal to approximately 85 per cent of its net income, after any Rate Stabilization Account transfers.

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

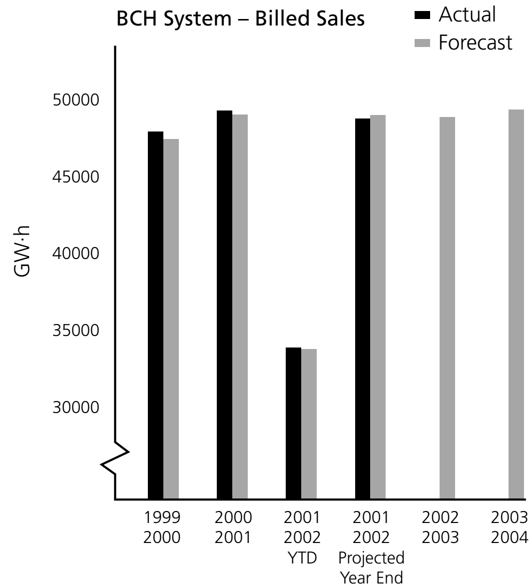
Michael Costello
President and
Chief Operating Officer

3. ELECTRICITY LOAD

BC HYDRO SYSTEM - FISCAL YEAR TO DATE REVIEW

Energy Sales

Nine months into the fiscal year the variance in total billed sales was +32 GW·h or +.09%. Despite all the economic uncertainties, lower industrial sales were compensated by higher residential sales overall. Cooler-than-normal temperatures between April and October, resulted in higher electric heating load, increasing residential sales. The decline in commercial sales was mainly due to the drop in economic activities since mid-summer. Transmission sales were running above forecast until the end of October. Reduction in sales due to the economic slowdown was offset by increased sales to pulp producers that depend on hydro electricity generation due to the lower than expected water levels that have prevailed throughout the province.

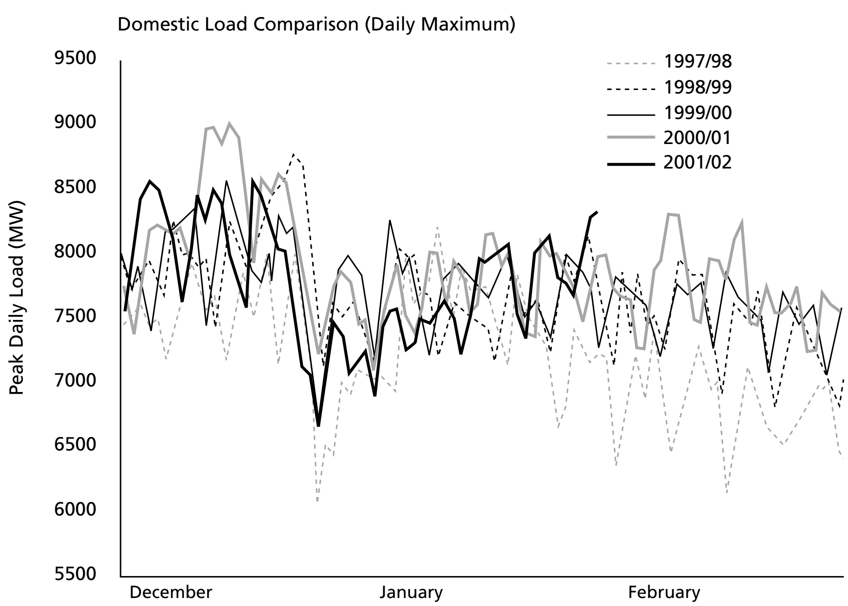


Peak Demand

The highest peak demand to date this winter was 8,692 MW which occurred on December 4, 2001, at a daily average temperature of +2.2°C. The peak demand forecast for this winter is 9,028 MW based on a design daily average temperature of -6.8°C. Peak demands that occurred since December 4 were lower mainly due to production curtailments by major pulp and paper producers.

BC Hydro System - Short Term Forecast

The assumption is that monetary and fiscal measures brought in by Governments and Central Banks around the world throughout 2001 will generate more economic activities. However, a resumption of economic growth is not expected until well into 2002.



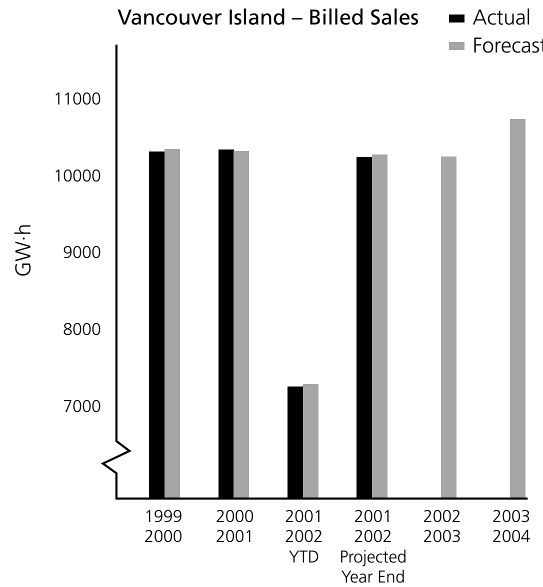
VANCOUVER ISLAND – FISCAL YEAR TO DATE REVIEW

Energy Sales

Nine months into the fiscal year the variance in total billed sales was -88 GW·h or -1.2%. Lower industrial sales were compensated by higher residential sales overall. Dominant industries on VI are related to the forestry sector: pulp and paper, wood manufacturing, and chemical production. Industrial customers consume about 40% of total energy sales to VI. As a result, reduction in demand for forestry exports has a greater impact on industrial electricity sales on VI. Industrial sales were -163 GW·h or -5.2% due to curtailment shutdowns required by major forestry sector producers to reduce inventory. Tourism is a large industry on VI. Commercial sales were -29 GW·h or -1.7% because of lower-than-expected sales to VI's service-producing industries. These sales continue to be lower than expected due to a slow down in the international economy.

Peak Demand

The highest peak demand to date this winter was 1,955 MW which occurred on December 17, 2001, at a daily average temperature of +3.8°C. The peak demand forecast for this winter is 2,139 MW based on a design daily average temperature of –4.4°C. Extensive curtailment shutdowns at three large pulp and paper mills on VI since December 19 will remain a factor as far as the actual VI peak demand for this winter is concerned. These three mills have a combined coincident peak load of about 400 MW. Although operation has resumed since the second week of January, these mills are not expected to return to full production until the second quarter of 2002 at the earliest.



Short Term Forecast

A U.S. led economic recovery will benefit BC overall, and will increase electricity sales to VI in particular because sales to industrial customers on VI are largely related to the production of pulp and paper and lumber. Japan is also a major market for lumber producers along the B.C. coast and they would benefit from an economic recovery there (although economic growth in Japan is likely to remain sluggish in the short term). The assumption is that global demand for forestry products will gradually increase, and some improvement in electricity sales to VI will occur through the course of 2002 as a result.

BC Hydro actively tracks market information that forms the basis for its future price forecasts for both natural gas and electricity. The price of natural gas is significant since gas-fired generation comprises a significant proportion of electricity supply outside of BC Hydro's domestic market.

MARKET FORWARD 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. In the case of electricity, the nearest (liquid) delivery point is Mid-Columbia, and in the case of natural gas the nearest delivery point is Sumas. Forward prices for both electricity and natural gas can be volatile; however, they provide an important near term reference point since they reflect all the information currently available to market participants. Price volatility in these markets arises from the uncertainty surrounding important future events that can affect either the supply of or demand for the underlying commodity. Market forward quotes are readily available for a period of up to two years for electricity and for three to five years for gas and provide useful perspectives of future price expectations supplemented by an analysis of prevailing market fundamentals.

LONGER TERM MARKET FUNDAMENTALS

The number and volume of trades in the forward markets declines for contracts going further out into the future and other sources of information on key drivers of electricity and gas prices are extracted to forecast over the longer term. Longer-term forecasts are available from a number of specialized forecasting groups who analyze long-term market fundamentals considered to be important drivers of electricity and gas prices. The longer-term forecast is based on representing the supply and demand for electricity and of cost drivers expected to prevail. Key factors are the expected stock and availability of generating units especially new units, the expected level of fuel prices and other costs of operating generating units, the level of demand as driven by forecasts of economic activity, technology, and conservation efforts, and the expected state of the regulatory or market environment. BC Hydro acquires the output and market analysis of a number of third party forecasts to supplement its long term forecasting activities.

2002 compared to 2001

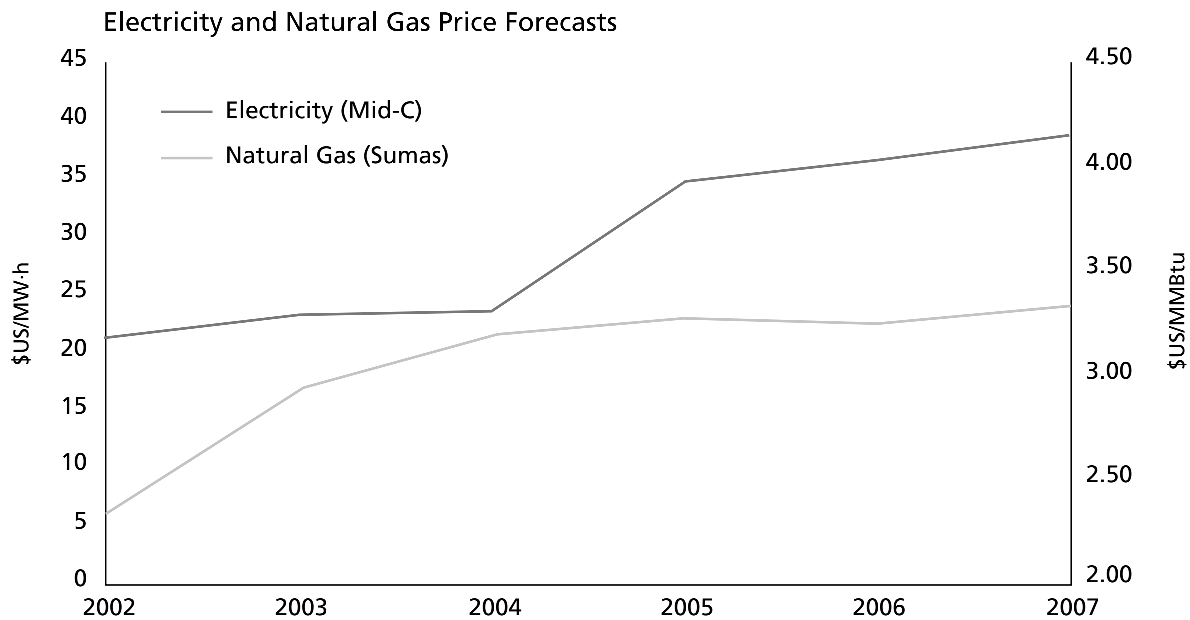
At present, near term prices for both electricity and natural gas appear to be at a low point but show signs of a modest recovery in late 2002. These price expectations contrast with last years high prices which were primarily fueled by a tight supply/demand balance. The US economy has since moved into recession, which has resulted in reduced demand for both natural gas and electricity. Further, this reduction in demand has occurred just as significant new generating supply and natural gas wells began to come into service. Gas storage inventories have risen to near capacity levels and improved hydro conditions have added to the significant supply overhang relative to demand. Lower prices have resulted in lower high load hour to low load hour differentials, since these tend to be positively correlated with price levels.

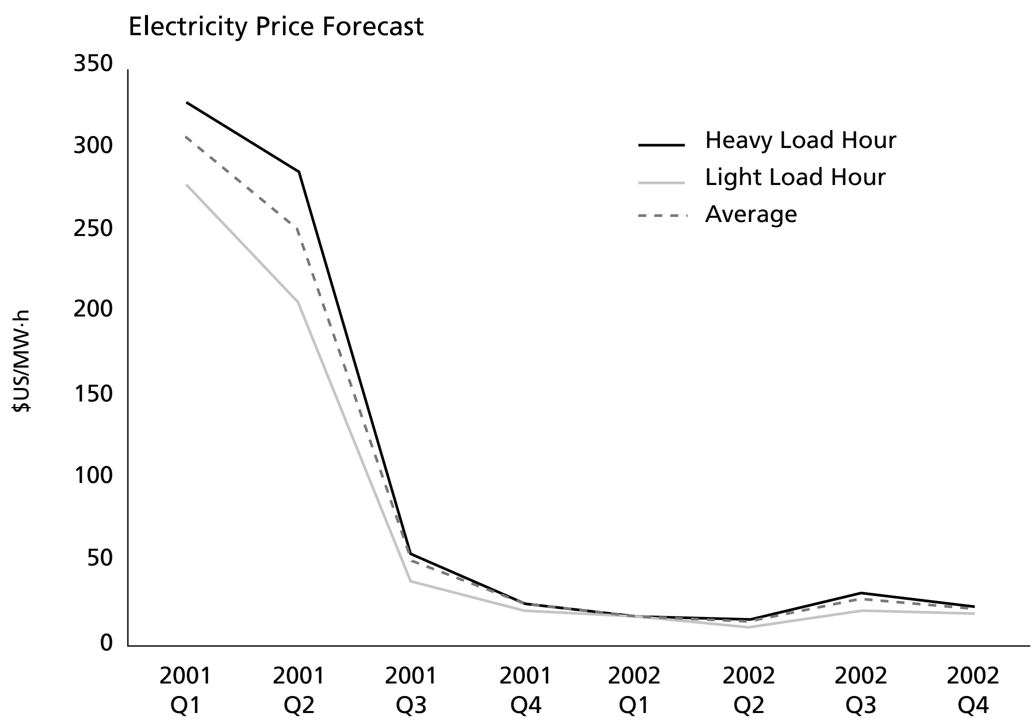
2002/03 Outlook

While near term future prices are low, most macroeconomic forecasts point to a recovery by the beginning Q3 or Q4 of this year. Low natural gas prices have already led to a decline in exploration and drilling, and a decline in natural gas production is expected to follow. With supply beginning to decline and demand poised to increase as the economy improves, gas prices are expected to rise later in 2002.

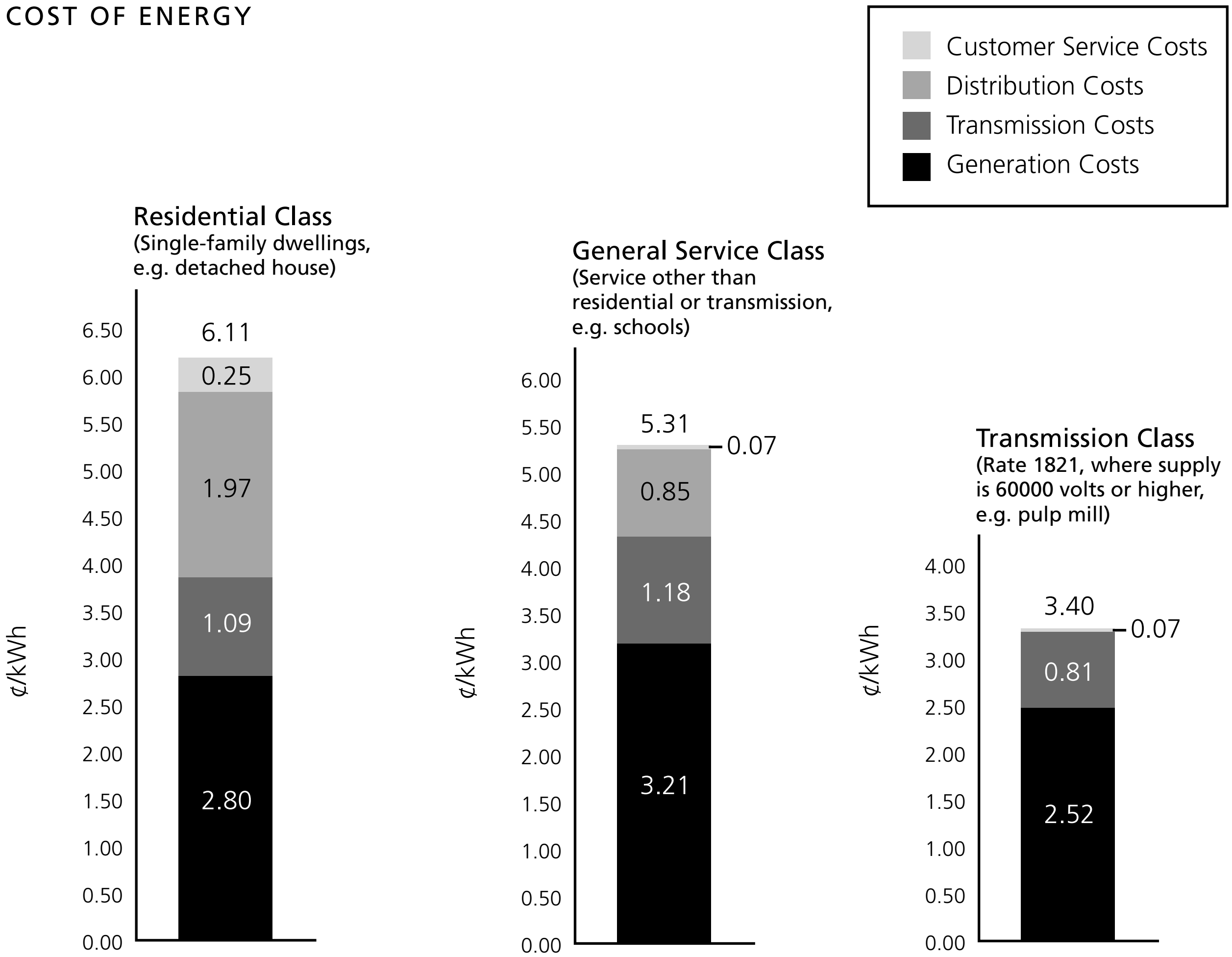
The combination of higher prices for natural gas and increasing electricity demand will generally lead to an increase in electricity prices. However, other factors may delay the price recovery. A significant amount of new generating capacity is already in an advanced stage of development. Even though many projects have been canceled or shelved, it is likely that new production capacity will dampen the demand driven upward pressure in electricity prices. Moreover, hydro conditions for the coming year currently look to be average which will augment supply and work to maintain lower prices in the absence of significant demand growth.

In the longer term, price expectations are based on moving toward a supply demand balance reflective of average economic growth and demand. Prices of both electricity and gas are expected to grow moderately, modulated by seasonal factors.





COST OF ENERGY



RATE STRUCTURE

Generation Costs

Direct and allocated costs incurred to generate or procure electricity for use in B.C. Includes water rental fees, energy purchases, natural gas fuel (for thermal plants) and other costs required to operate BC Hydro's generating system.

Transmission Costs

Direct and allocated costs incurred to transmit electricity on the high-voltage transmission system, from the point of generation or purchase, to the electricity delivery point, or the low-voltage distribution system. These include metering, transformation costs and all other costs related to the BC Hydro Transmission system.

Distribution Costs

Direct and allocated costs incurred to transmit electricity on the low-voltage distribution system to the end user, or customer. These include metering, transformation costs, and other costs related to the BC Hydro Distribution sytem.

Customer Service Costs

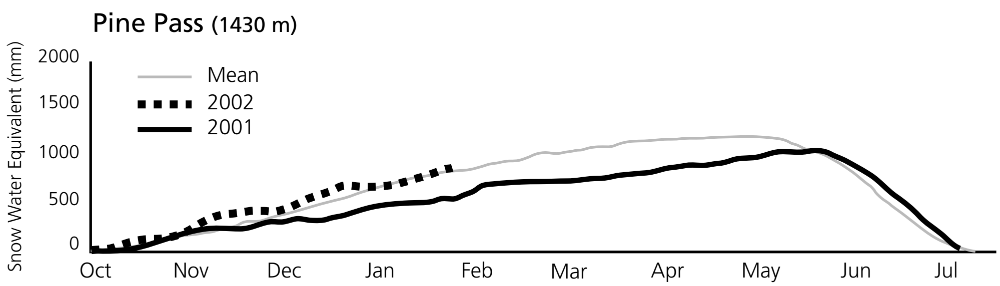
Customer service costs includes all functions related to customer services such as billing, call centre, account inquiries and marketing.

SNOW PACK

BC Hydro has significant reservoirs on both the Peace and Columbia River systems, as well as smaller reservoirs on the coast and Vancouver Island. As a result, it monitors snowpack levels closely throughout the year, as they help determine the ultimate water levels in these reservoirs. The most accurate system reading will occur with the onset of the spring freshet (likely in April) but initial forecasts are made by mid-February.

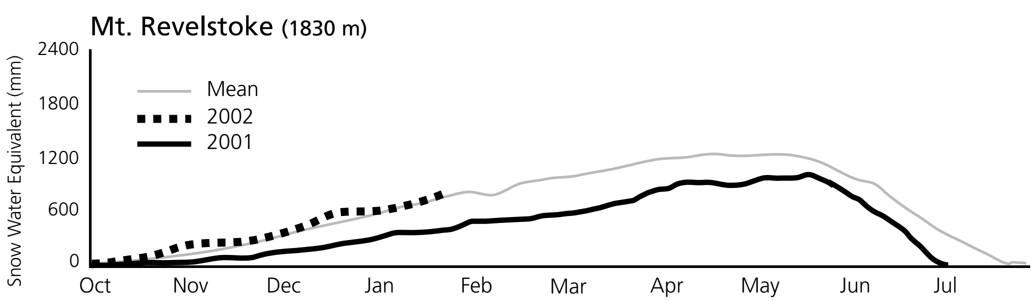
Williston

The water supply forecast for the Williston reservoir (on the Peace River) for February through September 2002 is slightly above average. The current snowpack conditions in the watershed are near to slightly above average for this time of year. The following plot shows the accumulated snow water equivalent at a representative "snow pillow" recording station within the watershed. For Williston, the average snowpack component (October – April) is 51%, while the average rainfall component (May – September) is 49%.



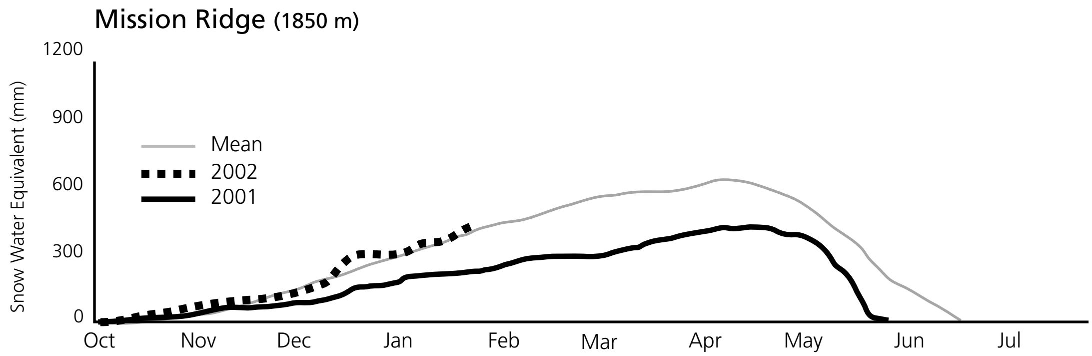
Columbia

The water supply forecast for the Canadian Columbia River projects for February through September 2002 is slightly below average. The current snowpack conditions in the basin are near average for this time of year. The following plot show the accumulated snow water equivalent at a representative "snow pillow" recording station within the watershed. For Kinbasket reservoir (the major Columbia reservoir), the average snowpack component (October – April) is 68%, while the average rainfall component (May – September) is 32%.



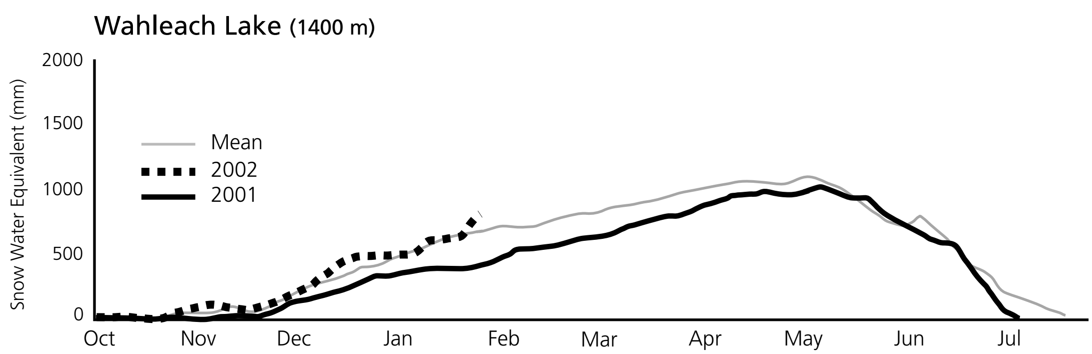
Bridge River

The water supply forecast for Bridge River for February through September 2002 is near average. The current snowpack conditions in the basin are near average for this time of year. The following plot shows the accumulated snow water equivalent at a representative “snow pillow” recording station within the watershed.



Coastal Projects

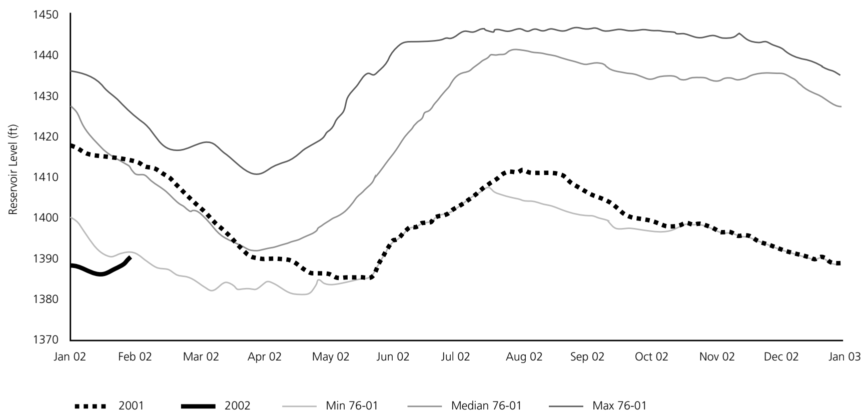
The water supply forecast for projects on the South Coast and Lower Mainland and Vancouver Island for February through September 2002 is near average. The current snowpack conditions in the basin are near average for this time of year. The following plot shows the accumulated snow water equivalent at a representative “snow pillow” recording station within the region.



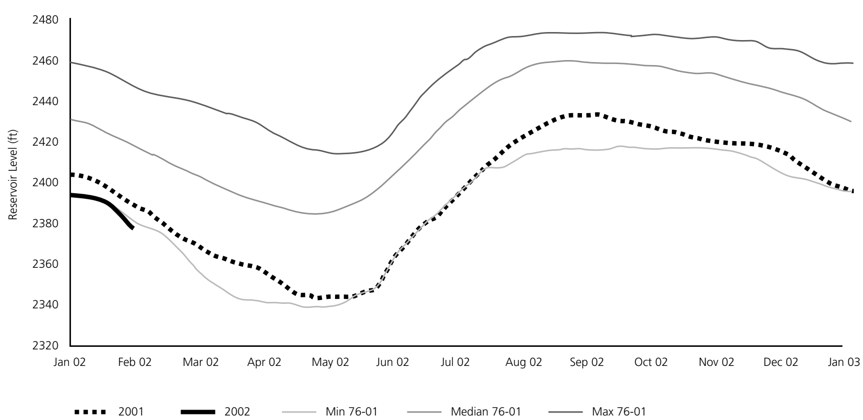
RESERVOIR LEVELS

BC Hydro monitors the levels at all of its hydroelectric reservoirs to ensure the most efficient system integration and operation. The relative reservoir levels at any time are a function of precipitation (rain and/or snow that fills the reservoir) and electricity demand (as the water in the reservoirs is used to turn turbines and produce electricity).

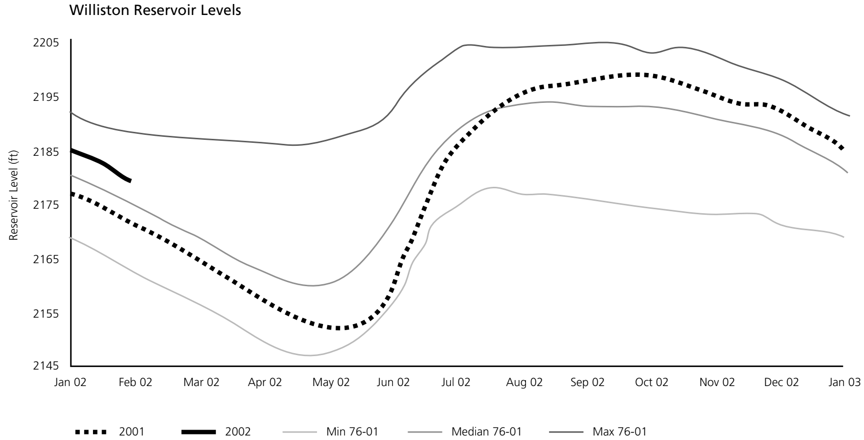
Arrow Reservoir Levels



Kinbasket Reservoir Levels



Williston Reservoir Levels



MAJOR OUTAGES

BC Hydro takes great care to maintain the hydroelectric and thermal generating facilities in its system. As much as possible, outages are scheduled to minimize any financial or customer impacts. The following are large unit outages planned for the Hydro system, through to March 31, 2002:

Peace Generation
GM Shrum - 4 units, total of 6 weeks
Peace Canyon - 4 units, total of 5 weeks

Upper Columbia
Mica - 4 units, total of 4 weeks
Revelstoke - 4 units, total of 4 weeks

Kootenay Gen Area
Seven Mile - 1 unit for 4 weeks, plus minor inspections
Kootenay Canal - 4 units, total of 5 weeks

BURRARD GENERATING STATION

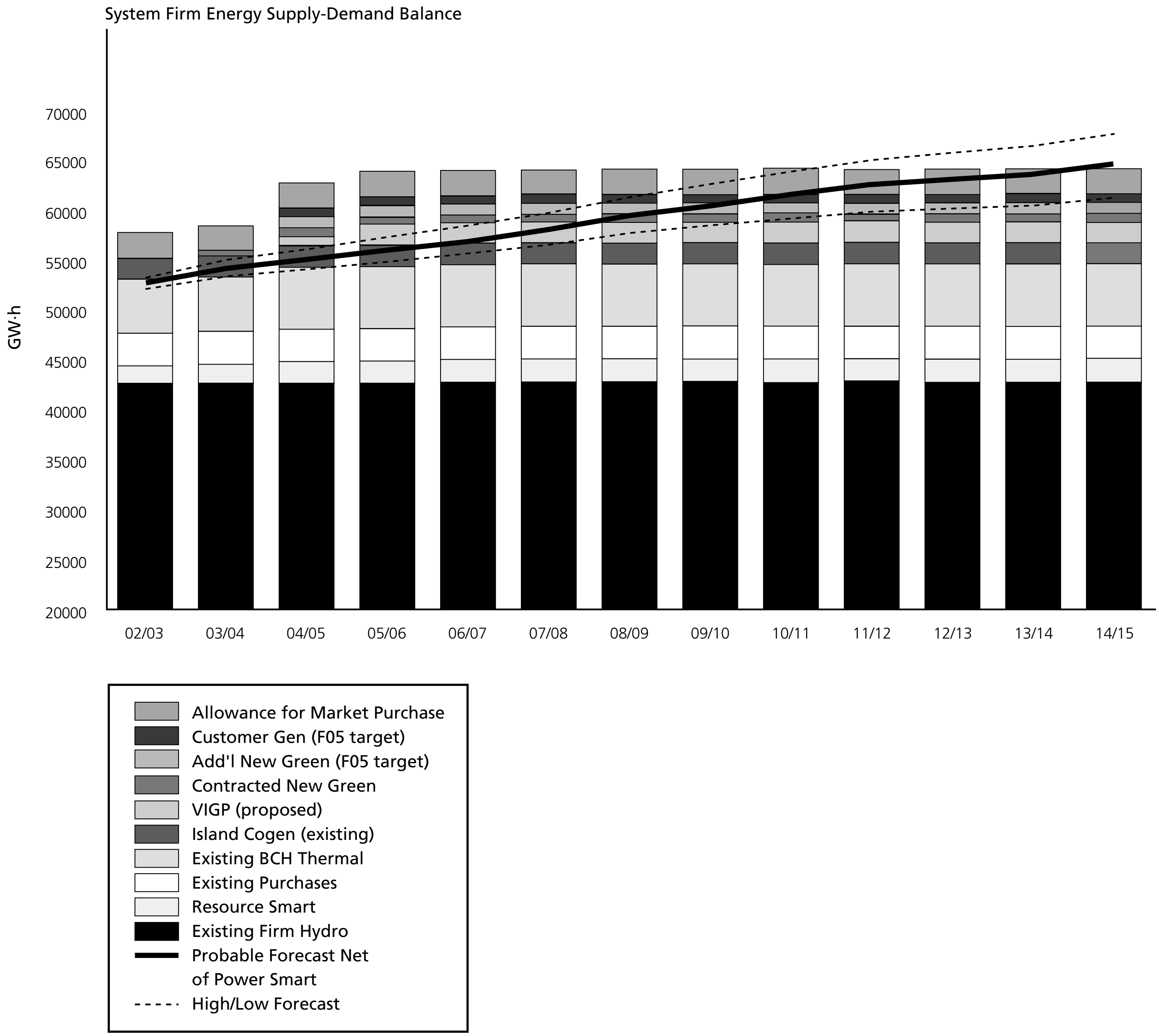
Burrard Generating Station is BC Hydro's 950 megawatt natural gas-fired generating station in Port Moody, B.C. For fiscal 01/02, Burrard generation will be approximately 2700 GW·h. Burrard generation for fiscal year 02/03 is currently forecasted to be approximately 50 GW·h, due to the current low prices of electricity on the market which makes it cheaper to import than running Burrard. However, it should be noted that Burrard Generation varies with system conditions, inflows, and the market price of potential energy imports. BC Hydro's reservoirs are currently lower than normal for this time of the year and, depending on the snowpack, the reservoir levels may have to be supplemented by Burrard generation.

As of January 2002 Burrard has one unit available for generation and two units available for synchronous condense mode operations (during which it runs to help "stabilize" the local electricity system). The other three units at Burrard are out of service for maintenance through March 31, 2002.

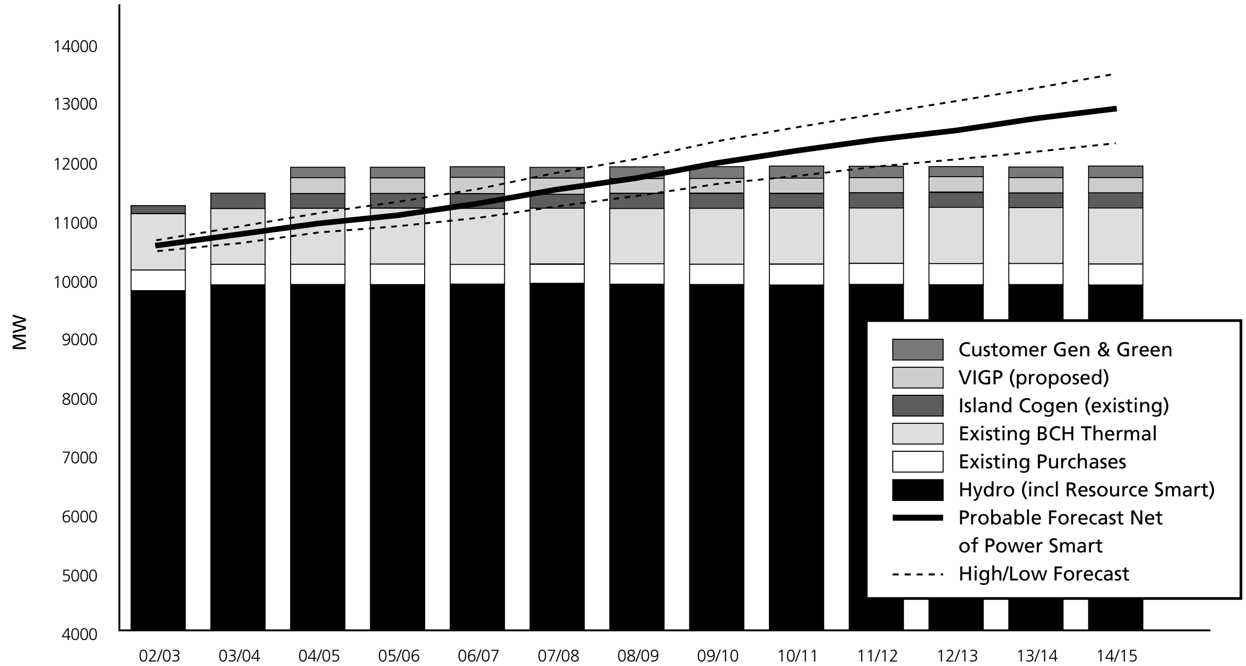
6. RESOURCES

LOAD RESOURCE BALANCE

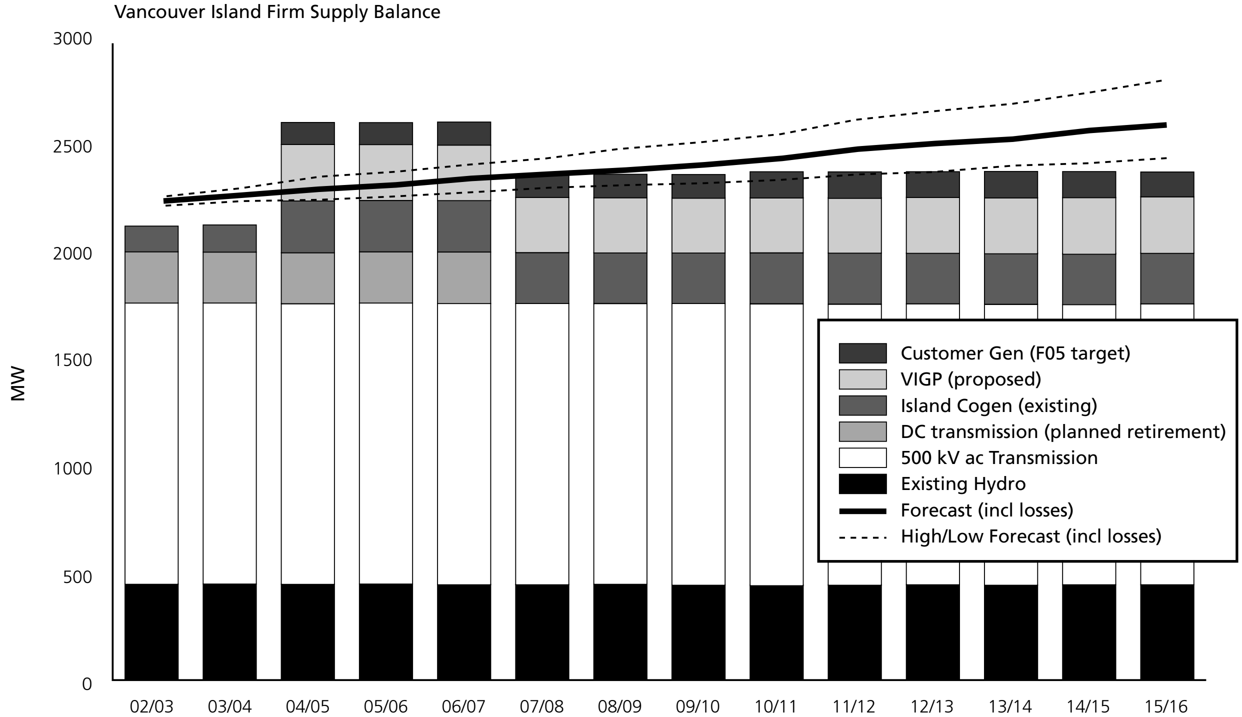
BC Hydro plans and operates its system to ensure that it meets the electricity needs of customers both now and for the future. The goal is to make sure there is enough electricity supply to meet the "load" (or electricity demand) by using a range of existing and future resources. These resources – and their relative contributions to the BC Hydro system – are shown in the charts following:



System Dependable Capacity Supply-Demand Balance



Vancouver Island Firm Supply Balance



DEMAND SIDE MANAGEMENT (DSM)

BC Hydro's Power Smart program is on track to achieve a run rate of at least 120 GW·h per year by March 31, 2002. To date, we have reached a run rate of 75 GW·h.

GREEN INDEPENDENT POWER PRODUCERS (IPPs)

BC Hydro completed its green IPP "call" and has selected a number of green IPPs. Green IPPs are categorized into those that will provide less than 40 GW·h per year and those that will produce more than 40 GW·h per year. As of December 31, 2001, four new contracts, totalling 45 GW·h per year, were completed.

CUSTOMER GENERATION PROGRAM

The Customer Generation Program has been delayed until early in the 2003 fiscal year.

UPDATE ON OTHER RESOURCES

Keogh Generating Station

Keogh is a BC Hydro generating station in Port Hardy. A decision has been made to decommission the plant. The plant is still able to run but there are no plans or need to do so because of its high running cost and low fuel level.

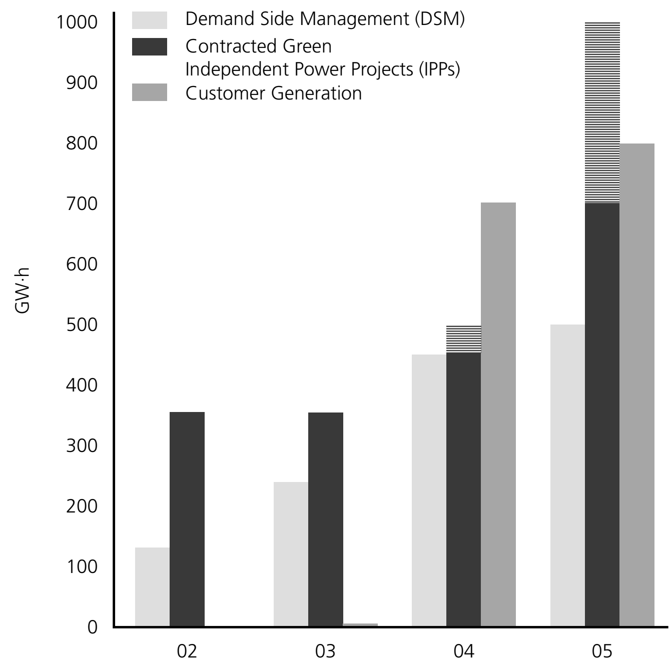
Island Cogeneration Project

The Island Cogeneration Project is a 250 megawatt (MW) combined cycle cogeneration project owned by Calpine Canada that is located near the Elk Falls pulp mill north of Campbell River. ICP continues to work towards commercial operation, something that is expected in the early spring of 2002.

Keenlyside

Keelyside is a hydroelectric project at BC Hydro's Arrow Dam that is owned by Arrow Lakes Power Corporation (a joint venture of Columbia Power Corporation and the Columbia Basin Trust). BC Hydro has a coordination agreement with Arrow Lakes Hydro and an electricity purchase agreement beginning in January 2003.

Status of Demand Side Management, Green Independent Power Projects and Customer Generation



Fort Nelson

The Fort Nelson Generating Project was completed in May 1999 as a joint venture between BC Hydro and TransAlta. It is natural gas-fired turbine with a capacity of 47 megwatts (MW). In mid 2001, TransAlta exercised its option to sell its portion of the plant to BC Hydro, which now fully owns and operates the facility. In early 2002, Powerex entered into an agreement with the Transmission Administrator of Alberta to improve stability and reliability of the Alberta transmission grid in the Rainbow Lake area that involves use of the Fort Nelson plant.

Resource Smart

The Resource Smart program was initiated in 1988 to identify and implement economic efficiency gains at existing BC Hydro facilities to provide more energy. To September 2001, 1,465 gigwatt-hours (GW·h) of restored and new energy have been brought into service. Currently there are 13 projects funded and underway, with 5 in the "Implementation Phase" (699 GW·h/year) and 8 in the "Definition Phase" (387 GW·h/year). There are additional opportunities as well, with a further 65 GW·h/year worth to be initiated in the next fiscal year.

7. SAFETY

BC Hydro makes the safety of its employees and customers a top priority. It has safety measures and targets that are tracked on a "rolling average" basis.

ROLLING 12 MONTH INJURY RATES

November 2000 through 2001

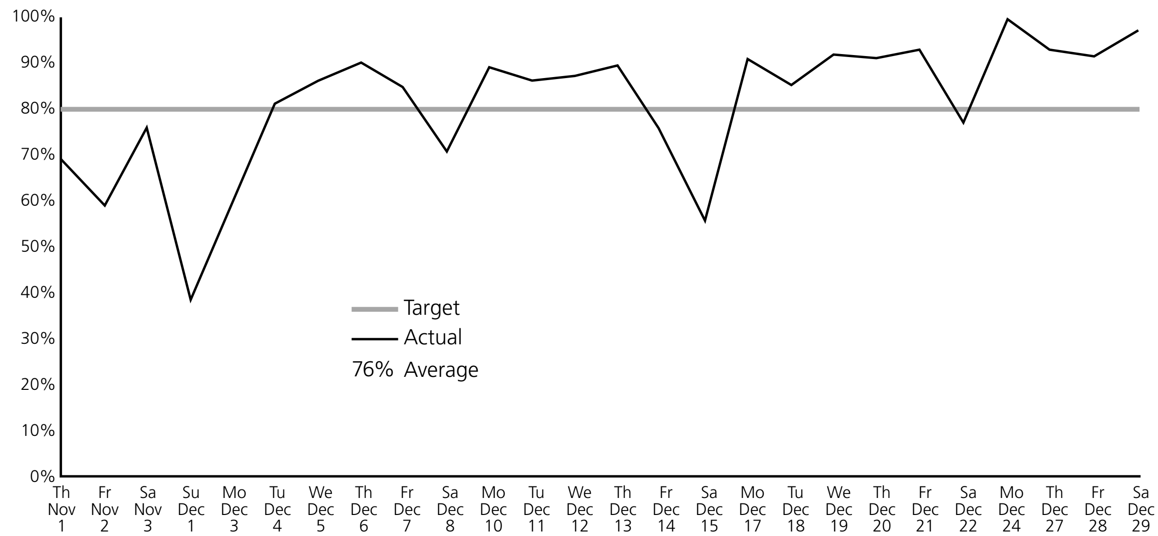
	All Injury Frequency			Disabling Injuries			Medical Aids	
	Actual	Target	Actual	Last 12 months			Last 12 months	
SBU	YTD		Last 12 months	No.	Freq.	Sev.	No.	Freq.
BC Hydro (5587 total employees)	**5.5**	**5.8**	**5.4**	**98**	**1.9**	**154.3**	**181**	**3.5**
Customer Service	7.9	8.4	9.0	21	3.6	110.4	32	5.4
T&D	8.5	8.3	8.0	64	3.0	284.1	107	5.0
Executive Opns w/ CS	6.6	5.6	7.6	21	3.0	93.7	32	4.6
Power Supply	4.2	4.8	3.8	7	0.8	52.9	26	3.0
Corporate Groups	1.4	1.1	1.4	6	0.4	49.4	16	1.0

8. CUSTOMER SERVICE

BC Hydro is committed to customer service and measures this commitment in a number of ways.

CUSTOMER SERVICES' CALL CENTRES

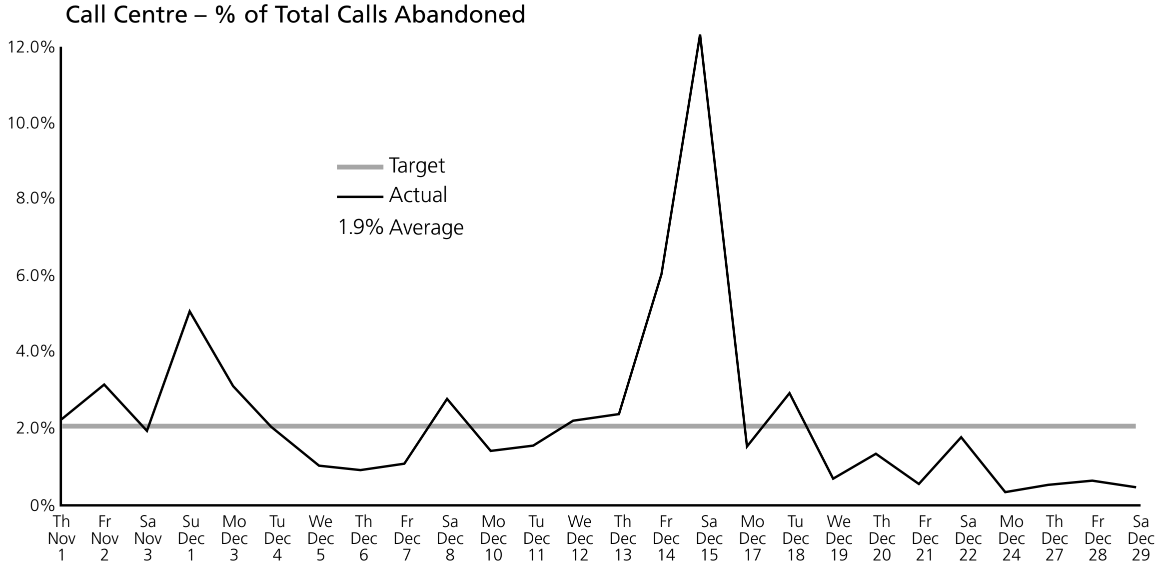
Customer Care – Service Level



Note: Measurements do not include Sundays or holidays.

Call volumes are usually highest at the beginning and end of each month (when customers move), Mondays, after long weekends, when heating costs rise (January to March), and in late summer (when people relocate to coincide with the school year). High call volumes occur during major outages, when there are bill changes or when a customer's method of daily business with BC Hydro changes.

Call Centre – % of Total Calls Abandoned



Note: Measurements do not include Sundays or holidays.

Abadonment peaks (and service level decreases) are associated with specific events such as storms or outages (as was the case for the peaks above).

9. DISTRIBUTION

RELIABILITY

BC Hydro is proud to have one of the highest reliability ratings in Canada.

12-month YTD (to Dec 31, 2001)
Average System Availability Index (ASAI)
Customer Average Interruption Duration Index (CAIDI)

Actual
- ASAI: 99.959%
- CAIDI: 2.38 hours
- ASAI (excluding Dec 14-16 major storms): 99.974%
- CAIDI (excluding Dec 14-16 major storms): 1.78 hours

Year End Target
- ASAI: 99.973%
- CAIDI: 2.15 hours

SERVICE CONNECTIONS

YTD Actuals December	11,343
YTD Plan December	13,221
Forecast Year-end	15,341
F2002 Annual Plan	16,830

10. REGULATORY UPDATE

April 1, 2001 to December 31, 2001

Fiscal year 2002 began with the consideration by the BCUC of two major applications submitted by BC Hydro. The first concerned BC Hydro's obligation to serve self-generating customers contemplating arbitrage opportunities by selling their generation output to the export market and purchasing replacement energy from BC Hydro for their industrial operations at embedded cost. Such actions could have had a potential impact to the company and its ratepayers of $400 million in lost trading revenues. After an expedited process including sponsorship of a Workshop, the BCUC rendered a decision in April relieving BC Hydro of its obligation to supply self-generating customers with embedded cost energy in excess of their historic load.

The second application, arising from a proposal by the BC Hot House Growers' Association to use cogeneration to mitigate high natural gas prices, was for approval of a wheeling rate on BC Hydro's distribution system. After an oral hearing in early May, the BCUC issued a decision on June 1 directing IPPs to pay all connection costs and setting a wheeling rate that approximated what BC Hydro had proposed during the course of the hearing.

On June 14, 2001, BC Hydro filed an application for approval of its proposed Power Smart Industrial Rate incenting large industrial customers to use up to 30% less energy than their historical consumption levels. This rate was approved by the BCUC on June 27th without any review process. Proposed amendments to this rate to reflect changed market conditions were approved by the BCUC on December 20, 2001.

Following a written hearing during the summer, the BCUC approved BC Hydro's application concerning various agreements with Centra Gas and BC Gas enabling BC Hydro to meet its obligation to transport gas supply to the ICP plant on existing pipelines until the GSX pipeline comes into service.

At present, BC Hydro does not have any applications before the BCUC for review.

A five volume application was filed on April 24, 2001 by BC Hydro's subsidiary, GSX Pipeline Canada, with the National Energy Board (NEB) for approval to construct, at an estimated cost of $132 million, and operate the Canadian portion of GSX pipeline project. Supplemental information comprising an additional three volumes was filed in October 2001. Subsequent filings have been responses to information requests from the Joint Review Panel (JRP) established to review the application.