Electric Load Forecast

2003/04 to 2023/24

Load Forecasting

Power Planning and Portfolio Management

Distribution Line of Business

BC Hydro

October 2003 Forecast, Issued December 2003

BC hydro

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Introduction

BC Hydro's Electric Load Forecast is produced annually and published in the fall. The forecast is based on several comprehensive engineering end-use and econometric models that use billed data up to March 31 of the relevant year as anchor information, combined with a wide variety of economic forecasts and inputs from internal, governmental and third party sources. The primary purpose of the electric load forecast is to provide decision-making support on the questions of "where, when, why and how much" electricity is expected to be required on the BC Hydro system.

Load forecasting is central to long-term planning, medium-term investment and short- and real-term operational and reporting activities. As such, BC Hydro's load forecasting activities centre on the production of a number of term-specific and location-specific forecasts of energy sales and peak demand requirements to meet user needs for decision-support information. A variety of related products including quarterly forecast updates, monthly variance reports, inputs for the revenue forecast, load shape analysis and small area forecasts are produced to supplement the base forecasts presented in this report.

The main users and uses of forecast products include the following:

- Generation: real-time load forecast, generating facility station dispatch and system operations;
- Rates: rate design and rate structure;
- Distribution: revenue forecasting, portfolio forecasting, distribution planning and investment and energy planning;
- Transmission: transmission planning and investment;
- British Columbia Transmission Corporation; management of transmission assets;
- Powerex: resource availability for trade;
- Corporate: consolidated net income, service plan and budget reports; and
- B.C. Utilities Commission: obligation to serve and prudence regarding expenditures and needs.

Methodology

BC Hydro's load forecast is built from the following components: the residential forecast; the commercial forecast (distribution voltage and transmission voltage), the industrial forecast (distribution voltage and transmission voltage) and the peak forecast. Key features of the methods used are shown in Table 1. These methods have been selected based on their predictive ability and to most appropriately meet the needs of the users.

Residential Forecast

The residential energy forecast is determined by forecasting the number of accounts multiplied by the rate of use. In the short term, the residential accounts forecast is based on a housing starts forecast provided by external consultants. In the medium and long terms, the forecast is based on the population forecast provided by B.C. Statistics, data from the Ministry of Management Services, regional economic forecasts and assumptions about the number of people per account.

The population in the BC Hydro service area is projected to grow from 3.82 million in 2003 to 4.32 million in 2013 and to 4.83 million by 2023. These increases represent annual compound growth rates of 1.23 per cent over the next 10 years, and 1.19 per cent over the next 20 years. The corresponding growth rates for the number of residential accounts are 1.46 per cent and 1.35 per cent, respectively. The use rate forecast is based on projections of factors such as housing mix (single family, row house, apartment, etc.), heating fuel choices (electric versus non-electric), appliance penetration rates, appliance life-span and changes in electricity demands.

Commercial Forecast

BC Hydro's commercial sector provides electricity to the buildings and non-building commercial facilities in British Columbia. The building portion of the commercial sector accounts for approximately 77 per cent of the commercial sector sales. Non-buildings account for approximately 23 per cent of the commercial sector load and includes facilities such as transportation and communication infrastructure, pipeline transport, grain elevators and utilities.

BC Hydro's commercial sector forecast is primarily an end-use or bottom-up forecast, which focuses on the demand for energy-consuming end uses to meet the requirements for commercial buildings. In its simplest form, the forecast is the product of the sector building floor stock (the floor area in square feet) and the intensity of end-use electricity demand per unit of floor stock. BC Hydro's forecast disaggregates commercial buildings in the province into 13 building types and up to 10 different end uses (space heating, water heating, ventilation, domestic hot water and so on). The non-buildings portion of the forecast is assumed to grow with factors such as GDP, employment and population.

Industrial Forecast

The industrial energy forecast includes customers receiving energy at both distribution and transmission voltage. The forecast for industrial distribution customers is based on an ordinary least squares regression of energy consumption on GDP[1]. Regression models are built separately for the agriculture, fishing, forestry, mining, construction and 15 manufacturing industries.

The Industrial transmission voltage energy forecast is built up of two segments. For the first four years, the forecast is based on projections for 130 individual transmission voltage accounts. For the next 17 years, the forecast is based on a

[1] Ordinary least squares regression is a method of choosing parameters to minimize the sum of squares of errors produced as a function of a set of variables. See Appendix 5.

maximum likelihood regression model driven by GDP, with a dummy variable for work stoppages[2].

Peak Demand

Peak demand is composed of the demand for electricity at the distribution level (i.e. residential and commercial/light industrial loads), transmission customer loads (i.e. large commercial and industrial loads) plus inter-utility sales and transmission and distribution losses. The peak forecast is prepared from a bottom-up approach, starting with distribution peak forecasts for 12 distribution planning areas and for individual substations. The distribution forecasts are driven by four primary factors[3]: economic and demographic forecasts; electric space heating forecasts; short-term forecasts of account additions; and weather-normalized peak load of each substation. The transmission forecasts are done on a customer-by-customer basis for the first four years. For the remainder of the forecast period, the industrial transmission peak forecast is based on industrial transmission energy forecasts assuming a constant load factor. Regional peak forecasts for the Lower Mainland, Northern Region, South Interior and Vancouver Island are obtained by summing the regional distribution and transmission peak forecasts using BC Hydro's regional and system peak model. Historically derived coincidence factors[4] are applied to account for load diversity (i.e. differences in the timing of distribution substation and transmission customer peaks relative to the aggregate regional peak) and losses are added.

[2] Maximum likelihood regression is a method to choose estimates for parameter values that maximize the probability that estimated parameters will represent an observed sample. See Appendix 6.

[3] The first three of these are the same drivers used in developing the energy forecasts.

[4] A coincidence factor is a ratio reflecting the relative magnitude of a region's (or customer's or group of customers') demand at the time of the system's maximum peak demand to the region's (or customer's or group of customers') maximum peak demand.

Table 1. Forecast Methodology Summary

	Activity	Use Rate	Data Sources
1. Residential Forecast	• Number of residential accounts by housing type, heating type, region	• Consumption per account based on Residential End-Use Energy Planning System (REEPS)	• Current number of accounts as base • Housing starts for short-term (first four years) • Population forecast for longer term (next 17 years) • Appliance saturation rates from Residential End Use Survey (REUS)
2. Commercial Distribution Forecast	• Floor stock by building type and by existing and new buildings	• Fuel share • Consumption per square foot based on Commercial End-Use Energy Planning System (COMMEND)	• Floor stock forecasts • End use saturation rates and intensities from Commercial End Use Survey (CEUS) with updates from Conservation Potential Review (CPR).
3. Commercial Transmission Forecast	• Number of facilities	• Current consumption adjusted for expansions, contractions, closures	• Customer billing data for commercial transmission customers (first four years) • Consumption trends extrapolated (next 17 years)
4. Industrial Distribution Forecast	• GDP (based on regression modelling)	• Current consumption	• GDP forecast
5. Industrial Transmission Forecast	• Number of facilities for first four years • GDP for next 17 years (based on regression modelling)	• Current consumption adjusted for expansions, contractions, closures	• Industrial billing data for industrial transmission customers (first four years) • GDP forecasts (next 17 years)
6. Non-Integrated Forecast	• Number of accounts	• Consumption per account (based on REEPS)	• Current number of accounts as base • Local conditions for short term (first four years) • Population forecast for longer term (next 17 years) • Appliance saturation rates from REUS
7. Peak Forecast	• Number of accounts by type • Sales to general sector • Industrial Activity and GDP	• Res. – kW/Account • Gen. – kW/kWh • Trans. – peak demand (kW or KVA) from billing data	• Previous years peak by substation, region and weather data for normalization • Customer billing data • Economic and demographic forecasts

Energy and Peak Forecast Before Power Smart

Table 2 provides a summary of historical and forecast sales and peak for selected years, before accounting for the effects of Power Smart, BC Hydro's demand-side management program.

- BC Hydro's total domestic gross sales include sales to residential, commercial and industrial customers, New Westminster and Aquila Networks Canada.
- BC Hydro's total domestic sales before Power Smart are expected to grow from 48,685 GWh in 2002/03 to 65,523 GWh in 2023/24.
- BC Hydro's total gross requirements include total domestic sales, firm exports, losses and BC Hydro's non-integrated areas.
- BC Hydro's total gross requirements before Power Smart are expected to grow from 53,339 GWh in 2002/03 to 73,191 GWh in 2023/24.
- BC Hydro's total integrated system peak (system coincident basis excluding Powerex and related losses) before Power Smart is expected to grow from 8,816 MW (9,405 MW weather normalized[5]) in 2002/03 to 13,083 MW in 2023/24.

Table 2. Energy and Peak Forecast Before Power Smart for Selected Years

	Residen-tial (GWh)	**Commer-cial (GWh)**	**Industrial (GWh)**	**Total Domestic Sales (GWh)**	**Total Gross Require-ments (GWh)**	**Total Integrated System Peak * (MW)**
1997/98	13802	12466	16339	43072	48342	8566 (8672)
2002/03	15287	13729	18596	48685	53339	8816 (9405)
2007/08	16857	15050	19139	52170	58265	10338
2012/13	18363	16578	20042	56241	62815	11175
2023/24	21743	20040	22283	65523	73191	13083
Growth Rates[6]						
5 years: 97/98 to 02/03	2.8%	1.9%	2.6%	2.5%	2.0%	0.6% (1.6%)
5 years: 02/03 to 07/08	1.3%	1.9%	0.6%	1.4%	1.8%	3.2% (1.9%)
10 years: 02/03 to 12/13	1.5%	1.9%	0.8%	1.5%	1.6%	2.4% (1.7%)
last 11 years: 12/13 to 23/24	1.5%	1.7%	1.0%	1.4%	1.4%	1.4%

* Values shown in brackets are based on weather normalized actuals

[5] Weather normalization reflects an adjustment of an actual metered load to reflect the difference between the temperature at which actual load occurred and the design temperature.
[6] Unless otherwise noted, growth rates are calculated as annual compound growth rates.

Energy and Peak Forecast After Power Smart

Table 3 provides a summary of historical and forecast sales and peak for selected years, after accounting for the effects of Power Smart.

- BC Hydro's total domestic gross sales include sales to residential, commercial and industrial customers, New Westminster and Aquila Networks Canada.
- BC Hydro's total domestic sales after Power Smart are expected to grow from 48,685 GWh in 2002/03 to 62,332 GWh in 2023/24.
- BC Hydro's total gross requirements include total domestic sales, firm exports, losses and non-integrated areas.
- BC Hydro's total gross requirements after Power Smart are expected to grow from 53,339 GWh in 2002/03 to 69,675 GWh in 2023/24.
- BC Hydro's total integrated system peak (system coincident basis excluding Powerex and related losses) after Power Smart is expected to grow from 8,816 MW (9,405 MW weather normalized) in 2003/04 to 12,568 MW in 2023/24.

Table 3. Energy and Peak Forecast After Power Smart for Selected Years

	Residen-tial (GWh)	Commer--cial (GWh)	Industrial (GWh)	Total Domestic Sales (GWh)	Total Gross Require-ments (GWh)	Total Integrated System Peak* (MW)
1997/98	13802	12466	16339	43072	48342	8566 (8672)
2002/03	15287	13729	18596	48685	53339	8816 (9405)
2007/08	16526	14467	18069	50186	56075	10017
2012/13	17716	15834	18242	53050	59298	10660
2023/24	21096	19297	20482	62332	69675	12568
Growth Rates						
5 years: 97/98 to 02/03	2.1%	1.9%	2.6%	2.5%	2.0%	0.6% (1.6%)
5 years: 02/03 to 07/08	1.6%	1.1%	-0.6%	0.6%	1.0%	2.6% (1.3%)
10 years: 02/03 to 12/13	1.5%	1.4%	-0.2%	0.9%	1.1%	1.9% (1.3%)
last 11 years: 12/13 to 23/24	1.6%	1.8%	1.1%	2.0%	1.5%	1.5%

* Values shown in brackets are based on weather normalized actuals

Sensitivity Analysis and Risks

BC Hydro's load forecast is sensitive to a number of variables including weather, economic conditions, price, etc. BC Hydro's analysis has looked specifically at the sensitivity of the load to changes in the economy (GDP) and the price of electricity. In addition, a Monte Carlo analysis has been completed to look at the sensitivity of the load to a combination five causal factors that effect the forecast.

Table 4 compares total gross requirements before Power Smart with a low GDP forecast (assuming GDP growth rates are 50 per cent of those in the reference forecast) and with a high GDP forecast (assuming that the GDP growth rates are 150 per cent of those in the reference forecast). In the low GDP case, forecast load requirements fall by 6,148 GWh in 2023/24 and with the high GDP forecast load requirements rise by 6,148 GWh in 2023/24.

Table 4. Load Sensitivity to GDP Variances for Selected Years Before Power Smart

	Total Gross Requirements (GWh) Under Low (50%) and High (150%) GDP Growth Scenarios			**Change in Total Gross Requirements** (Change in GWh and Change in Percentage)		
Case	**Low**	**Base**	**High**	**Low**	**Base**	**High**
2002/03	53,339	53,339	53,339	0 (-0.0)	None	0 (-0.0)
2007/08	56,750	58,265	59,780	-1515 (-2.6)	None	1515 (2.6)
2012/13	59,863	62,815	65,767	-2952 (-4.7)	None	2952 (4.7)
2023/24	67,043	73,191	79,339	-6148 (-8.4)	None	6148 (8.4)
Growth Rates						
5 years: 02/03 to 07/08	1.2%	1.8%	2.3%			
10 years: 02/03 to 12/13	1.2%	1.6%	2.1%			
11 years: 012/13 to 23/24	1.0%	1.4%	1.7%			

Table 5 compares total gross requirements with the base price forecast assuming that prices grow at the same rate as the CPI, or in other words that prices are constant in real terms. The rate increase scenario assumes that prices increase by six per cent in real terms in 2004/05, zero per cent in 2005/06, one percent in 2006/07, two percent in 2007/08 and are constant in real terms in subsequent years. This sensitivity analysis uses price elasticity estimates of –0.10 and –0.30 for the analysis. In the price elasticity of –0.10 case, forecast load requirements fall by 586 GWh in 2023/24 and with the elasticity of –0.30 case load requirements fall by 1,732 GWh in 2023/24.

Table 5. Load Sensitivity to Price Variances for Selected Years Before Power Smart

	Total Gross Requirements (GWh)			**Change in Total Gross Requirements (Change in GWh and Change in Percentage)**		
Case	Price = increase ε = -0.10	Price = constant	Price = increase ε = -.30	Price = Increase ε = -0.10	Price = constant	Price = Increase ε = -.30
2002/03	53,339	53,339	53,339	0 (-0.0)	None	0 (-0.0)
2007/08	57,799	58,265	56,867	-466 (-0.8)	None	-1398 (-2.4)
2012/13	62,313	62,815	61,307	-503 (-0.8)	None	-1508 (-2.4)
2023/24	72,606	73,191	71,434	-586 (-0.8)	None	-1732 (-2.4)
Growth Rates						
5 years: 02/03 to 07/08	1.6%	1.8%	1.3%			
10 years: 02/03 to 12/13	1.6%	1.6%	1.4%			
11 years: 12/13 to 23/24	1.4%	1.4%	1.4%			

A Monte Carlo sensitivity analysis was also conducted to derive an uncertainty band around the reference forecast. Five major causal factors were analyzed to determine the range of forecasts that would have an 80 per cent confidence level encompassing the reference forecast. The high, reference and low growth rates over the forecast period were projected to be about 1.9 per cent, 1.5 per cent and 1.1 per cent respectively in Total Gross Requirements, before Power Smart over the forecast period.

The main risks to the industrial forecast pertain to sales to the base metal mining and pulp and paper sectors. Highland Valley Copper has publicly stated that, based on forecasts of copper prices earlier in the year, it expects to decommission beginning in 2007/08. As well, there are other potential large-scale additions or reductions to existing industrial facilities that may or may not take place depending on the economics of existing and planned facilities. These have not been evaluated.

Response to BCUC Decisions

In its September 8, 2003, decision on the Vancouver Island Generation Project, the BCUC provided a number specific decisions relevant to the load forecast. These decisions and the actions taken in response are summarized in Table 6.

Table 6. Decisions and Summary Responses

Decision	Action
1. More appropriate to use load forecast before Power Smart rather than with Power Smart in comparing historical growth rates.	1. Both before Power Smart and with Power Smart forecasts are shown to increase transparency of the forecast in Sec. 5.
2. Provide an understanding of the methodology, input data and impacts of drivers.	2. Methodology is presented in Sec. 3, input data in Sec. 4 and impacts of drivers in Sec. 7.
3. Transparency of weather normalization, back-casting and assumptions need improvement.	3. Weather normalization is reviewed in App. 3 and App. 4, alternative forecasts in App. 5, back-casting for peak in Sec. 11 and App. 6, and assumptions in Sec. 4.
4. Include the following in future applications for major project additions: • Explanation of the selected methodology and alternatives considered; • Listing of data sources and assumptions; • Validation of the modelled outputs; • Comment on growth trends.	4. Incorporated in current forecast: • Algorithms used are explicitly stated in Sec. 3 as are a variety of regression-based alternatives in App. 5 and App. 6; • Data sources and key growth assumptions are provided in Sec. 4; • Regression modelling is used to validate the modelled outputs in App. 5 and App. 6; • Growth trends are summarized in Sec. 5.
5. Use updated numbers for Power Smart when calculating peak demand for Vancouver Island.	5. Most recent 10-Year Power Smart plan as summarized in Sec. 12 has been used for the forecast with Power Smart.
6. Adjust BC Hydro peak forecasts between 2003/04 and 2011/12 to reflect lower population growth on Vancouver Island.	6. Forecasts of numbers of accounts for all regions, including Vancouver Island, have been adjusted to reflect most recent population forecasts and peak is lower than last year's estimates for all years of the forecast period.
7. Use of -3.7 degrees Celsius based on 30-year rolling average is appropriate for Vancouver Island.	7. For this forecast, design-day temperatures of minus 6.8 degrees Celsius for the system and minus 4.4 degrees Celsius for Vancouver Island are being used. A review is underway to determine the most appropriate design-day temperatures.
8. Adjust the peak for Vancouver Island downward to adjust for anticipated rate changes.	8. Scenarios have been developed using a range of relevant elasticities from recent third party studies in high cost jurisdictions and from internal econometric estimates to provide indicative information.
9. Adjust peak for 2007/08 and 2011/12 downwards in order to account for negative variances.	9. Compared to last year's forecast, the peak for Vancouver Island has been adjusted downward by 26 MW for 2007/08 and 35 MW for 2011/12 before Power Smart.

1 Introduction

1.1. Background and Context

BC Hydro is the third largest electric utility in Canada and generates nearly 80 per cent of the electricity produced in British Columbia. Generating capacity is over 11,000 MW, with about 90 per cent of this capacity consisting of hydro-electric generation and the balance thermal generation. The remainder of the provincial electric generation capacity includes Alcan's Kemano facility, Aquila Networks Canada's plants, industry self-generation, particularly in the forest products sector, independent power producers, and small, off-grid installations, particularly in the northern part of British Columbia.

The BC Hydro Electric Load Forecast is produced annually and published in the fall. The forecast is based on comprehensive model runs that use billed data up to March 31 of the relevant year as anchor information, combined with a wide variety of forecasts and inputs from internal, governmental and third party sources. The primary purpose of the electric load forecast is to provide decision-making support on the questions of "where, when, why and how much" electricity is expected to be required on the BC Hydro system.

The forecast includes only domestic load and firm exports. The forecast does not take into account the possibility of additional sales to other utilities in the event of an excess water year generating surplus supply, nor does it reflect the net effects of the time-shifting activities that are recorded as sales activities by Powerex.

1.2. Role of Forecasting at BC Hydro

Load forecasting is central to long-term planning, medium-term investment and short- and real-term operational and reporting activities. As such, BC Hydro's load forecasting activities centre on the production of a number of term-specific and location-specific forecasts of energy sales and peak demand requirements to meet user needs for decision support information. A variety of related products including quarterly forecast updates, monthly variance reports, inputs for the revenue forecast, load shape analysis and small area forecasts are produced to supplement the base forecasts. Additionally, analytical, statistical and modelling support for a number of special and ad hoc projects, including the Conservation Potential Review, the Stepped Rates Project and the Integrated Electricity Plan, are also provided.

Forecast requirements for electric utilities are changing in response to a number of changes in the industry. These changes include:

- Increased risks as the system operates closer to capacity, increasing need for more frequent, shorter-term and risk-based forecasting at the regional, area or district level;
- Future uncertainty, resulting in more need for stress testing, and a focus on risk/sensitivity analysis;
- A shift from a previous focus on 20-year energy and peak forecasts for an integrated system, updated annually, to an increasing need for more frequent and shorter-term forecasts at the regional, area or district level;
- Focus on understanding and meeting the needs of users; and

- Increased interest on the part of the regulator and other stakeholders, reinforcing a need to ensure methods are transparent, consistent and defensible in regulatory context.

The main users and uses of forecast products include the following:

- Generation: real-time load forecast, generating facility station dispatch and system operations;
- Rates: rate design and rate structure;
- Distribution: revenue forecasting, portfolio forecasting, distribution planning and investment;
- Transmission: transmission planning and investment;
- Powerex: resource availability for trade;
- Corporate: consolidated net income, service plan and budget reports; and
- B.C. Utilities Commission: obligation to serve and prudence regarding expenditure and needs.

The key focus for the current year is to ensure that the forecast function is evolving appropriately in response to these trends.

1.3. Overview

The sections of the Electric Load Forecast are as follows.

- Section 1. Introduction
- Section 2. Regulatory Background
- Section 3. Forecast Process and Methodologies
- Section 4. Forecast Drivers, Data Sources and Assumptions
- Section 5. Reference Forecast
- Section 6. Comparison Between 2002/03 and 2003/04 Forecasts
- Section 7. Sensitivity Analysis
- Section 8. Residential Forecast
- Section 9. Commercial Forecast
- Section 10. Industrial Forecast
- Section 11. Peak Forecast
- Section 12. Power Smart and the Conservation Potential Review

2 Regulatory Background

In November 2002, the Government of British Columbia released its new energy policy, *Energy for our Future: A Plan for B.C*. Following the release of the energy policy, the *Utilities Commission Act* was amended, in part, to provide a mandate consistent with the new energy policy. In particular, the amendments clarified the regulatory role of the British Columbia Utilities Commission (BCUC) with respect to the planning requirements of utilities.

In July 2003, the BCUC issued draft resource planning guidelines. Section III (2) of the draft guidelines considers the development of gross demand forecasts (before considering the effect of demand-side management programs) and states:

> "In making a demand forecast, it is necessary to distinguish between demographic, social, economic and technological factors unaffected by utility actions, and those actions that the utility can take to influence demand, (e.g. rates, DSM programs). The latter actions should not be reflected in the utility's gross demand forecasts. More than one forecast would generally be required in order to reflect uncertainty about the future: probabilities or qualitative statements may be used to indicate that one forecast is considered to be more likely than others…"

In its decision on the Vancouver Island Generation Project of September 8, 2003, the BCUC provided a number specific decisions relevant to the load forecast. Some aspects of these decisions are still under study, while action has been taken on other aspects of these decisions. These decisions and the actions taken in response are summarized in Table 2.1.

Table 2.1. B.C. Utilities Commission Decision and Actions

Decision	Action
1. More appropriate to use load forecast before Power Smart rather than with Power Smart in comparing historical growth rates.	1. Both before Power Smart and with Power Smart forecasts are shown to increase transparency of the forecast in Sec. 5.
2. Provide an understanding of the methodology, input data and impacts of drivers.	2. Methodology is presented in Sec. 3, input data in Sec. 4 and impacts of drivers in Sec. 7.
3. Transparency of weather normalization, back-casting and assumptions need improvement.	3. Weather normalization is reviewed in App. 3 and App. 4, alternative forecasts in App. 5, back-casting for peak in Sec. 11 and App. 6, and assumptions in Sec. 4.
4. Include the following in future applications for major project additions: • Explanation of the selected methodology and alternatives considered; • Listing of data sources and assumptions; • Validation of the modelled outputs; • Comment on growth trends.	4. Incorporated in current forecast: • Algorithms used are explicitly stated in Sec. 3 as are a variety of regression-based alternatives in App. 5 and App. 6; • Data sources and key growth assumptions are provided in Sec. 4; • Regression modelling is used to validate the modelled outputs in App. 5 and App. 6; • Growth trends are summarized in Sec. 5.
5. Use updated numbers for Power Smart when calculating peak demand for Vancouver Island.	5. Most recent 10-Year Power Smart plan as summarized in Sec. 12 has been used for the forecast with Power Smart.
6. Adjust BC Hydro peak forecasts between 2003/04 and 2011/12 to reflect lower population growth on Vancouver Island.	6. Forecasts of numbers of accounts for all regions, including Vancouver Island, have been adjusted to reflect most recent population forecasts and peak is lower than last year's estimates for all years of the forecast period.
7. Use of -3.7 degrees Celsius based on 30-year rolling average is appropriate for Vancouver Island.	7. For this forecast, design-day temperatures of minus 6.8 degrees Celsius for the system and minus 4.4 degrees Celsius for Vancouver Island are being used. A review is underway to determine the most appropriate design-day temperatures.
8. Adjust the peak for Vancouver Island downward to adjust for anticipated rate changes.	8. Scenarios have been developed using a range of relevant elasticities from recent third party studies in high cost jurisdictions and from internal econometric estimates to provide indicative information.
9. Adjust peak for 2007/08 and 2011/12 downwards in order to account for negative variances.	9. Compared to last year's forecast, the peak for Vancouver Island has been adjusted downward by 26 MW for 2007/08 and 35 MW for 2011/12 before Power Smart.

3 Forecast Process and Methodologies

There are a number of key components to the load and sales forecast: the residential forecast; the commercial forecast (distribution voltage and transmission voltage); the industrial forecast (distribution voltage and transmission voltage); and the peak forecast. This section briefly reviews the key algorithms used for each of these components.

3.1. Residential Forecast Methodology

The residential energy forecast is determined by forecasting the number of accounts times rate of use based on the following expression:

(3.1) $RES = \Sigma_k \Sigma_j \Sigma_i R_{ijk} * RUR_{ijk}$,

where:

- RES is residential consumption;
- R is the number of residential accounts;
- RUR is the residential use rate;
- i indexes 20 appliances (space heating, space cooling, water heater, refrigerator, freezer, clothes washer, clothes dryer, dishwasher, range, lighting and so on);
- j indexes four housing types (single/duplex, row, apartment and other); and
- k indexes four regions (Lower Mainland, Northern Region, South Interior and Vancouver Island).

Residential accounts are forecast by extending current year trends for the first year, by using third-party forecasts of housing starts for the next three years and thereafter by applying population forecasts. Use rates are forecast from appliance saturation rates and unit energy consumption per end use (as well as their trends) to determine the average use rate by dwelling type and region and changes in these rates over time. Appliance saturation rates and unit energy consumption come from the Residential End-Use Energy Planning System model (REEPS) as updated using the Residential End Use Survey (REUS) and the Conservation Potential Review (CPR).

3.2. Commercial Forecast Methodology

The commercial distribution energy forecast for buildings (over 75 per cent of the commercial load) is determined by forecasting floor stock times rate of use based on the following expression:

(3.2) $COMDB = \Sigma_k \Sigma_j \Sigma_i STOCK_{ijk} * SHARE_{ijk} * EUI_{ijk}$

where:

- COMDB is commercial distribution voltage building consumption;

- STOCK is segment floor stock;
- SHARE is the share of stock with a given end use (these are essentially fuel shares);
- EUI is end use intensity for a given end use;
- i indexes existing and new buildings;
- j indexes 10 end uses; and
- k indexes 13 building types.

Shares of end-use stock come from the Commercial End-Use Energy Planning System (COMMEND) and are updated from the Conservation Potential Review (CPR).

The commercial distribution energy forecast for non-buildings, which includes transportation, communications and utilities (almost 25 per cent of the commercial load), is based on the following regressions:

(3.3) COMDNB = F(GDP, EMP, POP)

where:

- COMDNB is commercial distribution voltage non-building consumption;
- GDP is real provincial GDP;
- EMP is provincial employment; and
- POP is provincial population.

The commercial transmission energy forecast is based on the following expression:

(3.4) $COMT = \Sigma_j \; BASE_j{*}(1 + EXP_j)$

where:

- COMT is commercial transmission energy consumption;
- BASE is base year consumption for account j; and
- EXP is the expected impact of changes in facility size such as expansions or changes in usage rates by reference to detailed customer-by-customer projections, which are validated against other growth indices.

3.3. Industrial Forecast Methodology

The industrial distribution energy forecast is based on the following expression:

(3.5) $INDC = \Sigma_j \; \alpha_j + \beta_j{*}GDP$

where:

- INDC is industrial distribution energy;
- α_j and β_j are the regression coefficients from a time series regression for industry j of output on provincial GDP; and
- j indexes agriculture, fishing, forestry, mining, construction and 15 manufacturing industries.

The industrial transmission voltage energy forecast is built up of two segments. For the first four years, the forecast is based on the following expression:

(3.6) $INDD = \Sigma_j BASE_j*(1 + EXP_j)$

where:

- INDD is industrial energy consumption for transmission voltage customers;
- BASE is base year consumption for account j; and
- EXP is the expected impact of changes in facility capacity.

For the next 17 years, the forecast is based on the following regression model, where t refers to year t:

(3.7) $INDD_t = \alpha + \beta*GDP_t$

3.4. Peak Forecast Methodology

It is convenient to think of the peak or demand forecast as built up of four stages, each with several steps. First, substation peak in MVA non-coincident[7]; second, area peak in MVA non-coincident; third, region peak in MW on a region coincident basis; and, fourth, system peak in MW on a system coincident basis.

The substation peak forecast is first built up in several steps: (a) Distribution Planning provides actual and normalized peak loads by substation/area; (b) area substation peak forecast guidelines are developed from an econometric model; (c) Distribution Planning prepares an 11-year substation forecast; and (d) the substation and guideline peak forecast are averaged together.

The first step is analysis of last year's substation peak using the following:

(3.8) $KVA = \alpha + \beta*min$

where:

[7] Non-coincident refers to use of a coincidence factor that is a ratio reflecting the relative magnitude of a region's (or customer's or group of customers') demand at the time of the system's maximum peak demand to the region's (or customer's or group of customers') maximum peak demand.

- KVA is the weekly peak load; and
- min is the minimum temperature for the coldest day in the week.

Using the estimated regression coefficients, the weather-normalized peak is then calculated based on the design day temperature for that substation:

$$(3.9) \quad NKVA = \alpha + \beta * designmin$$

where:

- NKVA is weather-normalized peak; and
- designmin is the design temperature for the substation.

The second step is the 11-year substation guideline (econometric model):

$$(3.10) \quad SK_{it} = [\alpha_1 SFDHTG + \alpha_2 SFDNON + \alpha_3 MULTHTG + \alpha_4 MULNON + \alpha_5 U35E + \alpha_6 O35E]$$

where:

- SFDHTG is the number of single-family electrically heated homes;
- SFDNON is the number of single-family non-electrically heated homes;
- MULTHTG is the number of multi-family electrically heated homes;
- MULTNON is the number of multi-family non-electrically heated homes;
- U35E is annual energy consumption under 35 kW;
- O35E is annual energy consumption over 35kW;
- the coefficients $\alpha 1$, $\alpha 2$, $\alpha 3$, and $\alpha 4$ are kW contribution to the distribution peak per dwelling in area i, for the four dwelling types under normal temperature conditions; and
- the coefficients, $\alpha 5$ and $\alpha 6$ represent the increase in peak demand due to a one-kWh increase in the General Under 35 and Over 35 kW energy consumption.

As the third step, Distribution Planning prepares a longer-term (11-year) substation forecast, which considers the guideline forecast in addition to the trends in substation growth, load transfers between substations and large substation load additions. The fourth step is calculation of the blend/average of the long-term substation peak forecast and the peak guideline forecast for area i as:

$$(3.11) \quad PK_{it} = \Sigma_{it} SK_{it}$$

This calculation is done for 12 areas at the present time, increasing to 15 areas for next year.

The regional peak is forecast using:

$$(3.12)\quad RPK_{jt} = \Sigma_j\,[PK_{it}{*}DCF_j{*}PF_j\,{*}(1{+}DL) + TP_j{*}TCF_j{*}PF_j + WP_j{*}WCF_j]$$

where:

- DCF is the distribution peak coincidence factor;
- PF is the power factor;
- DL is the distribution loss factor;
- TP is the transmission peak;
- TCF is the transmission coincident factor;
- WP is the wholesale peak;
- WCF is the wholesale coincident factor.

Finally, system peak is the sum of coincidence-adjusted regional peaks and includes transmission losses:

$$(3.13)\quad SPK = (1 + TL){*}\Sigma_j\, RPK_{jt}\,{*}SCF_j$$

where:

- TL is the transmission loss factor; and
- SCF is the system coincidence factor for each of the four regions.

3.5. Validation

In addition to ongoing detailed analysis of inputs and outputs, there are two primary methods of model validation:

- First, regression models are built for energy and peak and the results for these models are compared to those of the reference forecast.
- Second, the current year anchor is compared to the short-term forecast for the current year and any major variances are analyzed and corrected.

4 Forecast Drivers, Data Sources and Assumptions

4.1. Forecast Drivers

Table 4.1 provides an overview of the key drivers for the reference forecast. For each forecast segment, this exhibit includes the activity variables, the use rate variables and the summary data sources.

Table 4.1. Key Forecast Drivers

	Activity	Use Rate	Data Sources
1. Residential Forecast	• Number of residential accounts by housing type, heating type, region	• Consumption per account based on Residential End-Use Energy Planning System (REEPS)	• Current number of accounts as base • Housing starts for short-term (first four years) • Population forecast for longer term (next 17 years) • Appliance saturation rates from Residential End Use Survey (REUS)
2. Commercial Distribution Forecast	• Floor stock by building type and by existing and new buildings	• Fuel share • Consumption per square foot based on Commercial End-Use Energy Planning System (COMMEND)	• Floor stock forecasts • End use saturation rates and intensities from Commercial End Use Survey (CEUS) with updates from Conservation Potential Review (CPR).
3. Commercial Transmission Forecast	• Number of facilities	• Current consumption adjusted for expansions, contractions, closures	• Customer billing data for commercial transmission customers (first four years) • Consumption trends extrapolated (next 17 years)
4. Industrial Distribution Forecast	• GDP (based on regression modelling)	• Current consumption	• GDP forecast
5. Industrial Transmission Forecast	• Number of facilities for first four years • GDP for next 17 years (based on regression modelling)	• Current consumption adjusted for expansions, contractions, closures	• Industrial billing data for industrial transmission customers (first four years) • GDP forecasts (next 17 years)
6. Non-Integrated Forecast	• Number of accounts	• Consumption per account (based on REEPS)	• Current number of accounts as base • Local conditions for short term (first four years) • Population forecast for longer term (next 17 years) • Appliance saturation rates from REUS
7. Peak Forecast	• Number of accounts by type • Sales to general sector • Industrial Activity and GDP	• Res. – kW/Account • Gen. – kW/kWh • Trans. – peak demand (kW or KVA) from billing data	• Previous years peak by substation, region and weather data for normalization • Customer billing data • Economic and demographic forecasts

4.2. Growth Rates

Table 4.2 provides a summary of assumptions on key growth rates for the reference forecast. Growth rates are shown for population, real GDP and employment. Housing starts are shown in thousands. Unless otherwise noted, all growth rates are calculated as average annual compound growth rates.

For GDP, three sources have been used to generate the weighted average shown in the table. The average is heavily weighted to the BC Ministry of Finance Forecast in the first four years and then to external consultants (RA Malatest) and DOE values further out (see Table 4.3). Actual data is shown for 1998 to 2002 and forecast data is shown for 2003 to 2023. Two features of this data are worth noting.

- First, based on provincial forecasts, modest rates of population growth are assumed for the forecast period, which acts as a constraint on growth of residential and commercial energy consumption.
- Second, although the forecast assumes reasonably smooth future growth in GDP, the B.C. economy in recent years has been subject to significant external shocks that have led to quite uneven growth rates. This is a significant source of uncertainty for the load forecast.

Table 4.2. Growth Assumptions

	Pop (%)	Real GDP Weighted (%)	Housing Starts (‘000)	Employment (%)
Actual				
1998	0.9	1.3	19.9	0.1
1999	0.8	2.8	16.3	1.9
2000	0.8	4.3	14.4	2.2
2001	0.9	-0.2	17.2	-0.3
2002	1.1	1.8	21.6	1.6
Forecast				
2003	0.9	1.5	28.1	2.7
2004	1.1	2.6	30.4	2.2
2005	1.2	3.0	32.9	2.2
2006	1.2	2.9	35.5	2.1
2007	1.2	2.9	38.0	2.1
2008	1.2	2.7	36.7	2.0
2009	1.3	2.6	35.5	1.8
2010	1.3	2.6	34.2	1.7
2011	1.3	2.4	32.9	1.8
2012	1.3	2.3	31.7	1.5
2013	1.2	2.4	29.0	1.8
2014	1.2	2.4	29.0	1.8
2015	1.2	2.4	29.0	1.8
2016	1.2	2.4	29.0	1.8
2017	1.2	2.4	29.0	1.8
2018	1.1	2.3	28.0	1.7
2019	1.1	2.3	28.0	1.7
2020	1.1	2.3	28.0	1.7
2021	1.1	2.3	28.0	1.7
2022	1.1	2.3	28.0	1.7
2023	1.1	2.3	28.0	1.7

Notes: See Data Sources, Table 4.3.

Information on the sources and the uses of the growth assumptions is shown in Table 4.3. For each key driving variable, this exhibit shows those applications where the variable is used, the time period(s) for which the variable is used and the detailed data sources.

4.3. Data Sources

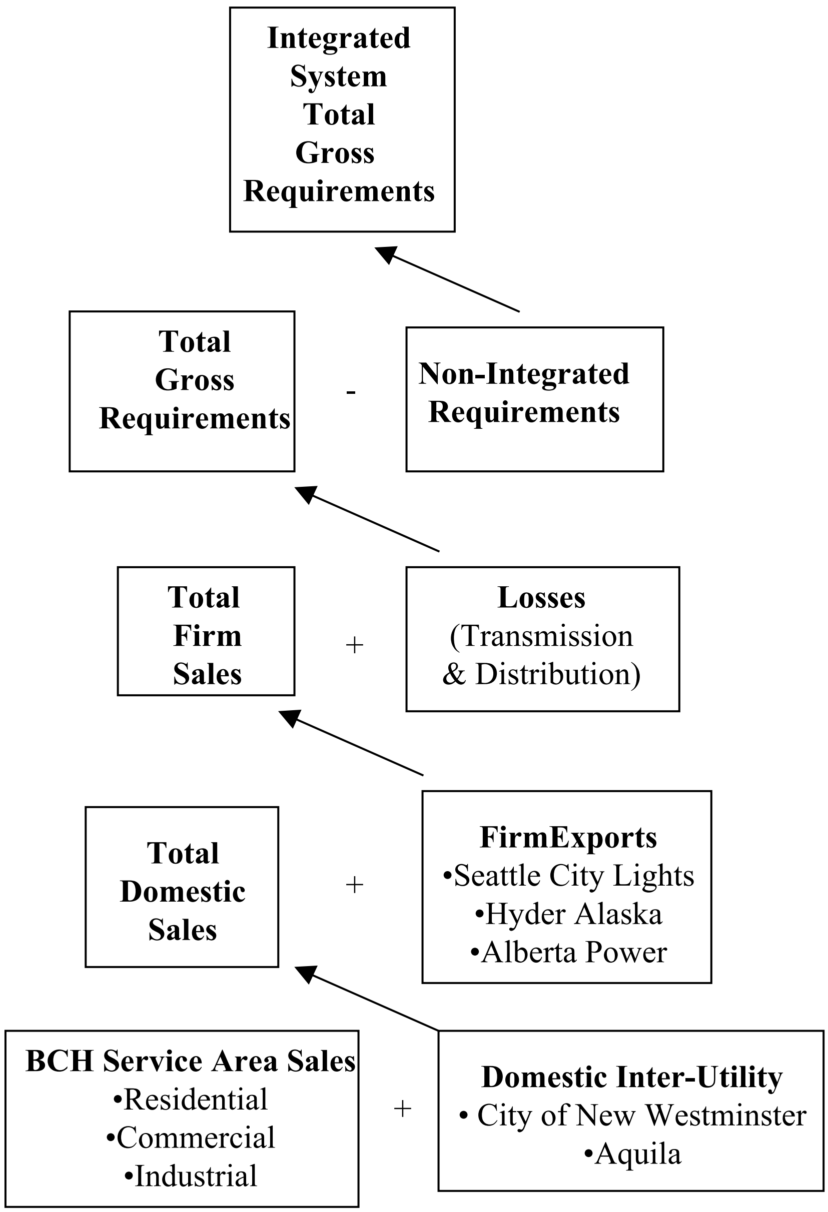
Table 4.3. Data Sources and Uses for Growth Assumptions

Variable	Application	Period	Source
Population	• Residential energy forecast • Commercial non-building energy forecast • Number of residential accounts for peak	• 2007-2023 • 2003-2023 • 2003-2006	• B.C. Statistics, B.C. Population Forecast, June 2003 • B.C. Statistics, B.C. Population Forecast, June 2003 • B.C. Statistics, B.C. Population Forecast, June 2003
GDP (Gov)	• Industrial energy forecast	• 2003-2007	• B.C. Ministry of Finance, First Quarterly Report 2003/04, September 2003
GDP (External Consultant)	• Industrial energy forecast	• 2003-2023	• R A Malatest, July 2003
GDP (DOE)	• Industrial energy forecast	• 2008-2023	• B.C. share based on Canadian GDP forecast, USA Department of Energy, Annual Energy Outlook 2003
GDP (weighted)	• Industrial energy forecast	• 2003-2023	• Weighted average of Malatest and government sources
Housing Starts	• Residential energy forecast	• 2003-2006	• R A Malatest, July 2003
Employment	• Number of general under 35 kW accounts for peak • Number of general over 35 kW accounts for peak	• 2003-2023 • 2003-2023	• B.C. Ministry of Finance, First Quarterly Report 2003/04, September 2003 • B.C. Ministry of Finance, First Quarterly Report 2003/04, September 2003

5 Reference Forecast

Figure 5.1summarizes the aggregation of the different elements of BC Hydro's reference energy forecast.

Figure 5.1. BC Hydro Load Forecast Build-up



5.1. Reference Forecast Before Power Smart

Table 5.1 provides a summary of historical sales and peaks and the reference forecast before Power Smart, that is, before considering the effects of BC Hydro's demand-side management program (See Sections 8, 9 and10 for the individual sector forecasts). BC Hydro's total domestic sales before Power Smart include residential, commercial and industrial sales for the BC Hydro service area as well as sales to New Westminster and Aquila Networks Canada. BC Hydro's total domestic sales before Power Smart are expected to grow from 48,685 GWh in 2002/03 to 65,523 GWh in 2023/24. BC Hydro's total gross requirements include total domestic sales, firm exports, losses and non-integrated areas. BC Hydro's total gross requirements before Power Smart are expected to grow from 53,339 GWh in 2002/03 to 73,191 GWh in 2023/24.

Growth rates of sales vary significantly by sector but within a given sector are fairly consistent over time. For the residential sector, the growth rates of sales before Power Smart are 2.0 per cent for the five years from 2002/03 to 2007/08; 1.9 per cent for the 10 years from 2002/03 to 2012/13; and 1.5 per cent in the last 11 years of the forecast 2012/13 to 2023/24.

For the commercial sector, the growth rates of sales before Power Smart are 1.9 per cent for the five years from 2002/03 to 2007/08; 1.9 per cent for the 10 years from 2002/03 to 2012/13; and 1.7 per cent in the last 11 years of the forecast, 2012/13 to 2023/24.

For the industrial sector, the growth rates of sales before Power Smart are 0.6 per cent for the five years from 2002/03 to 2007/08; 0.8 per cent for the 10 years from 2002/03 to 2012/13; and 1.0 per cent in the last 11 years of the forecast, 2012/13 to 2023/24.

For total gross requirements, the growth rates of sales before Power Smart are 1.8 per cent for the five years from 2002/03 to 2007/08; 1.6 per cent for the 10 years from 2002/03 to 2012/13; and 1.4 per cent in the last 11 years of the forecast, 2012/13 to 2023/24.

BC Hydro's total integrated system peak (system coincident basis excluding Powerex and related losses) before Power Smart is expected to grow from 8,816 MW (9,405 MW weather normalized) in 2002/03 to 13,083 MW in 2023/24. The five-year growth rate from 2002/03 to 2007/08 is 3.2 per cent (1.9 per cent weather normalized). The 10-year growth rate from 2002/03 to 2012/13 is 2.4 per cent (1.7 per cent weather normalized). The 11-year growth rate from 2012/13 to 2023/04 is 1.4 per cent.

Table A7.1 in Appendix 7 provides additional details of the 2003 forecast before Power Smart.

Table 5.1. Reference Forecast Before Power Smart

	Residential (GWh)	**Commercial (GWh)**	**Industrial (GWh)**	**Total Domestic Sales (GWh)**	**Total Gross Requirements (GWh)**	**Total Integrated Sys. Peak* (MW)**
Actual (not weather-normalized)						
1997/98	13802	12466	16339	43072	48342	8566 (8672)
1998/99	13972	12814	18077	45513	50897	9026
1999/00	14572	13176	17890	46376	51534	8646
2000/01	14573	13654	18679	47891	52978	9319
2001/02	15090	13583	17739	47473	52567	9003
2002/03	15287	13729	18596	48685	53339	8816 (9405)
Forecast (Residential energy and System Peak forecasts assume "normal weather")						
2003/04	15688	13908	18409	49113	54844	9662
2004/05	15955	14120	18679	49844	55657	9823
2005/06	16244	14403	18806	50563	56463	9989
2006/07	16544	14723	18913	51284	57273	10148
2007/08	16857	15050	19139	52170	58265	10338
2008/09	17134	15346	19323	52988	59176	10514
2009/10	17431	15658	19505	53796	60080	10693
2010/11	17737	15985	19692	54635	61018	10853
2011/12	18058	16281	19868	55446	61926	11016
2012/13	18363	16578	20042	56241	62815	11175
2013/14	18671	16844	20227	57020	63687	11330
2014/15	18982	17143	20417	57841	64604	11506
2015/16	19293	17449	20611	58673	65535	11681
2016/17	19604	17722	20810	59471	66427	11856
2017/18	19914	18015	21013	60295	67347	12031
2018/19	20223	18320	21213	61125	68275	12207
2019/20	20529	18642	21417	61974	69226	12382
2020/21	20835	18995	21627	62861	70215	12557
2021/22	21139	19319	21840	63719	71173	12732
2022/23	21441	19673	22059	64611	72171	12908
2023/24	21743	20040	22283	65523	73191	13083
Growth Rates						
5 years: 97/98 to 02/03	2.1%	1.9%	2.6%	2.5%	2.0%	0.6% (1.6%)
5 years: 02/03 to 07/08	2.0%	1.9%	0.6%	1.4%	1.8%	3.2% (1.9%)
10 years: 02/03 to 12/13	1.9%	1.9%	0.8%	1.5%	1.6%	2.4% (1.7%)
last 11 years: 12/13 to 23/24	1.5%	1.7%	1.0%	1.4%	1.4%	1.4%

* Values shown in brackets are based on weather normalized actuals

5.2. Reference Forecast With Power Smart

Table 5.2 provides a summary of historical sales and peaks and the reference forecast with Power Smart, that is, including the effects of BC Hydro's demand-side management program. BC Hydro's total domestic sales with Power Smart include residential, commercial and industrial sales for the BC Hydro service area as well as sales to New Westminster and Aquila Networks Canada. BC Hydro's total domestic sales with Power Smart are expected to grow from 48,685 GWh in 2002/03 to 62,332 GWh in 2023/24. BC Hydro's total gross requirements include total domestic sales, firm exports and losses. BC Hydro's total gross requirements with Power Smart are expected to grow from 53,339 GWh in 2002/03 to 69,675 GWh in 2023/24.

It should be noted that new Power Smart activities reflect the current 10-year Power Smart Plan and not any possible Power Smart activities after this period

Again, growth rates of sales vary significantly by sector but within a given sector are fairly consistent over time. For the residential sector, the growth rates of sales with Power Smart are 1.6 per cent for the five years from 2002/03 to 2007/08; 1.5 per cent for the 10 years from 2002/03 to 2012/13; and 1.6 per cent for the 11 years from 2012/13 to 2023/24.

For the commercial sector, the growth rates of sales with Power Smart are 1.1 per cent for the five years from 2002/03 to 2007/08; 1.4 per cent for the 10 years from 2002/03 to 2012/13; and 1.8 per cent for the 11 years from 2012/13 to 2023/24.

For the industrial sector, the growth rates of sales with Power Smart are –0.6 per cent for the five years from 2002/03 to 2007/08; –0.2 per cent for the 10 years from 2002/03 to 2012/13; and 1.1 per cent for the 11 years from 2012/13 to 2023/24.

For total gross requirements, the growth rates of sales with Power Smart are 1.0 per cent for the five years from 2002/03 to 2007/08; 1.1 per cent for the 10 years from 2002/03 to 2012/13; and 1.5 per cent for the 11 years from 2012/13 to 2023/24.

BC Hydro's total integrated system peak (system coincident basis excluding Powerex and related losses) with Power Smart is expected to grow from 8,816 MW (9,405 MW weather normalized) in 2002/03 to 12,568 MW in 2023/24. The five-year growth rate from 2002/03 to 2007/08 is 2.6 per cent (1.3 per cent weather normalized). The 10-year growth rate from 2002/03 to 2012/13 is 1.9 per cent (1.3 per cent weather normalized). The 11-year growth rate from 2012/13 to 2023/04 is 1.5 per cent.

Essentially, compared to last year the peak forecast is reduced in the short-term to reflect current economic conditions and revised forecast drivers. On an integrated system total basis, this year's forecast including Power Smart is 43 MW lower for the winter of 2003/04, 131 MW lower for 2004/05, 119 MW lower for 2005/06, 167 MW lower for 2006/07 and in the range of 200 to 300 MW lower for the period from 2007/08 to 2011/12.

The following points are worth noting with respect to the peak forecast:

- The distribution peak forecast was revised downward to reflect changes in the 2003 population and employment forecasts compared to 2002. A gradual recovery is projected to occur over the next five years, resulting in higher growth over the longer term, from the base year 2002/03.

- The transmission peak forecast has been updated to reflect restructuring occurring among B.C.'s resource-based industries. The forecast also includes the closing of a large copper mine in 2007/08 in the South Interior.
- The forecast is based on design temperatures of –6.8 degrees Celsius for the system and –4.4 degrees Celsius for Vancouver Island. In light of the BCUC Decision on VIGP, a review of the design temperatures is underway.
- Capacity savings estimates related to Power Smart impacts for each region and the system were provided by Power Smart.

Table A7.2 in Appendix 7 provides additional details of the 2003 forecast with Power Smart.

Table 5.2. Reference Forecast With Power Smart

	Residen-tial (GWh)	**Commer-cial (GWh)**	**Industrial (GWh)**	**Total Domestic Sales (GWh)**	**Total Gross Require-ments (GWh)**	**Total Integrated Sys. Peak* (MW)**
Actual (not weather normalized)						
1997/98	13802	12466	16339	43072	48342	8566 (8672)
1998/99	13972	12814	18077	45513	50897	9026
1999/00	14572	13176	17890	46376	51534	8646
2000/01	14573	13654	18579	47891	52978	9319
2001/02	15090	13583	17739	47473	52567	9003
2002/03	15287	13729	18596	48685	53339	8816 (9405)
Forecast (Residential and System Peak forecasts assume "normal weather")						
2003/04	15638	13843	18268	48858	54563	9620
2004/05	15816	13870	18227	49003	54728	9687
2005/06	16042	14011	18154	49317	55086	9787
2006/07	16280	14208	18044	49637	55454	9881
2007/08	16526	14467	18069	50186	56075	10017
2008/09	16730	14718	18057	50690	56641	10144
2009/10	16950	14993	18044	51190	57207	10274
2010/11	17171	15280	18052	51724	57810	10385
2011/12	17410	15537	18068	52254	58410	10502
2012/13	17716	15834	18242	53050	59298	10660
2013/14	18023	16101	18426	53828	60169	10816
2014/15	18334	16400	18616	54650	61088	10991
2015/16	18646	16706	18809	55480	62018	11166
2016/17	18957	16979	19008	56280	62910	11342
2017/18	19267	17273	19213	57105	63832	11517
2018/19	19576	17577	19412	57934	64758	11692
2019/20	19882	17900	19615	58783	65709	11867
2020/21	20188	18253	19826	59670	66699	12043
2021/22	20492	18576	20039	60528	67657	12218
2022/23	20794	18930	20259	61422	68656	12393
2023/24	21096	19297	20482	62332	69675	12568
Growth Rates						
5 years: 97/98 to 02/03	2.1%	1.9%	2.6%	2.5%	2.0%	0.6% (1.6%)
5 years: 02/03 to 07/08	1.6%	1.1%	-0.6%	0.6%	1.0%	2.6% (1.3%)
10 years: 02/03 to 12/13	1.5%	1.4%	-0.2%	0.9%	1.1%	1.9% (1.3%)
last 11 years: 12/13 to 23/24	1.6%	1.8%	1.1%	1.5%	1.5%	1.5%

* Values shown in brackets are based on weather normalized actuals

Comparing the growth rates in Tables 5.1 and 5.2 for energy and for peak both before and with Power Smart, note that:

- First, energy before Power Smart tracks the key economic drivers real GDP and employment fairly closely. This largely reflects the importance of real

GDP and employment as forecast drivers and their strong historical relationships to energy consumption.

- Second, applying the full Power Smart targets reduces energy growth substantially for the first 11 years, but has less impact over latter part of the forecast period. This reflects the absence of new planned/approved Power Smart activity after the current 10-year Power Smart plan.
- Third, peak is growing more quickly than energy. This is due to three main factors: use of 2002/03 as the base year, when 2002/03 had a low peak compared to adjacent years; increase in the relative share of residential energy compared to industrial energy; and increase in the relative share of commercial energy compared to industrial energy

Figures 5.2 and 5.3 present the reference forecast before and with Power Smart for total gross requirements and peak.

Figure 5.2. Reference Forecast Before and With Power Smart – Total Gross Requirements (GWh)

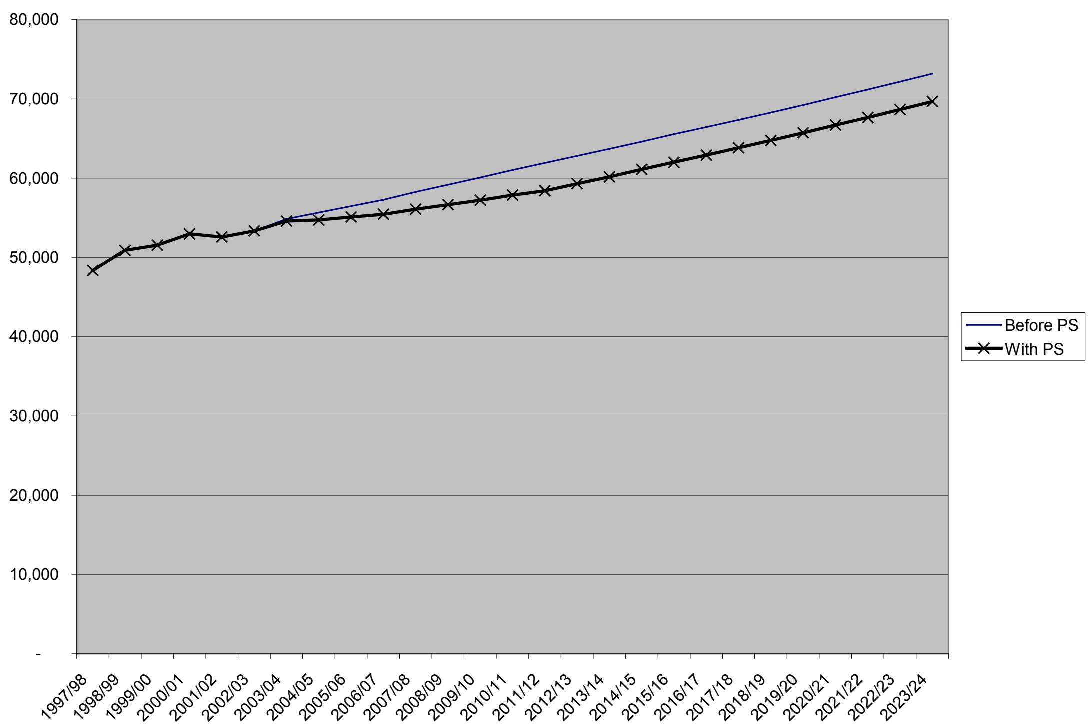
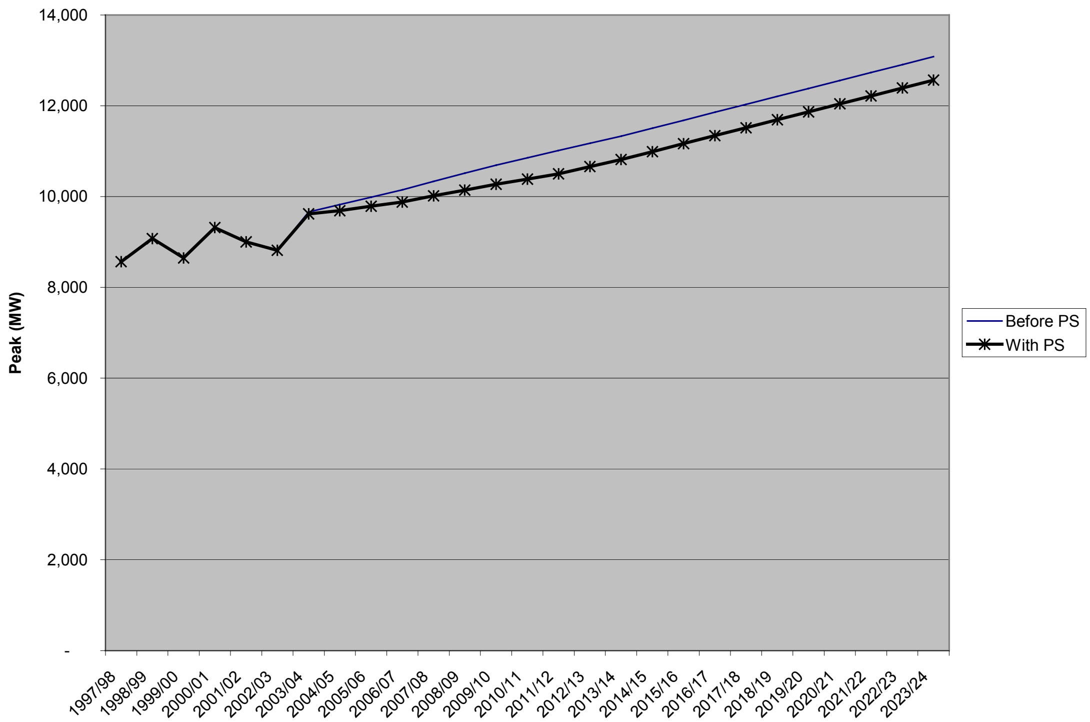


Figure 5.3. Reference Forecast Before and With Power Smart – Integrated System Peak



6 Comparison Between 2002/03 and 2003/04 Forecasts

This section compares 2003 energy forecast with the 2002 forecast and discusses the differences between them.

6.1. Total Gross Requirements

Table 6.1 compares total gross requirements for the October 2003 reference forecast including the effects of Power Smart with the December 2002 forecast including Power Smart. For all years except 2003/04, the 2003 forecast is lower than the December 2002 forecast. For 2003/04, the 2003 forecast is above the 2002 forecast by 467 GWh. Much of the increase in 2003/04 is a result of considerably higher than expected sales to the industrial sector in 2002/03, which increased the anchor point for the forecast (see Section 6.4). For 2012/13, the 2003 forecast is 853 GWh below the 2002 forecast, while for 2022/23 the 2003 forecast is 1,393 GWh below the 2002 forecast. The difference in 2001/02 is a result of the final total generation data for 2001/02 being received after the 2002 forecast was completed.

Table 6.1. Comparison of Reference Energy Forecasts With Power Smart: Gross System Requirements

	October 2003 Forecast (GWh)	December 2002 Forecast (GWh)	October 2003 minus December 2002 (GWh)
1998/99	50897	50897	-
1999/00	51534	51354	-
2000/01	52978	52978	-
2001/02	52567	52582	-15
2002/03	53339	53804	-465
2003/04	54563	54096	467
2004/05	54728	54916	-188
2005/06	55086	55269	-183
2006/07	55454	55872	-418
2007/08	56075	56678	-603
2008/09	56641	57600	-959
2009/10	57207	58685	-1478
2010/11	57810	59376	-1566
2011/12	58410	59852	-1442
2012/13	59298	60151	-853
2013/14	60169	60609	-440
2014/15	61088	61635	-547
2015/16	62018	62685	-667
2016/17	62910	63714	-804
2017/18	63832	64776	-944
2018/19	64758	65802	-1044
2019/20	65709	66892	-1183
2020/21	66699	67958	-1259
2021/22	67657	69009	-1352
2022/23	68656	70049	-1393
2023/24	69675	-	-

6.2. Residential Sales

Table 6.2 compares the October 2003 residential reference forecast including Power Smart with the December 2002 forecast including Power Smart. For residential sales, the 2002 forecast is above the 2003 forecast by 227 GWh for 2003/04, above the 2002 forecast by 266 GWh in 2012/13 and below the 2002 forecast by 155 GWh in 2022/23. The main reason for the increase in forecast residential sales for most of the forecast period is that the residential use rate has been increasing due to the increased saturation of secondary appliances, as demonstrated by billing data analysis. A second reason driving growth is the increase in the forecast number of residential accounts due to forecasts of strong housing starts for the first four years. Beyond this period, account growth levels off and is less strong than was assumed last year as a result of lower population forecast growth, bringing down forecast residential sales.

Table 6.2. Comparison of Reference Energy Forecasts With Power Smart: Residential Sales

	October 2003 Forecast (GWh)	December 2002 Forecast (GWh)	October 2003 minus December 2002 (GWh)
1998/99	13972	13972	-
1999/00	14572	14572	-
2000/01	14573	14573	-
2001/02	15090	15090	-
2002/03	15287	15358	-71
2003/04	15638	15411	227
2004/05	15816	15572	244
2005/06	16042	15751	291
2006/07	16280	15993	347
2007/08	16526	16134	392
2008/09	16730	16370	360
2009/10	16950	16610	340
2010/11	17171	16859	312
2011/12	17410	17132	278
2012/13	17716	17450	266
2013/14	18023	17794	229
2014/15	18334	18143	191
2015/16	18646	18491	155
2016/17	18957	18842	115
2017/18	19267	19191	76
2018/19	19576	19536	40
2019/20	19882	19887	-5
2020/21	20188	20243	-55
2021/22	20492	20594	-102
2022/23	20794	20949	-155
2023/24	21096	-	-

6.3. Commercial Sales

Table 6.3 compares the October 2003 commercial reference forecast including Power Smart with the December 2002 forecast including Power Smart. For commercial sales, the 2003 forecast is below the 2002 forecast by 200 GWh for 2003/04, below the 2002 forecast by 1,233 GWh in 2012/13 and below the 2002 forecast by 1,664 GWh in 2022/23. A number of factors contribute to these changes.

- A slower than expected economic recovery has resulted in a lower starting point for the forecast than was anticipated in the 2002 forecast. For example, actual sales in 2002/03 were 73 GWh below what was forecast and by the end of 2003/04 the difference is expected to be 200 GWh.
- An additional 575 GWh of Power Smart savings have been allocated to the commercial sector by 2012/13.

- Over the medium and long term, declining growth rates for several of the macro economic indicators including employment and GDP have contributed to lower long-term growth rates for the commercial sector.

Table 6.3. Comparison of Reference Energy Forecasts With Power Smart: Commercial Sales

	October 2003 Forecast (GWh)	December 2002 Forecast (GWh)	October 2003 minus December 2002 (GWh)
1998/99	12814	12814	-
1999/00	13176	13176	-
2000/01	13654	13654	-
2001/02	13583	13583	-
2002/03	13729	13802	-73
2003/04	13843	14043	-200
2004/05	13870	14376	-506
2005/06	14011	14733	-722
2006/07	14208	15045	-837
2007/08	14467	15379	-912
2008/09	14718	15685	-967
2009/10	14993	16031	-1038
2010/11	15280	16375	-1095
2011/12	15537	16734	-1197
2012/13	15834	17067	-1233
2013/14	16101	17381	-1280
2014/15	16400	17724	-1324
2015/16	16706	18087	-1381
2016/17	16979	18422	-1443
2017/18	17273	18781	-1508
2018/19	17577	19119	-1542
2019/20	17900	19497	-1597
2020/21	18253	19873	-1620
2021/22	18576	20232	-1656
2022/23	18930	20594	-1664
2023/24	19297	-	-

6.4 Industrial Sales

Table 6.4 compares the October 2003 industrial reference forecast including Power Smart with the December 2002 forecast including Power Smart. For industrial sales, the 2003 forecast is above the 2002 forecast by 388 GWh for 2003/04, above the 2002 forecast by 223 GWh in 2012/13 and above the 2002 forecast by 648 GWh in 2022/23. For the current year, the 2003 forecast is higher than the 2002 forecast because 2003/04 has been re-anchored to the 2002/03 results, which were 634 GWh above the 2002 forecast.

It should be noted that for the December 2003 forecast there is a change in the methodology for forecasting industrial transmission account loads that reduces bias in forecasting specific accounts and provides greater transparency to the forecast. In the 2002 forecast, estimates of individual transmission accounts were used for the first half of the forecast period with these implied growth rates projected for the second half of the forecast period. For the 2003 forecast, estimates of individual transmission accounts were used for only the first four years of the forecast with an econometric model based on GDP used for the remaining 17 years.

This change acknowledges that the value of specific account information and key account market intelligence diminishes over time in terms of providing relevant information about account growth.

Table 6.4. Comparison of Reference Energy Forecasts With Power Smart: Industrial Sales

	October 2003 Forecast (GWh)	December 2002 Forecast (GWh)	October 2003 minus December 2002 (GWh)
1998/99	18077	18077	-
1999/00	17890	17890	-
2000/01	18579	18579	-
2001/02	17739	17739	-
2002/03	18596	17962	634
2003/04	18268	17880	388
2004/05	18227	18086	142
2005/06	18154	17793	361
2006/07	18044	17823	221
2007/08	18069	18030	39
2008/09	18057	18301	-244
2009/10	18044	18676	-632
2010/11	18052	18679	-627
2011/12	18068	18440	-372
2012/13	18242	18019	223
2013/14	18426	17733	693
2014/15	18616	17937	679
2015/16	18809	18141	668
2016/17	19008	18355	653
2017/18	19213	18574	639
2018/19	19412	18786	626
2019/20	19615	19007	608
2020/21	19826	19206	620
2021/22	20039	19415	624
2022/23	20259	19611	648
2023/24	20482	-	-

6.5. Peak Sales

Compared to 2002, the peak forecast is reduced in the short term to reflect current economic conditions and revised forecast drivers. On an integrated system total basis, the 2003 forecast including Power Smart (9,620 MW) is 43 MW lower for the winter of 2003/04; 131 MW lower for 2004/05; 119 MW lower for 2005/06; 167 MW lower for 2006/07; and in the range of 200 to 300 MW lower for the period from 2007/08 to 20011/12.

The following points are worth noting with respect to the peak forecast:

- The distribution peak forecast was revised downward for 2003/04 to reflect changes in the 2003 population and employment forecasts compared to 2002. A gradual recovery is projected to occur over the next five years, resulting in higher growth over the longer term, using 2002/03 as a base year.
- The transmission peak forecast has been updated to reflect restructuring occurring among B.C.'s resource-based industries. The forecast also includes the closing of a large copper mine in 2007/08 in the South Interior.

Table 6.5. Comparison of Reference Peak Forecasts With Power Smart

	October 2003 Forecast (MW)	**December 2002 Forecast (MW)**	**October 2003 minus December 2002 (MW)**
1998/99	9077	9077	-
1999/00	8646	8646	-
2000/01	9319	9319	-
2001/02	9003	9003	-
2002/03	8816 (9405*)	9470	-654 (-65*)
2003/04	9620	9663	-43
2004/05	9687	9818	-131
2005/06	9787	9906	-119
2006/07	9881	10048	-167
2007/08	10017	10218	-201
2008/09	10144	10449	-305
2009/10	10274	10568	-294
2010/11	10385	10686	-301
2011/12	10502	10808	-306
2012/13	10660	10954	-294
2013/14	10816	11127	-311
2014/15	10991	11304	-313
2015/16	11166	11488	-322
2016/17	11342	11667	-325
2017/18	11517	11859	-342
2018/19	11692	12039	-347
2019/20	11867	12218	-351
2020/21	12043	12406	-363
2021/22	12218	12592	-374
2022/23	12393	12775	-382
2023/24	12568	-	-

* - Weather normalized actual for 2002/03

7 Sensitivity Analysis

BC Hydro's load forecast is sensitive to number of variables including weather, economic conditions, price, etc. BC Hydro's analysis has looked specifically at the sensitivity of the load to changes in the economy (GDP) and the price of electricity. In addition, a Monte Carlo analysis has been completed to look at the sensitivity of the load to a combination five causal factors that impact the forecast.

7.1. Sensitivity to GDP Changes

To estimate the impact of changes in the GDP forecast on electricity consumption, this forecast starts with the definition of the activity of GDP elasticity of consumption as shown in (7.1).

(7.1) $\eta = (\Delta C/C)/(\Delta Y/Y)$

Here

- Δ refers to a small change in the following variable;
- C refers to consumption in GWh; and
- Y refers to provincial GDP in billions of constant dollars.

The economic activity elasticity of consumption measures the percentage change in consumption caused by a one per cent change in economic activity.

Rearranging (7.1) gives (7.2), which expresses the relative percentage change in consumption as a function of the activity elasticity η and the relative or percentage change in economic activity.

(7.2) $(\Delta C/C) = \eta(\Delta Y/Y)$

Based on econometric analysis of weather-adjusted energy consumption over the period 1993-2002, the value of the activity elasticity is estimated at 0.42. The base GDP forecast is based on the growth rates presented in Table 4.2. The low GDP estimate assumes that the GDP growth rates are 50 per cent of those shown in Table 4.2. The high GDP estimate assumes that the GDP growth rates are 150 per cent of those shown in Table 4.2. The change in relative consumption compared to the reference forecast is then a straight-forward derivation using equation (7.2). Table 7.1 provides the forecast total gross requirements for the low GDP, base GDP and high GDP cases. Table 7.1 also provides the change in total gross requirements on both a GWh and percentage change basis for the low GDP scenario and the high GDP scenario compared to the base case.

Table 7.1. Sensitivity Analysis for Changes in GDP Assumptions Before Power Smart

	Total Gross Requirements (GWh) Under Low (50%) and High (150%) GDP Growth Scenarios			**Change in Total Gross Requirements (Change in GWh and Change in Percentage)**		
Case	Low	Base	High	Low	Base	High
2003/04	54680	54844	55009	-164 (-0.3)	None	164 (0.3)
2004/05	55156	55657	56158	-501 (-0.9)	None	501 (0.9)
2005/06	55616	56463	57310	-847 (-1.5)	None	847 (1.5)
2006/07	56128	57273	58419	-1146 (-2.0)	None	1146 (2.0)
2007/08	56750	58265	59780	-1515 (-2.6)	None	1515 (2.6)
2008/09	57401	59176	60951	-1775 (-3.0)	None	1775 (3.0)
2009/10	57977	60080	62183	-2103 (-3.5)	None	2103 (3.5)
2010/11	58638	61918	63398	-2380 (-3.9)	None	2380 (3.9)
2011/12	59263	61926	64589	-2663 (-4.3)	None	2663 (4.3)
2012/13	59863	62815	65767	-2952 (-4.7)	None	2952 (4.7)
2013/14	60439	63687	66935	-3248 (-5.1)	None	3248 (5.1)
2014/15	61051	64604	68157	-3553 (-5.5)	None	3553 (5.5)
2015/16	61734	65535	69336	-3801 (-5.8)	None	3801 (5.8)
2016/17	62309	66427	70546	-4119 (-6.2)	None	4119 (6.2)
2017/18	62969	67347	71725	-4378 (-6.5)	None	4378 (6.5)
2018/19	63564	68275	72986	-4711 (-6.9)	None	4711 (6.9)
2019/20	64242	69226	74210	-4984 (-7.2)	None	4984 (7.2)
2020/21	64949	70215	75481	-5266 (-7.5)	None	5266 (7.5)
2021/22	65622	71173	76725	-5552 (-7.8)	None	5552 (7.8)
2022/23	66325	72171	78017	-5846 (-8.1)	None	5846 (8.1)
2023/24	67043	73191	79339	-6148 (-8.4)	None	6148 (8.4)

7.2. Sensitivity to Price Changes

To estimate the impact of changes in the price forecast on electricity consumption, this forecast starts with the definition of the price elasticity of consumption shown in (7.3).

(7.3) $\varepsilon = (\Delta C/C)/(\Delta P/P)$

Again:

- Δ refers to a small change in the following variable;
- C refers to consumption in GWh; and
- P refers to an electricity price index.

The price elasticity of consumption measures the percentage change in consumption caused by a one per cent change in electricity price.

Rearranging (7.3) gives (7.4), which expresses the relative percentage change in consumption as a function of the price elasticity ε and the relative or percentage change in electricity price.

(7.4) $(\Delta C/C) = \varepsilon\ (\Delta P/P)$

Based on econometric analysis of weather-adjusted energy consumption over the period 1993-2002, the value of the price elasticity is estimated at -0.30. A review of the literature on electricity price elasticities suggests that this is high, so a value of -0.10 is also used in the sensitivity analysis. The base price forecast assumes that prices grow at the same rate as the CPI, or in other words that prices are constant in real terms, as shown by the price index set at 100.0. The rate increase scenario assumes that prices increase by six per cent in real terms in 2004/05, zero per cent in 2005/06, one percent in 2006/07, two percent in 2007/08 and are constant in real terms in subsequent years. The change in relative consumption compared to the reference forecast is then calculated using equation (7.4).

Table 7.2. Sensitivity Analysis for Changes in Price Elasticity Assumptions Before Power Smart

	Total Gross Requirements (GWh)			**Change in Total Gross Requirements (Change in GWh and Change in Percentage)**		
Case	Price = increase ε = -0.10	Price = constant	Price = increase ε = -.30	Price = Increase ε = -0.10	Price = constant	Price = Increase ε = -.30
2003/04	54844	54844	54844	- 0 (-0.0)	None	- 0 (-0.0)
2004/05	55379	55657	54822	- 278 (-0.5)	None	- 835 (-1.5)
2005/06	56181	56463	55616	- 282 (-0.5)	None	- 847 (-1.5)
2006/07	56929	57273	56242	- 344 (-0.6)	None	- 1031 (-1.8)
2007/08	57799	58265	56867	- 466 (-0.8)	None	- 1398 (-2.4)
2008/09	58703	59176	57756	- 473 (-0.8)	None	- 1420 (-2.4)
2009/10	59599	60080	58638	- 481 (-0.8)	None	- 1442 (-2.4)
2010/11	60530	61918	59554	- 488 (-0.8)	None	- 1464 (-2.4)
2011/12	61431	61926	60440	- 495 (-0.8)	None	- 1486 (-2.4)
2012/13	62313	62815	61307	- 503 (-0.8)	None	- 1508 (-2.4)
2013/14	63178	63687	62159	- 510 (-0.8)	None	- 1529 (-2.4)
2014/15	64087	64604	63054	- 517 (-0.8)	None	- 1551 (-2.4)
2015/16	65011	65535	63962	- 524 (-0.8)	None	- 1573 (-2.4)
2016/17	65896	66427	64833	- 531 (-0.8)	None	- 1594 (-2.4)
2017/18	66808	67347	65731	- 539 (-0.8)	None	- 1616 (-2.4)
2018/19	67729	68275	66636	- 546 (-0.8)	None	- 1639 (-2.4)
2019/20	68672	69226	67565	- 554 (-0.8)	None	- 1661 (-2.4)
2020/21	69653	70215	68530	- 562 (-0.8)	None	- 1685 (-2.4)
2021/22	70604	71173	69465	- 569 (-0.8)	None	- 1661 (-2.4)
2022/23	71594	72171	70439	- 577 (-0.8)	None	- 1708 (-2.4)
2023/24	72606	73191	71434	- 586 (-0.8)	None	- 1732 (-2.4)

7.3. Monte Carlo Analysis

A Monte Carlo analysis was completed to reflect a range of uncertainties implicit in the load forecast that includes factors beyond GDP and price. Monte Carlo analysis is a technique for estimating probabilities involving the construction of a model and the simulation of the outcome of an activity a large number of times. Random sampling techniques are used to generate a range of outcomes. Probabilities are estimated from an analysis of this range of outcomes

Five major causal factors were used to analyze the sensitivity of the forecast. These include: economic growth rate (reflected by GDP); the electricity rate; the effective energy reduction achieved by demand-side management (DSM) programs; the response to electricity price changes (price elasticity); and electricity intensity.

Probability distributions were assigned to each of these factors. Three values (low, probable and high) were established to reflect possible future levels of each of the factors, with a probability assigned to each.

An uncertainty model employing Monte Carlo simulation methods was used to quantify and combine the probability distributions, reflecting the relationships between the five causal factors and electricity consumption. A probability distribution was thus obtained which showed the likelihood of various load levels resulting from the combined effect of the five factors. This distribution is banded by:

- The low scenario: There is a 10 per cent chance the outcome will be below this value.
- The high scenario: There is a 10 per cent chance that the outcome will exceed this value.

Table 7.3 summarizes the results of the Monte Carlo uncertainty analysis on the energy and peak forecast before Power Smart. Tables A7.3 to A7.6 in Appendix 7 provides additional details of the high and low scenarios with and without Power Smart.

Table 7.3 Monte Carlo Analysis – Energy and Peak Before Power Smart

	Low Scenario		**Reference Forecast**		**High Scenario**	
	Total Gross Requirements (GWh)	Integrated System Peak (MW)	Total Gross Requirements (GWh)	Integrated System Peak (MW)	Total Gross Requirements (GWh)	Integrated System Peak (MW)
2002/03	53,339	8,816	53,339	8,816	53,339	8,816
2007/08	56,992	10,114	58,265	10,338	59,481	10,553
2012/13	60,382	10,743	62,815	11,175	65,334	11,622
2023/24	67,803	12,118	73,191	13,083	78,575	14,047
Growth Rates						
5 years 02/03 to 07/08	1.3%	2.8%	1.8%	3.2%	2.2%	3.7%
10 years 02/03 to 12/13	1.2%	1.9%	1.6%	2.4%	2.0%	2.7%
21 years 02/03 to 23/24	1.1%	1.5%	1.5%	1.9%	1.9%	2.2%
last 11 years 12/13 to 23/24	1.1%	1.1%	1.4%	1.4%	1.7%	1.7%

7.3.1. Uncertainty Assumptions

For each of the five major causal factors, a probability distribution defined by low, probable and high scenarios was assigned.

(a) Long-Term Economic Growth (GDP)

The long-term growth scenarios used were based on average annual GDP increases with a standard deviation of 0.5 per cent.

(b) Electricity Rates

The probable scenario assumes that electricity prices will increase at the rate of inflation (i.e. no increase in real terms). The low and high scenarios assume that annual electricity rate changes will be within a 2.5 per cent band of the probable rate changes.

(c) Effective Energy Reduction of Demand-Side Management (DSM) Programs

The annual low, probable and high reductions from DSM used were 50 per cent, 100 per cent and 150 per cent, respectively, of the expected reductions.

(d) Response to Electricity Price Changes (Elasticity)

The elasticity of electricity demand measures the change in the consumption of electricity in response to changes in variables influencing such demand. However, estimates of elasticity are subject to considerable uncertainty.

(e) Electricity Intensity

Changes in overall electricity intensity are assumed to be within a 0.2 per cent band of the annual change in electricity intensity for that year.

7.3.2. Temperature Sensitivity of Peak Demand

The forecasts and uncertainty bands described in Table 7.3 assume normal weather. They do not include the effect of colder or warmer than normal (30-year average) temperatures. The temperature sensitivity of peak demand can be quantified by examining the relationship between historical peaks with temperatures and adjusting for customer growth.

8 Residential Forecast

8.1. General

Residential sales, before considering the effects of Power Smart, are forecast to grow from 15,287 GWh in 2002/03 to 16,857 GWh in 2007/08, to 18,363 GWh in 2012/13, and to 21,743 GWh in 2023/24. These increases represent growth rates of 2.0 per cent over the next five years (2002/03 to 2007/08), 1.9 per cent over the next 10 years (2002/03 to 2012/13), and 1.5 per cent over the last 11 years of the forecast (2012/13 to 2023/24).

Mostly because of the warm winter of 2002/03, weather-normalized residential sales were estimated to be 15,464 GWh.

The two main drivers of the residential forecast are the forecast of the number of residential accounts, and the forecast of use rate (annual electricity consumption per residential account). Over the 10-year period between 1992/93 and 2002/03, the average annual increase in weather-normalized residential sales was 2.4 per cent. Future population growth in B.C. is projected to be lower than it was in the past due to lower economic growth. In addition, the use rate is not expected to continue growing as fast as it did in the past. Therefore, growth in residential electricity sales is projected to be lower than it was in the previous decade.

8.2. Methodology

At the end of the 2002/03 fiscal year, BC Hydro served 1,442,597 residential accounts. For the first four years of the forecast, growth in the number of residential accounts is based a housing start forecast provided by external consultants. This results in the number of residential accounts being projected to grow to 1,562,806 at the end of the 2007/08 fiscal year, which corresponds to an growth rate of 1.61 per cent. This compares with the population growth forecast of 1.12 per cent provided by the B.C. Statistics.

In the medium and long terms, the residential accounts forecast is based on the population forecast provided by B.C. Statistics, data from the Ministry of Management Services, regional economic forecasts and assumptions about the number of people per account. The population in the BC Hydro service area is projected to grow from 3.82 million in 2003 to 4.32 million in 2013, and to 4.83 million by 2023. These increases represent growth rates of 1.23 per cent over the next 10 years, and 1.19 per cent over the next 20 years. The corresponding growth rates for the number of residential accounts are 1.46 per cent and 1.35 per cent, respectively.

The use rate forecast is based on projections of factors such as housing mix (single family, row house, apartment, etc.), heating fuel choices (electric versus non-electric), appliance penetration rates, appliance lifespan and changes in electricity demands.

Currently, 20 per cent of BC Hydro's residential accounts are heated electrically, and on average they require about 14,700 kWh per year. Unless regulations or new laws are introduced, this share will likely increase, although the average usage may not change much for reasons stated below.

Ten years ago the average residential weather-normalized use rate was 10,350 kWh per year, and was increasing by about 125 kWh per year. However, growth in use rate has declined since then, with use rate currently at 10,790 kWh per year, and growing by only an average of 25 kWh per year for the last five years. Improvements in building insulation and appliance efficiency are the main reasons for the lack of growth in the annual residential use rate.

Over the longer term, use rate is not expected to change significantly because of the offsetting effects of the following residential trends.

- Increased electric space heating market share versus smaller housing units. Due to limited availability of land for residential development, the trend in major metropolitan centres is expected to be towards denser housing. Since row houses and apartments are more likely to be built with electric heat than single family homes, the market share for electrically heated housing is expected to increase. Although new row houses and apartments tend to be larger than existing similar dwellings, they are generally smaller in size than single family homes, and therefore have lower space heating load requirements. The increase in market share of electric space heating is also offset to some extent by improvements in building standards, and by the construction of the Vancouver Island gas pipeline, which has made gas space heat available to Island residents. However, natural gas prices are projected to be higher for Vancouver Island compared to the Mainland over the entire forecast period. As a result, the growth in the penetration rate of gas heating is anticipated to be slower for Vancouver Island than it was for the Mainland.
- More efficient appliances versus higher penetration. Manufacturers throughout Canada and the United States are expected to continue to improve the energy efficiency of major electrical appliances. As older models wear out and are replaced by newer ones, electricity consumption for major appliances such as refrigerators, freezers, ovens and ranges is forecast to decrease. However, new models of these major appliances tend to be larger than models currently in use. Some of the reduction in electricity use resulting from improvements in electricity efficiency will be offset by an increase in appliance size.
- A projected decrease in the number of people per household would tend to reduce electricity use per account. However, this reduction is expected to be offset by an increase in the penetration level of small appliances. An increase in electricity use is also projected from lifestyle changes and technological improvements. The latter are expected to cause an increase in demand for electronic, entertainment and telecommunication devices in the home. A trend towards home offices is also expected to produce a long-term increase in residential electricity consumption. In the long term, the expected overall impact of these various trends is that the factors working to increase the use rate will be offset by the factors working to decrease it, leading to the use rate levelling off.

8.3. Residential Sales Forecast

To develop the residential sales forecast for the entire BC Hydro service area, the total service area was divided into four customer service regions, and a forecast was prepared for each region. These regions are Lower Mainland, Northern Region, South Interior and Vancouver Island.

For each region, a housing stock forecast was prepared based on the number of residential accounts forecast in the region, and on other regional factors such as trends in housing mix and gas availability.

A use rate forecast was also developed for each region based on projections of penetration rates and individual consumption levels by end use (space heating, water heating, major appliances and small lifestyle appliances).

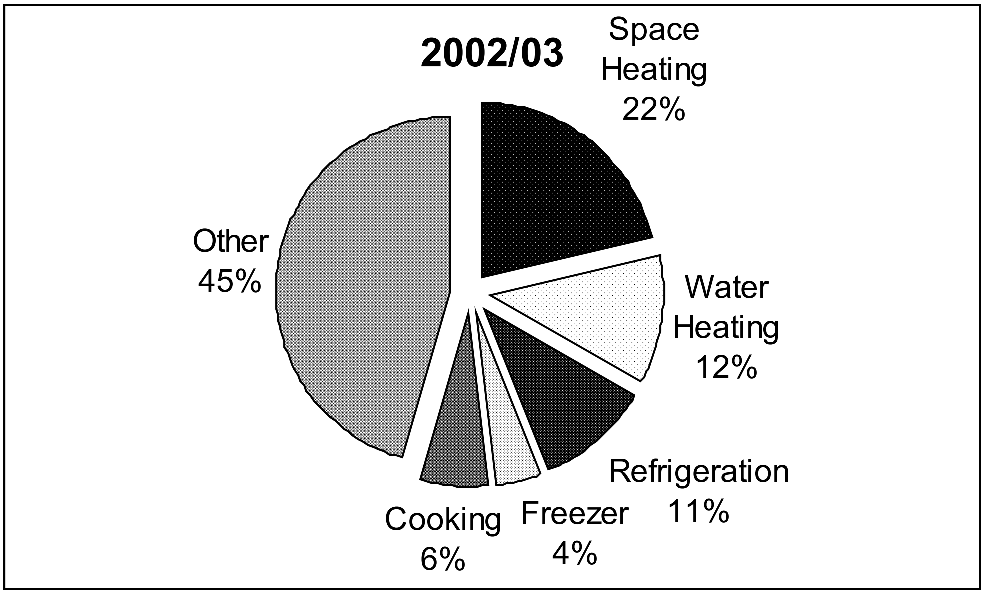
The residential sales forecast for a region is the sum of the requirements for each end use. The requirements for each end use are the product of the number of accounts having that end use and the energy used by an average account having that end use.

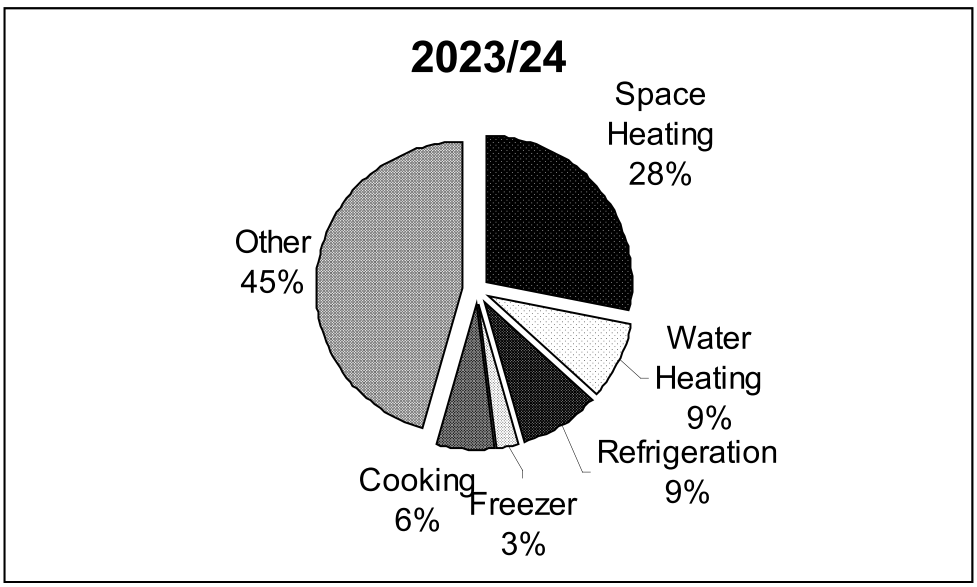
Table 8.1 forecasts residential sales before Power Smart, including sales by region. Figure 8.1 summarizes residential consumption by end use for the years 2002/03 and 2023/24.

Table 8.1. Residential Sales Before Power Smart

	BC Hydro Total	**Lower Mainland**	**Vancouver Island**	**South Interior**	**Northern Region**
	Sales	Sales	Sales	Sales	Sales
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)
Actual (weather-adjusted shown for 2002/03 in brackets)					
1997/98	13,802	7,187	3,719	1,518	1,378
1998/99	13,972	7,355	3,718	1,541	1,357
1999/00	14,572	7,670	3,909	1,583	1,409
2000/01	14,573	7,695	3,863	1,617	1,397
2001/02	15,090	7,975	4,001	1,656	1,458
2002/03	15,287 (15,464)	8,120 (8,201)	3,981 (4,049)	1,729 (1,749)	1,457 (1,465)
Forecast (Residential sales forecast based on "normal weather")					
2003/04	15,688	8,346	4,104	1,765	1,473
2004/05	15,955	8,508	4,165	1,793	1,490
2005/06	16,244	8,680	4,230	1,824	1,510
2006/07	16,544	8,851	4,301	1,857	1,534
2007/08	16,857	9,020	4,382	1,895	1,560
2008/09	17,134	9,160	4,458	1,931	1,585
2009/10	17,431	9,312	4,538	1,970	1,611
2010/11	17,737	9,469	4,619	2,010	1,638
2011/12	18,058	9,633	4,706	2,052	1,667
2012/13	18,363	9,785	4,792	2,093	1,694
2013/14	18,671	9,936	4,877	2,136	1,721
2014/15	18,982	10,090	4,964	2,180	1,748
2015/16	19,293	10,244	5,050	2,225	1,775
2016/17	19,604	10,397	5,136	2,269	1,802
2017/18	19,914	10,550	5,220	2,315	1,830
2018/19	20,223	10,701	5,303	2,361	1,858
2019/20	20,529	10,851	5,385	2,407	1,887
2020/21	20,835	11,000	5,467	2,453	1,915
2021/22	21,139	11,148	5,548	2,500	1,943
2022/23	21,441	11,295	5,628	2,547	1,971
2023/24	21,743	11,443	5,707	2,595	1,999
Growth Rates					
5 years: 97/98 to 02/03	2.1%	2.5%	1.4%	2.6%	1.1%
5 years: 02/03 to 07/08	2.0%	2.1%	1.9%	1.9%	1.4%
10 years: 02/03 to 12/13	1.9%	1.9%	1.9%	1.9%	1.5%
11 years: 12/13 to 23/24	1.5%	1.4%	1.6%	2.0%	1.5%

Figure 8.1. Residential Consumption by End Use for Selected Years





9 Commercial Forecast

9.1. General

BC Hydro's commercial sector provides electricity to the British Columbia's service sector. It includes customers who operate a wide range of facilities such as office buildings, retail stores, institutions (i.e., hospitals and schools) and transportation infrastructure. The largest portion of these facilities are buildings, such as offices, restaurants, hotels, retail stores, etc. The remainder includes facilities such as transportation infrastructure and public utilities.

The commercial sales forecast is based primarily on a bottom-up or end-use forecast. This methodology focuses on the "stock" of buildings or facilities and how they consume energy in the sector. There are also top-down components to the forecast driven by general economic indicators (i.e., GDP and employment) that account for year-to-year fluctuations in electricity sales as a result of changes in occupancy of the building stock.

Sales to BC Hydro's commercial sector in 2002/03 grew by 1.1 per cent reflecting the moderate performance of the economy in general. This contrast to previous swings in sales, such as the –0.5 per cent growth experienced in 2001/02 and the 3.6 per cent growth in 2000/01, corresponding to years where the economy's performance was relatively weak and strong respectively.

In anticipation that the economy is on a gradual upswing, growth is expected to be 1.3 per cent in 2003/04 and at an average annual growth of 1.9 per cent, 1.9 per cent and 1.7 per cent over the next five, 10, and for the last 11 years of the forecast respectively. All forecast values are before any energy conservation programs are taken into account, that is, before Power Smart.

9.2. Methodology

The building portion of the commercial sector accounts for approximately 77 per cent of the commercial sector sales. Non-buildings account for approximately 23 per cent of the commercial sector load and include facilities such as transportation and communication infrastructure, pipeline transport, grain elevators and utilities.

As an end-use or bottom-up forecast, BC Hydro's commercial sector forecast focuses on the demand for energy consuming end uses (i.e. heat, light and refrigeration) to meet the requirements for commercial buildings. In its simplest form, the forecast is the product of the commercial sector building floor stock (i.e. the floor area in square feet) and the intensity of end-use demand per unit of floor stock. BC Hydro's forecast disaggregates commercial buildings in the province into 13 building types, listed in Table 9.1, and up to 10 different end uses (i.e. space heating, lighting, hot water, ventilation, etc.).

Table 9.1. BC Hydro Commercial Sector Building Types

Small Office	Large Office
Non-Food Retail	Grocery
Restaurants	Warehouse
Schools	Colleges/Universities
Hotel/Motel	Hospitals
Nursing Homes	Apartments
Other Buildings	

Notes: Apartments include apartment common areas only. Other Buildings includes amusement and recreation facilities, religious organizations and protective services.

The growth of commercial floor stock depends on many different factors including economic trends, population growth, demographics and employment. For example, an aging population will require an increased number of health care facilities and growth in tourism will be reflected in the number of hotels, restaurants and recreation facilities.

The intensity of end-use demand will change with factors such as the turnover of building stock and the evolution of the energy end-use technology. This can have both positive and negative impacts on energy intensity. As an example, some of the trends in new buildings that act to reduce energy intensities include:

- change to T8 linear fluorescent lighting with electronic ballasts;
- improved thermal building characteristics with higher insulation levels;
- double pane with thermal break window glazing; and
- improved cooling equipment efficiencies.

In contrast, other loads will put an upward pressure on building energy consumption, such as:

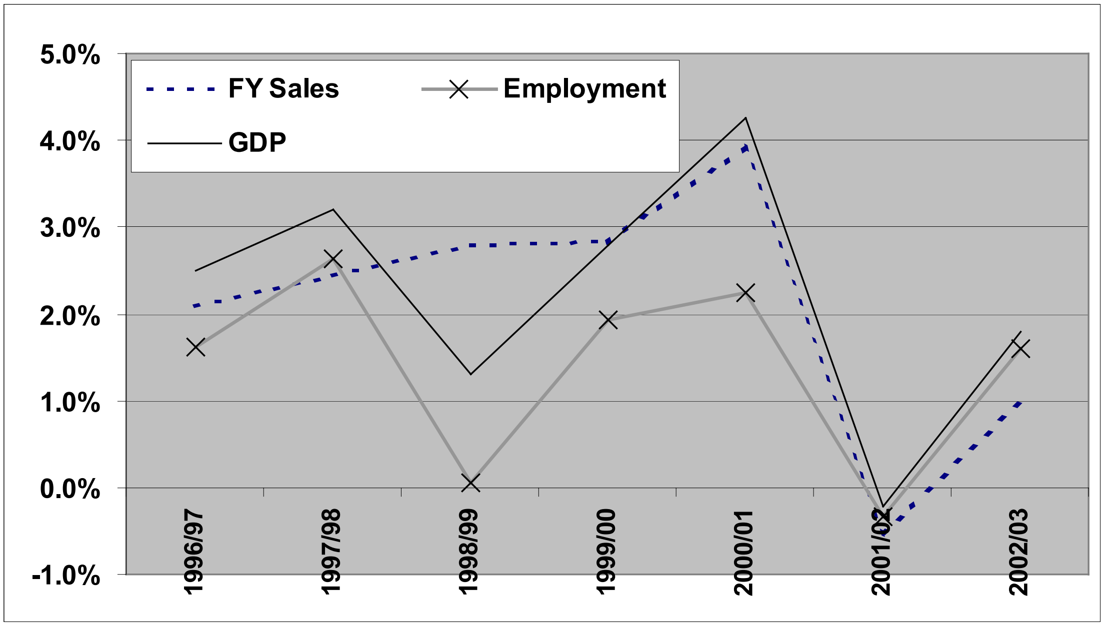
- greater lighting levels in retail stores;
- increased use of computers and other plug loads;
- new design practices that require higher ventilation rates in some buildings, such as in schools and hospitals; and
- increased saturation of space cooling in selected segments.

Electricity sales in the commercial sector building stock also depend on the level of economy activity as a whole, regardless of the installed floor stock. For example, electricity sales to stores, warehouses or hotels will vary with factors such as retail sales, wholesale/retail trade and tourism. Significant fluctuations in electricity sales growth in the commercial sector can result from changes in the performance of the local economy.

In addition, it is assumed the growth in the non-building commercial facilities will vary with trends in the high-level drivers: GDP, employment and population.

Figure 9.1 summarizes the historical relationship between growth in commercial sector electricity sales and growth in provincial employment and GDP.

Figure 9.1. Historic Growth Rates – Sales, Employment and GDP



As a result, the commercial forecast relies extensively on both short- and long-term population, demographic and economic forecasts. In the short term, variations in the economy on a year-to-year basis will effect electricity sales in terms of occupancy rates and/or performance of the province's commercial buildings and facilities. In the long term, the size and structure of the economy as well as the size and age of the population will dictate what types of commercial buildings and facilities are constructed to meet the needs of the province's service sector. Over the long term, commercial sales growth is likely to be influenced by factors including:

- A growing population, which increases the demand for most general services (institutions, retail activity, etc.);
- A gradual shift in the structure of British Columbia from a goods-based to a more service-based economy;
- An aging population, which will require increased heath care services;
- Increases in electric intensity, a result of greater use of electronic and information end-use technologies;
- Continued growth in the tourism sector;
- New electricity-using technologies becoming more common in commercial establishments;
- Continued growth of Vancouver as an international finance centre;
- B.C.'s continued role as Canada's link with Pacific markets; and
- The potential for further development of a high tech sector within the province.

9.3. Major Trends

The B.C. economy continues to be strongly influenced by primary resource industries and their associated international markets. B.C.'s service sector has however been growing significantly in recent years and currently employs 80 per cent of the total provincial population and is responsible for approximately 76 per cent of the province's GDP, compared to the 20 per cent and 24 per cent for employment and GDP for the goods-producing sector. As a result, the service sector has been the primary employment growth engine for the province and this trend is expected to continue. In addition, the B.C. service sector is also much less susceptible to fluctuations in international markets than the goods-producing sector, which contributes to its stronger and more stable growth.

The impact of the 2010 Winter Olympic Games has not been directly incorporated into this forecast due to the lack of detailed economic impact studies at the time the forecast was produced. Preliminary, high level impacts of Games were estimated by the province to be:

- $2.1 billion increase in direct GDP;
- $3.3 billion increase in total GDP including multiplier impacts; and
- 77,000 person years of employment.

Compared to total provincial GDP ($126,141 million 1997 dollars in 2002) and employment levels (1,973,000 in 2002), these impacts are relatively small when they are spread out over the years leading up to and after the Games. In the areas directly impacted by the Olympics, there will be some obvious growth in commercial electricity sales as facilities are constructed and put in operation. It is also expected that there will be a period of declining growth immediately following the Games as growth rates fall back to more sustainable levels. The most significant impact of the Games for commercial sales will be in the ability of the event to attract business to the area over the long term. As more detailed information about the impacts of the Olympics are available, it will be incorporated into the forecast.

The following discussion outlines some of the regional trends that impact the province's commercial buildings and their consumption of electricity.

9.4. Lower Mainland

Sales to the commercial sector in the Lower Mainland vary across the region. Greater Vancouver's commercial sector growth is relatively strong due to its extensive service and high technology sectors. In other parts of the region, a mixture of agriculture, resource development and tourism will have their own impacts on sales. Overall, it is expected that commercial sales growth before Power Smart in the Lower Mainland will be 2.0 per cent, 1.9 per cent and 1.7 per cent over the next five, 10, and for the last 11 years of the forecast respectively.

Growth in commercial building floor stock is expected to be near historic levels with slightly higher rates in areas such as Greater Vancouver, some parts of the Fraser Valley and Whistler. Retail sales are expected to continue to remain high over the next two years, having a positive impact on electricity sales to non-food retail, grocery, warehouses and restaurants. Growth in hotels and motels is expected to continue at near historic levels[8]. Office space is not expected to increase dramatically in the short term in the Vancouver area due to relatively high vacancy rates following a significant period of new office construction. In the communities of the Sunshine Coast, it is expected that there will be some gradual increases in commercial growth resulting from a shift to a more service-based economy.

Institutional buildings will likely see only moderate growth over the forecast period. Hospitals will see little growth in the short term due to limitations in health authority funding, expansions of some facilities and closures of others. Growth in nursing homes are expected, however, to be closer to historic levels. Education facilities are likely to see some expansion in the Vancouver area early in the forecast period due to the opening of several schools in the region, expansion of UBC and the possible development of the proposed Sea to Sky University.

9.5. Vancouver Island

Sales to Vancouver Island's service sector will be the result of a variety of mixed trends over the next few years. Overall the region's sector is expected to grow at 1.4 per cent, 1.8 per cent and 1.9 per cent over the next five, 10, and for the last 11 years of the forecast, respectively, before Power Smart.

Contributing to this relatively low growth is the expectation of continued government restructuring, the softwood lumber agreement and uncertainty in the resource markets (forestry, fishing and mining). A lower population growth forecast for the region is anticipated to have an impact on future sales to institutional buildings (education and health). The tourism industry is expected to continue to flourish and, when coupled with strong retail sales, will result in floor stock growth for the retail sector and lodging. Some growth in office floor space is expected in the mid-term in anticipation that any increases of vacant office space caused by government restructuring will slowly be absorbed.

9.6. South Interior

It is expected that many parts of B.C.'s South Interior region will benefit from increased diversification of the economy. As a result, the forecast for electricity sales to the commercial sector in the South Interior is anticipated to grow at 2.0 per cent, 2.1 per cent and 2.1 per cent over the next five, 10, and for the last 11 years of the forecast, respectively, before Power Smart.

Much of this diversification comes from a flourishing tourism industry (including golf courses, casinos and ski resorts) that is likely to translate into increased growth to the retail, restaurant and hotel/motel sub-sectors. Other factors such as the closure of Highland Valley Copper (expected to begin in 2007/08) and uncertainties in the resource sector will likely have a moderating effect on this growth.

Growth in sales to the institutional sector (health and education buildings) will vary across the region. In some resource-based communities, growth is expected to be slow due to low population growth and population outflows. In other areas, such as Thompson-Okanagan, growth in electricity sales to the

[8] A significant increase in hotel floor stock as a result of the Olympic Games is not expected as it would outstrip demand over the long term, increasing vacancy rates.

sector is expected to be stronger with a higher population growth and the region's growing percentage of retirees.

9.7. Northern Region

Commercial electricity sales in the Northern Region are expected to grow, before Power Smart, at 1.4 per cent, 1.5 per cent and 1.4 per cent over the next five, 10, and for the last 11 years of the forecast, respectively. This moderately low growth is a result of the expectation that the region will continue to be heavily dependent of resource-based industries. Softness in the forestry sector has contributed to a modest economic outlook and a negative net migration for the region. Partially offsetting these decreases is an expectation of an improving outlook in the mining industry. Some growth in office floor stock is anticipated with an improving economic outlook and as commodity prices increase. As in other parts of the province, strong retail sales forecasts are expected to support electricity sales growth in the retail sector, as well as in restaurants and in hotels and motels.

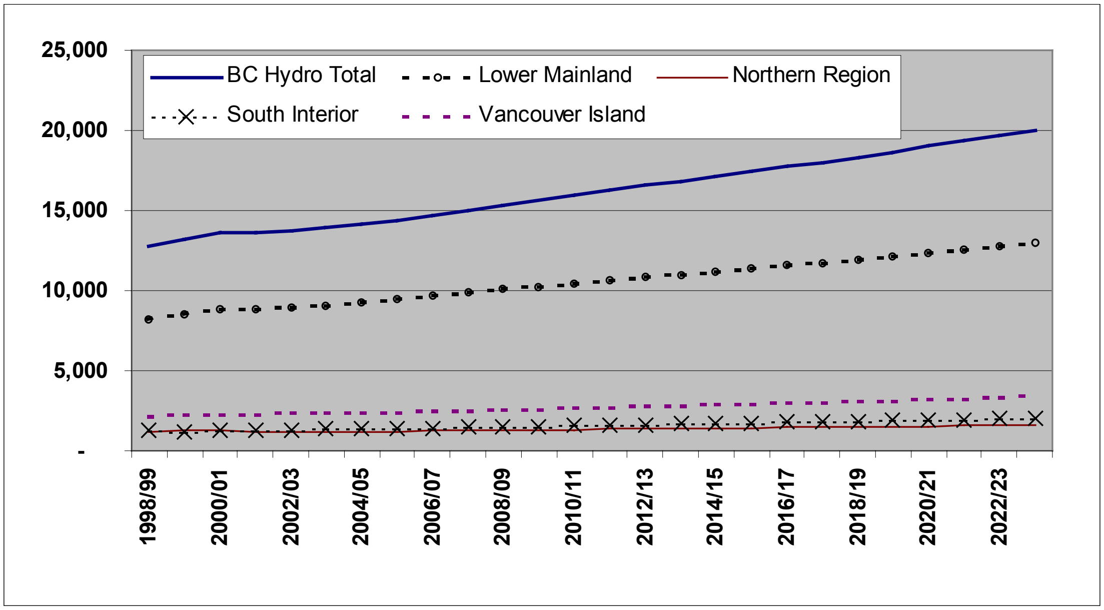
Low population growth will likely limit growth and sales to the institutional sector including hospitals and nursing homes, although the region will receive a boost with the development of the Prince George Regional Hospital. Sales to educational buildings are expected to be low due to declining enrolment resulting from low population growth and funding limitations.

Table 9.2 and Figure 9.2 summarize the total BC Hydro and regional commercial sector forecast before Power Smart. Figure 9.3 illustrates the links between commercial sector sales, provincial GDP and employment historically and over the forecast period.

Table 9.2. BC Hydro Regional Commercial Sales Forecast Before Power Smart

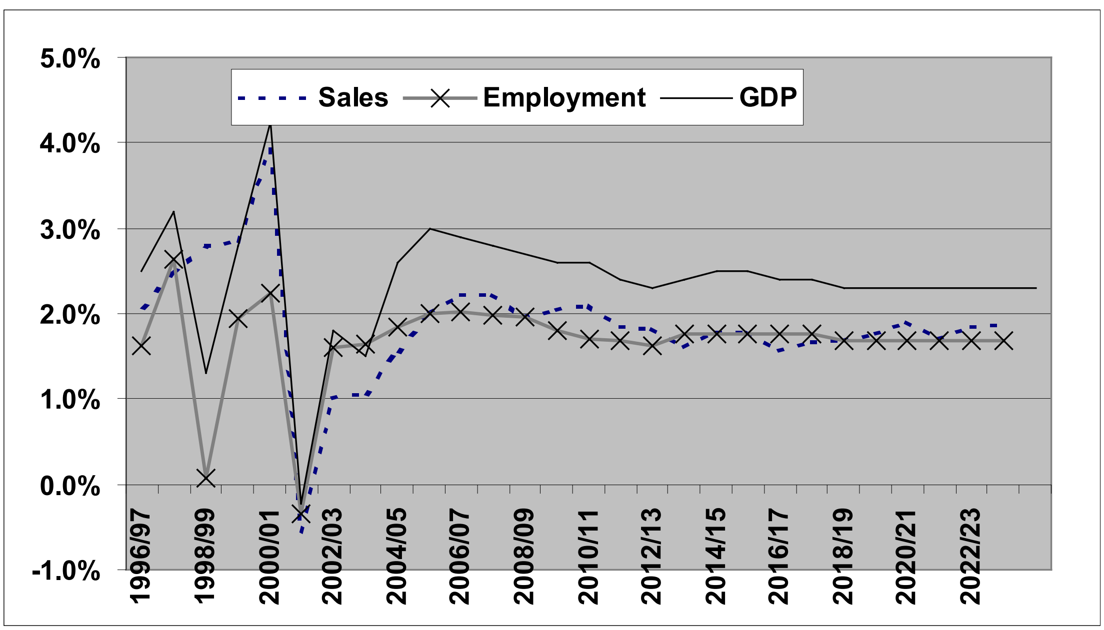
	BC Hydro Total	Lower Mainland	Northern Region	South Interior	Vancouver Island
	Sales (GWh)	Sales (GWh)	Sales (GWh)	Sales (GWh)	Sales (GWh)
Actual					
1997/98	12,466	7,991	1,211	1,158	2,106
1998/99	12,814	8,213	1,216	1,232	2,153
1999/00	13,176	8,478	1,249	1,208	2,241
2000/01	13,654	8,871	1,233	1,264	2,286
2001/02	13,583	8,828	1,180	1,298	2,277
2002/03	13,729	8,938	1,178	1,323	2,290
Forecast					
2003/04	13,908	9,078	1,191	1,339	2,299
2004/05	14,120	9,236	1,204	1,362	2,318
2005/06	14,403	9,435	1,219	1,394	2,355
2006/07	14,723	9,652	1,239	1,427	2,405
2007/08	15,050	9,868	1,263	1,460	2,459
2008/09	15,346	10,066	1,282	1,492	2,507
2009/10	15,658	10,265	1,304	1,528	2,560
2010/11	15,985	10,469	1,328	1,561	2,627
2011/12	16,281	10,653	1,349	1,598	2,681
2012/13	16,578	10,841	1,368	1,633	2,736
2013/14	16,844	11,009	1,385	1,665	2,786
2014/15	17,143	11,198	1,404	1,700	2,841
2015/16	17,449	11,391	1,424	1,736	2,898
2016/17	17,722	11,563	1,440	1,769	2,949
2017/18	18,015	11,747	1,459	1,806	3,003
2018/19	18,320	11,937	1,479	1,843	3,060
2019/20	18,642	12,139	1,501	1,883	3,119
2020/21	18,995	12,361	1,524	1,926	3,184
2021/22	19,319	12,563	1,545	1,967	3,244
2022/23	19,673	12,785	1,569	2,011	3,309
2023/24	20,040	13,015	1,593	2,055	3,376
Growth Rates					
5 years: 97/98 to 02/03	1.9%	2.3%	-0.6%	2.7%	1.7%
5 years: 02/03 to 07/08	1.9%	2.0%	1.4%	2.0%	1.4%
10 years : 02/03 to 12/13	1.9%	1.9%	1.5%	2.1%	1.8%
11 years: 12/13 to 23/24	1.7%	1.7%	1.4%	2.1%	1.9%

Figure 9.2. BC Hydro Regional Commercial Sales Forecast Before Power Smart



As discussed above, there is a relatively strong correlation between electricity sales to BC Hydro's commercial sector and high-level economic indicators. Figure 9.3 summarizes the relationship of the commercial sector sales forecast and the provincial GDP and employment forecast.

Figure 9.3. Growth Rate Comparisons



10 Industrial Forecast

10.1. General

British Columbia's industrial sector is based primarily on resource extraction and processing. Key activities include metal mining, coal mining, ore processing and smelting, wood extraction, saw milling, pulp and paper and chemical production. Approximately 80 per cent of BC Hydro's industrial sector is made up of large-scale customers involved in the extraction and processing of natural resources and the remaining are smaller manufacturing companies. Before considering the effects of Power Smart, industrial sales are forecast to grow from 18,596 GWh in 2002/03 to 19,139 GWh in 2007/08, to 20,042 GWh in 2012/13, and to 22,283 GWh in 2023/24. These increases represent modest growth rates of 0.60 per cent over the next five years (2002/03 to 2007/08), 0.8 per cent over 10 years (2002/03 to 2013/14), and 1.0 per cent over the last 11 years of the forecast (2012/13 to 2023/24).

Because of the importance of the forestry, pulp and paper and mining sectors for BC Hydro's electricity load, this section summarizes the current situation in each sector.

10.1.1. Medium-Term Forestry Outlook

Shipments of lumber from British Columbia, which have recently been averaging between 12 billion and 13 billion board feet per year, now go almost entirely to the United States, Japan and other parts of Canada. Shipments to European and other markets, which peaked at about 1.5 billion board feet in the late 1980s, have fallen to about 500 million board feet. This means that the health of the B.C. lumber market depends critically on the strength of the American and Japanese economies as well as the degree of market access for B.C. lumber. The American lumber market is beginning to show some domestic strength, but no early resolution to the softwood lumber dispute is expected.

Key issues for B.C. lumber sales in the medium term include:

- Changes in domestic timber supply. Move to smaller, poorer quality, second growth timber on Vancouver Island and destruction of large volumes of wood by beetles are expected to raise timber costs.
- Changes in lumber demand. On-going oversupply in the North American market are likely to continue to provide downward pressure on prices and lead to more rationalization and mill closures.
- Impact of market access disputes. On-going disputes create uncertainty, reduce cash flow and limit opportunities for upgrading B.C. mills.

10.1.2. Medium-Term Pulp and Paper Outlook

B.C. pulp capacity is about 9.3 million metric tons per year, with about 58 per cent bleached softwood kraft pulp, 28 per cent thermo-mechanical or chemi-thermo-mechanical pulp, five per cent unbleached kraft and about nine per cent in other grades. Consolidation in the pulp and paper industry, coupled with three years of relatively poor markets in both North America and overseas, have led to strong pressures to rationalize production and reduce costs. A number of

B.C. pulp and paper mills are high-cost producers, and rising fibre costs combined with a strong Canadian dollar have further weakened profitability.

Key issues for B.C. pulp and paper sales in the medium term include:

- Ongoing decline in the North American newsprint market, which is expected to foreshadow a decline in the world newsprint market.
- Slowing demand growth for most printing and writing paper grades, with some limited bright spots such as directory paper.
- Growing demand for paper products on the part of China (a positive factor for B.C.) combined with expected increased supply in China from new and very large mills (a negative factor for B.C.).
- Rationalization of the pulp and paper industry, leading to decisions on investment and upgrading made on a global basis, with negative implications for high cost paper machines and pulp and paper mills, including some B.C. facilities.

10.1.3. Medium-Term Mining Outlook

The mining sector had gross sales of some $3.5 billion in 2003, the most recent year for which comprehensive information is available. At present, some 20 mines purchase power from BC Hydro, with more metal mines than coal mines. Production is primarily for export, often after minimal domestic processing. Coal is sold primarily to Japan, although that market has been declining with the down-sizing of the Japanese steel industry. Precious and base metals are sold to a number of countries. Although once a major world player in the base metal industry, the domestic industry has been in decline for a number of years.

Key issues for B.C. mining sales in the medium term include:

- A surge in the Canadian dollar has reduced profitability for many B.C. mines since costs are largely in Canadian dollars while earnings are in U.S. dollars;
- Exploration activities have been limited for a variety of reasons including concerns over unresolved native land claims; and
- Few high quality ore deposits have been discovered in B.C. over the past decade, while major finds have taken place in Latin America and Indonesia.

10.2. Methodology

The main determinant of industrial electricity sales is the level of forecast activity in the industrial sector. In the short term (the first four years of the forecast), the forecast for the large industrial customers is done on a customer-by-customer basis. In the medium to long terms, since no specific forecast information by customer for the industrial sector is available, the forecast uses total GDP as a proxy. At present, three sources of information on GDP are used for the load forecast. These sources are:

- B.C. Ministry of Finance, Budget and Fiscal Plan 2003/04, February 2003, and September 2003 Update;
- Malatest and Associates, July 2003; and
- A ratio based on U.S. Department of Energy forecast for Canadian GDP, Annual Energy Outlook 2003, December 2002.

For the period 2003 through 2007, the GDP forecast is a weighted average of the B.C. Ministry of Finance and the Malatest and Associates Forecast. For 2008 through 2022, the GDP forecast is a weighted average of the Malatest and Associates and the DOE forecasts.

This forecast uses a weighted average for the following reasons:

- Since the three forecasts are based on somewhat different data sources and methodologies, pooling information through a weighted average forecast reduces risk;
- The B.C. Ministry of Finance forecast is not available for the 20 years needed for the load forecast so the B.C. Ministry of Finance forecast needs to be supplemented by other forecasts; and
- The weighted average forecast appears to track future outcomes better than a single forecast.

The industrial distribution energy forecast methodology is explained in Section 3.

10.3. Industrial Forecasts

Table 10.1 summarizes alternative econometric estimates of the determinants of electricity consumption for the industrial sector and compares them to the reference forecast developed with the above methodology. The regressions are as follows:

- OLS (A). Ordinary least squares regression of industrial sales on GDP (Ordinary least squares regression is a method of choosing parameters to minimize the sum of squares of errors produced as a function of a set of variables. See Appendix 5.);
- OLS (B). Ordinary least squares regression of industrial sales on GDP with a dummy variable for 1997 because of work stoppages;
- ML (A). Maximum likelihood regression of industrial sales on GDP (Maximum likelihood regression is a method to choose estimates for parameter values that maximize the probability that estimated parameters will represent an observed sample. See Appendix 6.); and
- ML (B). Maximum likelihood regression of industrial sales on GDP with a dummy variable for 1997 because of work stoppages.

The OLS industrial consumption equations have an acceptable fit with adjusted R-squared values of 0.30 and 0.79, although the Durbin-Watson statistic suggests the presence of auto-correlation. (The Durbin-Watson is a measure of auto-correlation, which means that the errors are correlated over time rather than being independent as assumed in the ordinary least squares model. If the errors are auto-correlated, then use of a maximum likelihood estimation procedure may lead to statistically superior estimates.) The ML (A) industrial consumption equations look reasonable with coefficients having the anticipated signs. Once again, the Durbin-Watson statistic is better suggesting that auto-correlation has been reduced. ML (B) is the slightly preferred regression because of the excellent determination of the coefficients, but the other regressions are very similar. According to this model, a one billion dollar increase in provincial GDP increases the industrial demand for electricity by 48 MWh.

Table 10.1. Econometric Models of Industrial Sales

Variable	OLS (A)	OLS (B)	ML (A)	ML (B)
Constant	12076 (2532)	12348 (1377)	11928 (1937)	12326 (523)
GDP	0.0487 (.022)	0.0476 (.012)	0.0498 (.017)	0.0476 (.005)
Dummy	-	-1457 (325)	-	-1383 (160)
Adjusted R-sq	0.30	0.79	-	-
Log likelihood	-	-	-75.9	-64.9
Durbin-Watson	2.53	3.28	2.10	3.25

Table 10.2 compares the forecasts based on the OLS and ML regression analyses with the reference forecast before Power Smart. The OLS (A) forecast rises from 18,315 GWh in 2003/04 to 22,280 GWh in 2023/24. The ML forecast is very similar, rising from 18,447 GWh in 2003/04 to 22,321 GWh in 2023/24. The OLS (B) forecast rises from 18,415 GWh in 2003/04 to 22,365 GWH in 2023/24. Again, the ML forecast is very similar rising from 18,415 GWh in 2003/04 to 22,283 GWh in 2023/24. The reference forecast is lower in most years than the econometric forecasts, rising from 18,409 GWh in 2003/04 to 20,283 GWh in 2023/24.

Table 10.2. Alternative Industrial Forecasts Before Power Smart (GWh)

Year	OLS(A)	OLS(B)	ML(A)	ML(B)	Reference (Table 10.3)
2003/04	18315	18447	18310	18415	18409
2004/05	18478	18605	18476	18573	18679
2005/06	18670	18793	18672	18760	18806
2006/07	18861	18980	18868	18947	18913
2007/08	19058	19172	19069	19139	19139
2008/09	19246	19356	19262	19323	19323
2009/10	19433	19539	19453	19505	19505
2010/11	19624	19726	19648	19692	19692
2011/12	19805	19903	19834	19868	19868
2012/13	19983	20077	20016	20042	20042
2013/14	20172	20262	20210	20227	20227
2014/15	20367	20452	20408	20417	20417
2015/16	20566	20646	20612	20611	20611
2016/17	20770	20846	20820	20810	20810
2017/18	20978	21050	21034	21013	21013
2018/19	21183	21250	21243	21213	21213
2019/20	21393	21454	21457	21417	21417
2020/21	21607	21664	21677	21627	21627
2021/22	21826	21878	21901	21840	21840
2022/23	22050	22097	22131	22059	22059
2023/24	22280	22321	22365	22283	22283

10.4. Forecast Sales by Sector

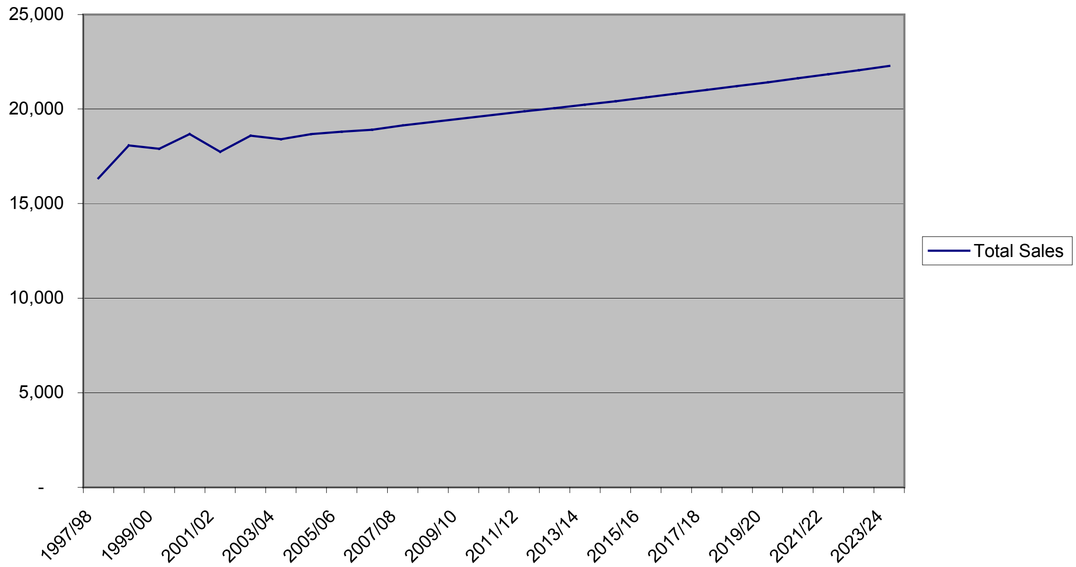
Table 10.3 summarizes the forecast load by industrial sector. All sectors are expected to experience annual growth of less than 2.0 per cent per year. Figure 10.1 summarizes total industrial sales.

Table 10.3. Industrial Sales by Sector Before Power Smart (GWh)

	Transmission Voltage Customers						Dis-tribution	
	Metal Mines	Coal Mines	Wood	Paper	Chem-ical	Other Trans-mision Rate	All Sectors[1]	Total Sales
Actual								
1997/98	1602	662	769	7076	1694	750	3786	16339
1998/99	2006	574	765	8501	1685	727	3820	18077
1999/00	1619	558	826	8685	1710	663	3828	17890
2000/01	1996	547	892	8937	1724	856	3627	18679
2001/02	1952	554	885	7957	1626	880	3884	17739
2002/03	1873	516	928	8534	1798	902	4046	18596
Forecast								
2003/04	1843	480	898	8418	1734	936	4100	18409
2004/05	1843	500	888	8595	1734	936	4183	18679
2005/06	1843	525	888	8595	1734	936	4285	18806
2006/07	1843	535	883	8595	1734	936	4387	18913
2007/08	1426	610	920	8910	1808	976	4489	19139
2008/09	1438	612	928	8952	1822	984	4587	19323
2009/10	1063	639	969	9218	1903	1028	4685	19505
2010/11	1076	647	981	9237	1928	1041	4782	19692
2011/12	1083	651	987	9290	1939	1047	4870	19868
2012/13	1089	655	993	9345	1951	1054	4956	20042
2013/14	1095	662	1000	9407	1954	1061	5049	20227
2014/15	1101	670	1007	9471	1957	1068	5144	20417
2015/16	1107	678	1014	9537	1960	1075	5240	20611
2016/17	1114	686	1021	9607	1965	1083	5334	20810
2017/18	1121	694	1029	9678	1969	1091	5430	21013
2018/19	1128	702	1037	9749	1973	1099	5524	21213
2019/20	1135	711	1045	9821	1978	1108	5619	21417
2020/21	1143	719	1053	9897	1983	1116	5716	21627
2021/22	1150	728	1061	9974	1988	1125	5813	21840
2022/23	1158	738	1070	10054	1994	1134	5911	22059
2023/24	1166	747	1079	10137	2000	1143	6011	22283
Growth Rates								
5 years 97/98 to 02/03	3.2%	-4.9%	3.8%	3.8%	1.2%	3.8%	1.3%	2.6%
5 years 02/03 to 07/08	-5.3%	3.4%	-0.2%	0.9%	0.1%	1.6%	2.1%	0.6%
10 years 02/03 to 12/13	-5.3%	2.4%	0.7%	0.9%	0.8%	1.6%	2.0%	0.8%
11 years 12/13 to 23/24	0.6%	1.2%	0.8%	0.7%	0.2%	0.7%	1.8%	1.0%

Notes: 1. Excluding distribution rate transmission voltage (DRTV)

Figure 10.1. Total Industrial Sales (GWh)



10.5. Risks and Uncertainties

The main risks to the industrial forecast pertain to sales to the base metal mining and pulp and paper sectors. Highland Valley Copper has publicly stated that, based on forecasts of copper prices earlier in the year, it expects to decommission beginning in 2007/08. This action is subject to the market situation at the time and would be accompanied by a couple of years of reclamation. As well, there are other potential large-scale additions or reductions to existing industrial facilities that may or may not take place depending on market opportunities going forward.

For the industrial forecast, this raises two issues to address:

- First, how far out and on what basis of support can BC Hydro make forecasts on production and electricity purchases of specific customers or specific sectors;
- Second, how should BC Hydro address the inherent unevenness of closures and plant additions of industrial activities on the upside and downside.

The most accurate and defensible way to forecast over the longer term is on the basis of relationship to forecast GDP, since BC Hydro cannot forecast its customers' levels of activity in the longer term, either up or down. There is a solid statistical relationship between industrial consumption and growth, and this produces a growth curve that can be referenced and supported at a provincial level. By definition, this approach to forecasting does not contemplate large-scale, specific sector or specific customer reductions or additions.

Because BC Hydro aggregates forecasts by sector and region, it needs to reconcile or re-balance the sectoral and regional information with the total. If the forecast is reduced for a particular plant closure, it deviates from the overall GDP forecast approach, and is one-sided in adjusting on the down side for one customer without reflecting the corresponding but unknown potential for large-scale expansions. The appropriate solution, in our view, is thus to reflect Highland Valley in the regional and sectoral information and redistribute load to the other sectors on a weighted basis. For revenue requirements, this is an issue beyond the test years, and an on-going review and forecast revision is expected as more information becomes available.

11 Peak Forecast

11.1 Introduction

Regional peak forecasts are an outlook of the peak demand for electricity for each of the four BC Hydro planning regions (i.e. Lower Mainland, Vancouver Island, South Interior and Northern Region). These forecasts are typically generated for a 20-year period and are used to support generation transmission and distribution planning requirements. Aggregating the regional peak forecasts produces the total integrated system peak forecast.

This section describes the method of generating the peak forecasts. It includes an explanation of the drivers of the various peak forecasts that are assembled to develop the regional and system peak forecast. The forecast is prepared based on an assumption of normal weather, and its role in formulating the distribution peak forecast is discussed. (See Appendices 3 and 4 for a detailed discussion of the method of normalizing weather in energy and peak forecasting.) The 2003/04 total regional and system peak forecast is presented and explained and issues related to peak forecasting are outlined at the end of the section.

11.2. Peak Forecast Method

Within each regional the peak is composed of the demand for electricity at the distribution level (i.e. residential and commercial/light industrial loads) transmission customer loads (i.e. large industrial loads) and any inter-utility sales plus transmission and distribution losses.

For the purposes of preparing the distribution peak forecast there are 3 important inputs

1. Weather normalized peak load which forms the anchor point for the forecast
2. Local historical/transfer/addition information for substations
3. Regional economic and demographic information

To appropriately represent these elements a series of forecasts are developed.

The first stage starts with a preparing two bottom up forecasts each focused on capturing relevant local and regional information and results in the distribution substation forecast and the distribution peak guideline forecast respectively. These two forecasts are then averaged and the average is aggregrated to form the regional distribution peaks for each of four service areas. Each of these bottom up forecasts is based off a weather normalized peak anchor point derived at the substation level.

Because of the data challenges of developing a weather normalized peak anchor point at the substation level a further top down estimate of the weather normalized peak anchor point is developed at the system and regional level based, on hourly load data. With this top down estimate of the anchor point, a regional distribution forecast is prepared and compared to the bottom up forecast. To finalize the peak forecasts, a blended weather normalized anchor point is developed.

Each of these steps is outlined in figure 11.1, which shows the peak forecasting method and the various intermediate steps to develop the final forecast. Each of these steps is discussed below. The methodology underlying the top down estimate of the weather-normalized peak is provided in Appendix 4. The series of steps work to reduce any forecast risk or bias in each of the individual forecasts.

In summary the peak forecast process starts at the substation level with a locally based forecast that captures, historic growth rates, load transfer and information from planners on new discrete load additions at the substation level. This substation forecast is compared to a regionally based guideline forecast that evaluates key economic and demographic information within 12 distribution planning regions: Vancouver Island North, Central, South; South Interior, North Regional and seven Lower Mainland areas. This regionally based econometric forecast is driven by four primary factors: (1) economic forecasts (2) electric space heating forecasts, (3) short term forecasts of account additions and (4) weather normalized peak load of each substation. This regional econometric forecast provides a guideline for expected growth that is compared to the locally based substation forecast as the basis to establish the forecast for the distribution peak. In particular, the substation and guideline forecast are averaged and aggregated into four regional distribution peak forecasts for each of the service areas of Lower Mainland, Northern Region, South Interior and Vancouver Island. At this point, the weather normalized anchor point implied in this averaged forecast is compared to the top down weather normalized information, yielding the final weather normalized anchor point from which the final distribution peak forecast is prepared.

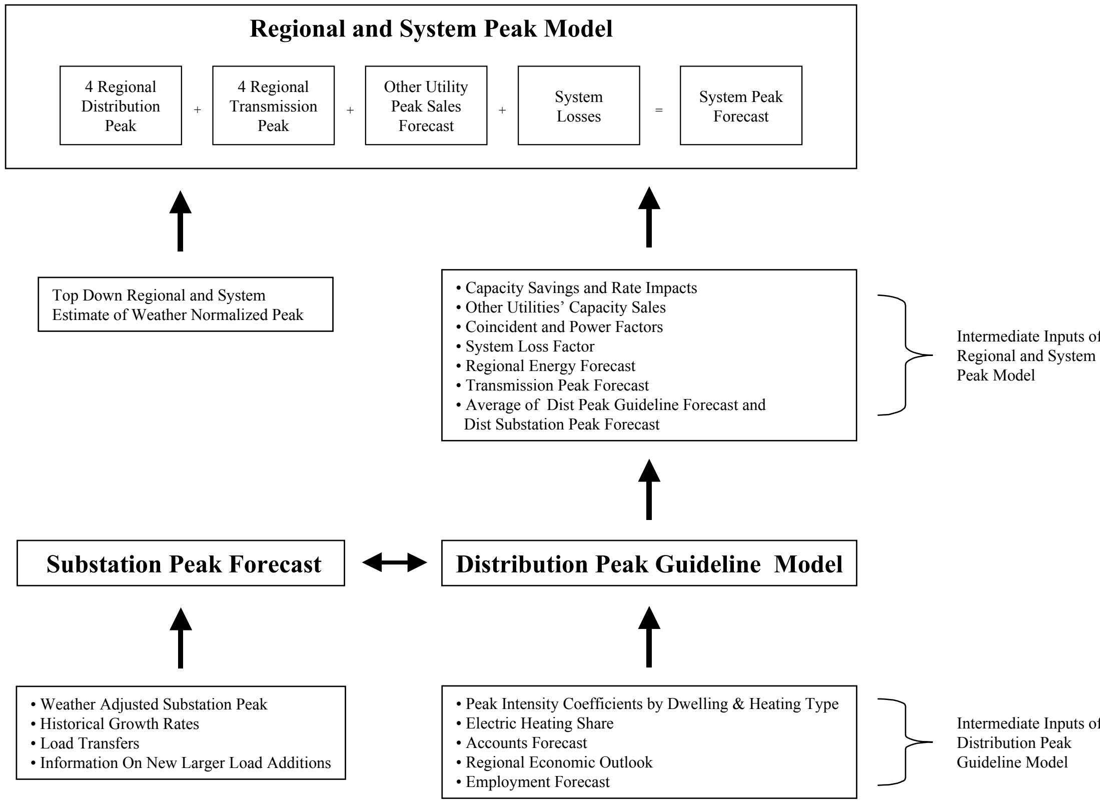
The next step is to add the regional distribution peak forecast with the regional transmission peak forecast, wholsale peak sales and system losses to provide the total regional and system peak forecasts. Coincidence factors are applied to account for load diversity (i.e. differences in the timing of distribution substation and transmission customer peaks relative to the aggregate regional peak). The coincidence factors are based on analyses of historical data. Included in the regional distribution peak forecast are distribution losses because the forecasts are prepared at the substation level and represent the sum of regional substation peaks. The model produces the regional distribution, transmission and system peak forecasts before and with Power Smart. The capacity savings are provided as input into the forecast by Power Smart.

In the short term, transmission load forecasts are developed on customer-by-customer basis for BC Hydro’s transmission voltage customers. These customer forecasts are developed from sector reports, industry information and customer specific information on operations and plans. Medium to longer-term transmission peak forecasts are based the results of the econometric energy model and assuming a constant load factor.

Inter-utility capacity sales and firm capacity exports are included in the regional and system peak forecasts at the point of sale.

The BC Hydro integrated system peak forecast is the coincident sum of the four total regional peak forecasts, plus a forecast of the total transmission losses at the time of the system peak. The assumed inter-regional coincidence factors and transmission loss factors are based on historical data.

Figure 11.1. Peak Forecast Method Overview



11.2.1. Distribution Peak Forecasts

At the distribution level, electricity demand is closely linked to the forecast of the local economy, as well the historical trends of distribution load growth. As such, regional economic outlooks are one of the primary inputs into distribution peak demand forecasts. BC Hydro obtains economic forecasts from B.C. Statistics, external consultants and the Greater Vancouver Regional District. Another input into the distribution peak forecasts is the historic weather-normalized substation peak, which is prepared by BC Hydro Distribution Planning. BC Hydro's regional and system distribution peak forecasts incorporate distribution peak forecasts from various models used within BC Hydro as means to reduce forecast risk.

Distribution Peak Guideline Model (Economteric Model)

As described in the peak forecast method overview, the distribution peak forecast for each region begins with preparing the 11-year distribution peak guideline forecast for 12 planning areas. The distribution peak guideline forecast is prepared using an econometric model and is a guideline of the growth in the non-coincident substation peak (MVA) load for each of the 12 areas.

The basic framework of the forecast is given by:

(11.1) Peak = Stock X Electric Intensity per unit of Stock

The two main drivers of the stock forecast are the forecasts of employment and growth in the number of residential customer accounts. The accounts forecast is used to develop the residential sales forecast and the employment forecast is based on the regional economic outlook, as provided by consultant reports.

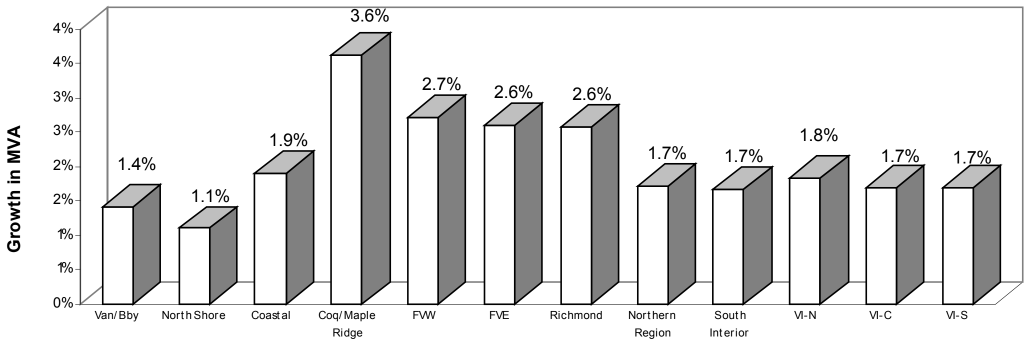
The forecast of electric intensity per unit of stock is in the form of electric peak per unit of housing (kW per account) and electric peak per unit of sales to the general rate class (kW per kWh).

The model is calibrated to ensure that the coefficients accurately track past metered substation peaks. This is accomplished by 'back-casting', that is, by comparing actual substation peak data with the peak estimated by multiplying the historical number of accounts (and general class energy), from the billing records and the intensity coefficients.

To develop the forecast, the model also requires the weather-normalized substation peak for the previous fiscal year for each of the 12 planning areas. These values represent the base year data for the model. Distribution planning provides the weather-adjusted substation peaks for each substation. Their weather-adjusted peak for each substation is based a linear regression technique involving metered substation peak and weather data closest to each substation. With the base year data (weather-adjusted peak) loaded into the model, the drivers and the calibrated intensity coefficients combine to predict the growth rate of the substation peak for the next 11 years. Figure 11.2 shows the average annual growth rates of the 12 distribution planning areas of the distribution peak guideline forecast before Power Smart.

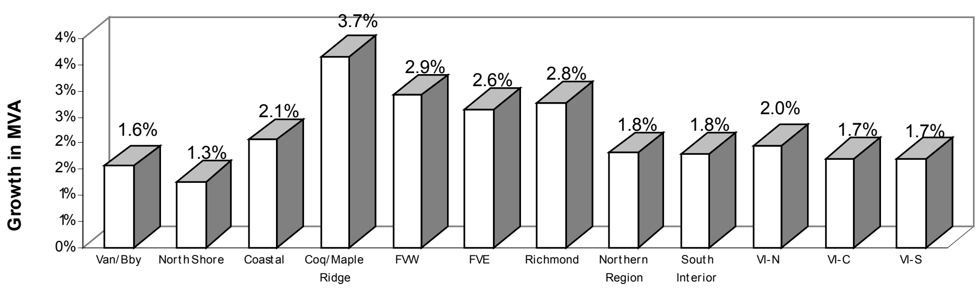
The distribution peak guideline forecast is provided to Distribution Planning so that a long-term substation peak forecast can be produced. The substation peak forecast also considers drives such as the historical growth rates of each substation, load transfers between substations and information from planners on larger load additions such as shopping malls, resorts or hotels. Figure 11.3 shows the average annual growth rate of the substation peak forecast in each planning area.

Figure 11.2. Distribution Peak Guideline Forecast Before Power Smart – Average Annual MVA Growth (2002/03 to 2012/13)



Notes:
1. Coastal includes Squamish, Whistler, Sunshine Coast and Powell River.
2. Fraser Valley West includes Richmond, Delta, Surrey and Langley.
3. VI-S is Vancouver Island South, VI - C is Vancouver Island Central which includes Gulf Islands and VI - N is Vancouver Island North.
4. MVA – Megavolt-Amps, the units of apparent power. See Glossary.

Figure 11.3. Distribution Substation Peak Forecast Before Power Smart – Average Annual MVA Growth (2002/03 to 2012/13)



Notes:
1. Coastal includes Squamish, Whistler, Sunshine Coast and Powell River.
2. Fraser Valley West includes Richmond, Delta, Surrey and Langley.
3. VI-S is Vancouver Island South, VI - C is Vancouver Island Central which includes Gulf Islands and VI - N is Vancouver Island North.
4. MVA – Megavolt-Amps, the units of apparent power. See Glossary.

Regional Distribution Peak Forecast

BC Hydro forecasts a peak for each the four major regions of Vancouver Island, Lower Mainland, Northern Region and South Interior. The regional distribution peak forecast for each major region is based on an average of the distribution guideline peak forecast and the non-coincident substation peak forecast prepared by Distribution Planning. The substation peak forecast focuses on drivers such as large load additions in preparing the peak forecast for each substation. The peak guideline forecast uses economic drivers of load to develop a total substation peak for each planning area.

To prepare regional distribution peak forecasts, BC Hydro uses an average of both forecasts to reduce the forecast risk of relying upon one particular approach. The average and aggregation of both forecasts into four regions from 12 planning areas are combined with estimates of power factors and coincident factors in the regional and system peak model to produce a coincident distribution peak forecast (MW) for each of the major regions. Distribution capacity savings as provided by Power Smart are also incorporated in the regional and system peak model to produce a coincident distribution peak forecast with Power Smart.

Table 11.1 shows the non-coincident and coincident distribution peak forecast before Power Smart for each region. The first 11 years of the forecast is based on the average of the two peak forecasts. The second 10 years of the peak forecast is derived, based on the growth rate in distribution energy sales in each of the four major service regions.

Table 11.1. Regional Non-Coincident and Coincident Distribution Peaks Forecast Before Power Smart

	Lower Mainland		**Vancouver Island**		**South Interior**		**Northern Region**	
	Non-Coinc. Peak (MVA)	**Coinc. Peak (MW)**	**Non-Coinc. Peak (MVA)**	**Coinc. Peak (MW)**	**Non-Coinc. Peak (MVA)**	**Coinc. Peak (MW)**	**Non-Coinc. Peak (MVA)**	**Coinc. Peak (MW)**
Actual								
2002/03	3911	3838	1583	1407	846	731	666	570
Weather-Adjusted Actual								
2002/03	4074	3660	1688	1554	856	772	689	615
Forecast (Weather-Normalized)								
2003/04	4202	3775	1736	1598	888	801	723	645
2004/05	4309	3871	1766	1626	901	813	732	654
2005/06	4411	3963	1797	1655	915	826	743	664
2006/07	4510	4051	1828	1683	931	840	756	675
2007/08	4611	4142	1861	1713	947	854	768	686
2008/09	4714	4235	1892	1742	964	869	780	697
2009/10	4815	4326	1923	1770	980	884	792	707
2010/11	4907	4408	1953	1798	996	899	804	718
2011/12	5004	4495	1983	1826	1013	914	815	728
2012/13	5097	4579	2013	1853	1030	929	826	738
2013/14	5191	4663	2042	1880	1046	944	837	748
2014/15	5281	4744	2081	1916	1069	965	851	760
2015/16	5370	4824	2119	1951	1092	986	865	772
2016/17	5460	4905	2157	1986	1116	1006	879	785
2017/18	5549	4985	2195	2021	1139	1027	893	797
2018/19	5639	5066	2233	2056	1162	1048	907	810
2019/20	5729	5146	2271	2091	1185	1069	921	822
2020/21	5818	5227	2309	2126	1208	1090	935	835
2021/22	5908	5307	2348	2161	1231	1110	949	847
2022/23	5997	5388	2386	2197	1254	1131	963	860
2023/24	6087	5468	2424	2232	1277	1152	977	872
Growth Rates								
5 years 02/03 to 07/08	2.5%	2.5%	2.0%	2.0%	2.0%	2.0%	2.2%	2.2%
10 years 02/03 to 12/13	2.3%	2.3%	1.8%	1.8%	1.9%	1.9%	1.8%	1.8%
last 11 years 12/13 to 23/24	1.6%	1.6%	1.7%	1.7%	2.0%	2.0%	1.5%	1.5%

Notes:

1. Distribution peak forecast based on average of Substation forecast and Distribution Peak Guideline Forecast.
2. Growth rates based on weather adjusted peaks.

11.2.2 Transmission Peak Forecasts

In the short term (over the first four years), the transmission peak forecast is prepared on a customer-by-customer basis. Information from BC Hydro's key account managers, historical billing trends and consultant reports on major industries are some of inputs that are used to establish the short-term transmission account forecast.

In the medium and longer term, the transmission sales forecast is prepared using an econometric approach. Transmission energy consumption levels are analyzed in relation to provincial GDP forecasts to establish the forecast trend for the medium to long term. Assuming a constant load factor, the transmission peak forecast for industry is developed based on the energy regression analysis over years five to eleven.

For the last 10 years of the forecast period, the peak forecast for each region is derived using the growth rate in the transmission energy forecast in each region. Table 11.2 shows the transmission peak forecast before Power Smart for each region.

Table 11.2. Regional Transmission Peak Forecast Before Power Smart

	Lower Mainland	**Vancouver Island**	**South Interior**	**Northern Region**
	Peak (MW)	**Peak (MW)**	**Peak (MW)**	**Peak (MW)**
Actual				
2002/03	450	493	252	737
Forecast				
2003/04	419	439	250	735
2004/05	418	439	247	743
2005/06	420	439	247	748
2006/07	420	438	247	751
2007/08	435	456	205	787
2008/09	439	456	206	793
2009/10	444	476	168	827
2010/11	438	482	170	838
2011/12	440	485	171	843
2012/13	442	488	172	848
2013/14	445	488	173	852
2014/15	447	492	175	858
2015/16	450	495	177	864
2016/17	453	499	178	870
2017/18	455	503	180	876
2018/19	458	506	182	883
2019/20	461	510	184	889
2020/21	464	514	185	895
2021/22	466	518	187	901
2022/23	469	521	189	907
2023/24	472	525	191	913
Growth Rates				
5 years 02/03 to 07/08	-0.7%	-1.5%	-4.1%	1.3%
10 years 02/03 to 12/13	-0.2%	-0.1%	-3.7%	1.4%
last 11 years 12/13 to 23/24	0.6%	0.7%	0.9%	0.7%

11.3 Weather Normalization and Peak Forecast

As stated above, BC Hydro's regional distribution peak is the average of two forecasts: the distribution peak guideline forecast and the substation peak forecast. Both of these forecasts rely upon the previous year's weather-normalized (or adjusted) total substation peak load in each of the 12 planning areas.

The weather-normalized substation peak for each substation in the BC Hydro integrated system is based on a weather-normalization procedure from Distribution Planning. This procedure uses a linear regression of winter-metered substation peak load on temperature readings from the weather station closest to each substation. After the regression is completed, a normalized peak for each substation is computed, based on an average mean cold temperature, which is defined as the average of the lowest daily average temperature over the past 30 years.

Difficulties, however, hamper a weather-normalized peak from being determined for each substation. These difficulties are related to the recent milder weather conditions, load transfers between stations and load fluctuations in industrial distribution, which impact the recorded peaks.

As a result of these challenges, BC Hydro has also employed a top-down approach to determining the weather-adjusted peak, which uses hourly load data as opposed to substation-metered data to determine the weather-normalized peak. The top-down approach uses hourly total load data and a weather-normalization procedure based on a cubic regression equation as a means to determine the weather-adjusted peak for the total system and for Vancouver Island. The hourly load data is input into a cubic peak-forecasting model, which incorporates temperature, type of day (weekday, weekend, holiday), daylight hours and a trend variable to explain the variation in the daily peak load. The procedure of developing a weather-normalized total peak for the system and Vancouver Island is described in Appendix 4.

The weather-adjusted peak for Vancouver Island and the system peak, as determined by the top-down approach, are used as a means to validate and reconcile growth rates for the distribution peak and total system peak. The process of reconciling growth rates from the two approaches to weather normalization occurs in the regional and system peak model. The weather-adjusted peak based on the substation bottom-up approach yields one view of growth rates and peak forecasts. Alternatively, using the approach as described Appendix 4 yields a different set of growth rates and forecast of the distribution peak. Growth rates and forecasts from these two approaches are also compared with energy growth rates and other methods such as a load factor approach to develop a peak forecast. The analysis results in the distribution peak forecast used in establishing the total system peak forecast.

Table 11.3 shows the total weather-adjusted peak as determined by the bottom-up approach as the aggregation of each substation's weather-adjusted peak, and the weather-adjusted peak used to develop the December 2003 forecast.

Table 11.3. Fiscal 2002/03 Regional and Total Actual and Weather-Adjusted Non-Coincident Distribution Peak

	Actual		**Bottom-Up Substation Weather-Adjusted Peak**		**Weather-Adjusted Base Year for Forecast***	
	MVA	MW	MVA	MW	MVA	MW
	Non-Coin.	Coin.	Non-Coin.	Coin.	Non-Coin	Coin
Lower Mainland	3,911	3,383	4,004	3,579	4,074	3,660
Vancouver Island	1,583	1,407	1,672	1,540	1,688	1,554
South Interior	846	731	841	759	856	772
Northern Region	666	570	676	603	689	615
Distribution Peak Total(1)	7,006	5,923	7,193	6,389	7,307	6,490
Transmission Peak Total (2)		1,890		1,896		1,896
Losses (3)		648		687		696
Domestic System Peak		8,461		8,972		9,082

* Used to develop December 2003 Forecast

Notes:

1. Total Regional distribution peak is less than the sum of each Regional peak because regional distribution peaks occur at different time relative to system's distribution peak.
2. Transmission Peak includes peak requirements for City of New Westminster
3. Losses are not computed on a non-coincident MVA basis but are computed on a total system coincident basis, as such only the total system coincident peak is provided.

11.4 Total Regional Peak and System Peak Forecast

As previously stated, BC Hydro calculates a regional peak forecast for the regions of Lower Mainland, Vancouver Island, Northern Region and South Interior. The peak forecast in each region is equal to the coincident sum of the regional distribution and transmission peak and applicable wholesale peak loads. In any region, the total regional peak is:

(11.2) $\text{Regional Peak}_{(t)} = \text{Regional Transmission Peak}_{t} + \text{Regional Distribution Peak}_{t} + \text{Wholesale Peak}_{t}$

The regional peak forecast and system peak forecast is developed using BC Hydro's regional and system peak forecast model. The model also incorporates capacity savings, as provided by Power Smart. The total regional peak forecast includes distribution losses because the distribution peak forecast is prepared at the substation level. Transmission losses are only included at the total system peak forecast. Unlike the other regions, the Vancouver Island peak forecast is also prepared by including transmission losses. The transmission line losses percentages for Vancouver Island and the system are based on studies from transmission planners.

BC Hydro's system peak forecast is the coincident sum of the four regional distribution and transmission peak forecasts, plus wholesale peak load, plus the total transmission losses at the time of the system peak. The sum is calculated in the regional and system peak model using inter-regional coincident factors, which are applied to regional distribution, transmission and wholesale peaks. These coincident factors are based on historic load data and account for load diversity (differences in the timing the regional distribution and transmission peaks relative to the system's total distribution and transmission peaks).

Tables 11.4 and 11.5 show the 2003/04 regional and system peak forecast before and with Power Smart.

Table 11.4. Domestic System and Regional Peak Forecast Before Power Smart

	Lower Mainland	Vancouver Island	Southern Interior	Northern Region	Transmission Losses >60 kV	Domestic System
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
Actual						
2002/03	4013	1900	1209	1307	616	8461
Weather-Adjusted Actual						
2002/03	4309	2048	1205	1352	661	9082
Forecast						
2003/04	4391	2037	1232	1381	710	9339
2004/05	4487	2066	1241	1398	722	9500
2005/06	4581	2094	1258	1413	734	9662
2006/07	4671	2122	1275	1427	746	9818
2007/08	4778	2169	1251	1473	760	10004
2008/09	4877	2198	1272	1490	773	10176
2009/10	4972	2246	1248	1535	787	10355
2010/11	5050	2281	1265	1556	799	10515
2011/12	5141	2311	1281	1571	811	10678
2012/13	5228	2341	1297	1586	823	10836
2013/14	5315	2368	1313	1601	835	10992
2014/15	5399	2407	1336	1619	849	11167
2015/16	5483	2446	1358	1638	862	11343
2016/17	5568	2485	1381	1656	875	11518
2017/18	5652	2524	1403	1675	889	11693
2018/19	5736	2563	1426	1693	902	11868
2019/20	5820	2601	1448	1712	915	12044
2020/21	5905	2640	1471	1730	929	12219
2021/22	5989	2679	1494	1749	942	12394
2022/23	6073	2718	1516	1767	955	12569
2023/24	6157	2757	1539	1786	969	12745
Growth Rates						
5 years 02/03 to 07/08	2.1%	1.2%	0.8%	1.7%	2.8%	2.0%
10 years 02/03 to 12/13	2.0%	1.3%	0.7%	1.6%	2.2%	1.8%
last 11 years 12/13 to 23/24	1.5%	1.5%	1.6%	1.1%	1.5%	1.5%

Notes:

1. Regional peak includes distribution losses but not transmission losses.
2. The domestic system peak is less than the sum of the regional peaks plus transmission losses because regional peaks occur at different times.

3. Lower Mainland peak includes sales to City of New Westminster and firm exports to Seattle City Light.
4. Southern Interior includes sales to Aquila Networks Canada.
5. Northern Peak includes integrated system only.
6. Actual peaks are not weather-normalized and peak forecast values are weather-normalized.
7. Growth rates are based on weather-adjusted peaks.

Table 11.5. Domestic System and Regional Peak Forecast With Power Smart

	Lower Mainland (MW)	Vancouver Island (MW)	Southern Interior (MW)	Northern Region (MW)	Transmission Losses >60 kV (MW)	Domestic System (MW)
Actual						
2002/03	4013	1900	1209	1307	616	8461
Weather-Adjusted Actual						
2002/03	4309	2048	1205	1352	661	9082
Forecast						
2003/04	4375	2030	1226	1371	707	9298
2004/05	4436	2046	1223	1358	712	9364
2005/06	4501	2059	1234	1363	719	9460
2006/07	4560	2068	1246	1371	726	9551
2007/08	4646	2103	1220	1403	736	9683
2008/09	4727	2120	1235	1406	745	9806
2009/10	4806	2156	1212	1436	755	9935
2010/11	4866	2178	1225	1445	763	10046
2011/12	4941	2198	1236	1449	772	10164
2012/13	5028	2228	1252	1463	784	10322
2013/14	5115	2255	1268	1478	796	10478
2014/15	5199	2294	1291	1496	810	10653
2015/16	5283	2333	1314	1515	823	10828
2016/17	5368	2372	1336	1533	836	11003
2017/18	5452	2410	1359	1552	849	11179
2018/19	5536	2449	1381	1570	863	11354
2019/20	5620	2488	1404	1589	876	11529
2020/21	5705	2527	1426	1607	889	11704
2021/22	5789	2566	1449	1626	903	11880
2022/23	5873	2604	1471	1644	916	12055
2023/24	5957	2643	1494	1663	929	12230
Growth Rates						
5 years 02/03 to 07/08	1.5%	0.5%	0.2%	0.7%	2.2%	1.3%
10 years 02/03 to 12/13	1.6%	0.8%	0.4%	0.8%	1.7%	1.3%
11 years 12/13 to 23/24	1.6%	1.6%	1.6%	1.2%	1.6%	1.6%

Notes:

1. Regional peak includes distribution losses but not transmission losses.
2. The domestic system peak is less than the sum of the regional peaks plus transmission losses because regional peaks occur at different times.
3. Lower Mainland peak includes sales to City of New Westminster and firm exports to Seattle City Light.
4. Southern Interior includes sales to Aquila Networks Canada.
5. Northern Peak includes integrated system only.
6. Actual peaks are not weather-normalized and peak forecast values are weather-normalized.
7. Growth rates are based on weather-adjusted peaks.

11.4.1. 2003/04 Peak Forecasts

The December 2003 peak forecast is explained by examining the 2002/03 peak, the key drivers of the peak forecasts, and the individual components, which make up the forecast.

During the 2002/03 winter, the total domestic system peak was 8,461 MW, which occurred on December 18, 2002, at daily average temperature of 5.3 degrees Celsius. BC Hydro's weather-adjusted peak for 2002/03 is 9,082 MW. This compares to the weather-adjusted peak of 9,016 MW for 2001/02, as the peak grew by 65 MW or 0.7 per cent.

The forecast of the total system peak before Power Smart for 2003/04 is 9,339 MW and 9,298 MW with Power Smart. The peak is expected to grow by 257 MW or 2.8 per cent before Power Smart and 216 MW or 2.3 per cent with Power Smart. This year's growth in the peak is disaggregated into the various peak forecasts that make up the system peak, as shown in Table 11.6.

Table 11.6. Actual and Weather-Adjusted and Peak Forecasts Before Power Smart

	Distribution		Transmission	Domestic System Peak	
	Actual Peak	Weather-Adjusted Peak	Peak	Actual Peak	Weather-Adjusted Peak
	MW	MW	MW	MW	MW
Actual					
2001/02	6200	6505	1751	8674	9016
2002/03	5923	6490	1819	8461	9082
Forecast					
2003/04		6704	1814		9339
2004/05		6847	1818		9500
2005/06		6988	1824		9662
2006/07		7128	1827		9818
2007/08		7272	1853		10004
2008/09		7418	1864		10176
2009/10		7560	1886		10355
2010/11		7694	1898		10515
2011/12		7832	1909		10678
2012/13		7966	1920		10836
2013/14		8100	1928		10992
2014/15		8246	1941		11167
2015/16		8393	1955		11343
2016/17		8539	1969		11518
2017/18		8685	1983		11693
2018/19		8831	1997		11868
2019/20		8978	2011		12044
2020/21		9124	2025		12219
2021/22		9270	2039		12394
2022/23		9417	2053		12569
2023/24		9563	2067		12745
Growth Rates					
5 years 02/03 to 07/08		2.3%	0.4%		2.0%
10 years 02/03 to 12/13		2.1%	0.5%		1.8%
11 years 12/13 to 23/24		1.7%	0.7%		1.5%

11.4.2. Transmission Total Peak Forecast

From Table 11.6, the forecast of the transmission peak for the winter of 2003/04 is expected to be very similar to the forecast for 2001/02. The increase in the 2002 transmission forecast can be explained by natural gas prices. In 2002, higher natural gas prices seem to have affected transmission sales to customers with self-generation. As result, some customers with fuel switching capabilities purchased additional power. Other explanations for the higher peak for 2002/03 are related to reaction of some sawmills in response to the countervailing and anti-dumping softwood lumber duties. Some larger mills increased their production levels and hence their power demands as means to lower the unit costs and absorb the additional costs of the duties.

The medium- to longer-term forecast reflects an anticipated modest recovery in B.C.'s economy and the major industrial sectors. This is reflected in the medium- to long-term forecast.

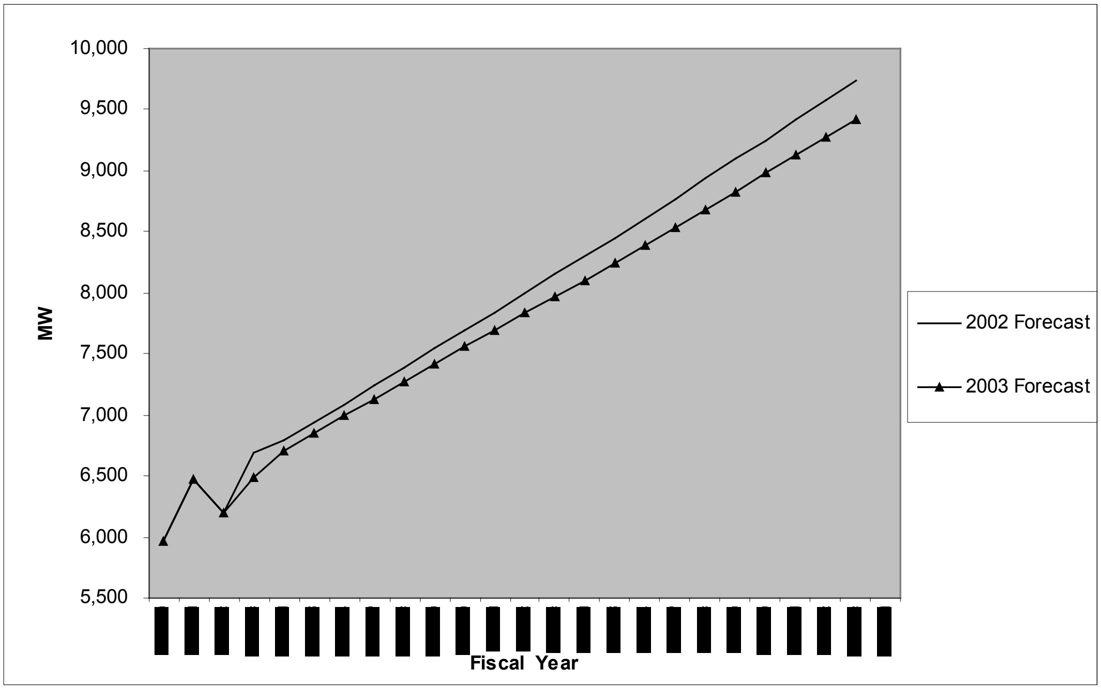
11.4.3. Distribution Total Peak Forecast

Compared to 2001/02, the total distribution peak in 2002/03 declined by 277 MW or 4.4 per cent before weather adjustments and by 15 MW or 0.23 per cent including weather adjustments. The decline in the distribution peak over 2001/02 and 2002/03 is related to a number of factors including the impact of the softwood lumber dispute on some of the smaller mills at the distribution level.

For 2003/04, the total distribution peak before Power Smart is expected to grow by 214 MW or 3.2 per cent. The base year for the 2003 forecast (2002/03) is lower on an actual and weather-adjusted basis compared to the 2001/02 weather-adjusted peak. As such, some the growth in the peak can be viewed as a recovery and not growth in new or existing load. Despite the decline in the peak, the growth in 2003/04 also reflects a substation load transfer of approximately 30 MVA in the North Region. The 2003 forecast of growth also reflects anticipated stronger growth in the peak demands of residential customers. Lower interest rates have continued to fuel housing demand in many parts of British Columbia.

The 2003 peak forecast is below the 2002 forecast. Figure 11.4 compares the 2003 distribution peak forecast and the 2002 forecast. The 2003 forecast is below the 2002 forecast because of the decline in the base year as well as decline in the drivers of the forecast. As indicated earlier, the total distribution peak for BC Hydro reflects the forecast of substation growth and the forecast generated by the distribution peak guideline model. The growth in the peak reflects regional economic drivers of the forecast. The drivers of the distribution peak, such as the population and employment forecast, which affects the general sector's contribution to the peak, are below 2002/03. This has contributed to a pushing out of the peak forecast.

Figure 11.4. Total Distribution Peak Before Power Smart Comparison



12 Power Smart and the Conservation Potential Review Study

12.1. Conservation Potential Review

BC Hydro made a significant investment in conservation through its Power Smart program in the 1989 to1997 period. Investments of this type are made by utilities to defer capital investments in distribution and transmission infrastructure, and to defer the need to build generation or purchase power. Investments by the utility and its customers are made in energy-efficient equipment and process improvements where both the utility ratepayers and the customers are better off in the long term. The first phase of Power Smart resulted in energy savings by 1998/99 of approximately 2,500 GWh per year.

During the early years of Power Smart, a Conservation Potential Review (CPR, 1994) was undertaken to assess the potential for electricity savings under various scenarios. As the current phase of Power Smart was ramping up, plans were based on outputs from the first CPR, and the experience and results of the first decade of investment. A second CPR was commissioned and was completed in 2003. The study had the following objectives:

- To provide BC Hydro's Power Smart program planners with an updated assessment of the remaining electricity efficiency potential in B.C. as a basis for designing new initiatives or rates;
- To estimate the potential contribution of Power Smart efficiency programs to the reduction of BC Hydro's peak capacity requirements; and
- To identify additional technologies that could be "fast tracked" to provide further savings over the study period.

The Review confirms that significant cost-effective electricity efficiency improvements do exist in every sector in BC Hydro's service area. Table 12.1 summarizes the total energy savings potential under the conditions defined in the study as "Economic" and "Achievable," as compared with the Reference Case. Table 12.2 summarizes the demand implications of the projections.

Table 12.1 Forecast Summary – Total BC Hydro Service Area Annual Electricity Consumption and Potential Savings*

Annual Electricity Consumption (GWh per year) All Sectors						Potential Annual Savings (GWh per year)		
	Base Year	Reference Case	Economic	Achievable		Economic	Achievable	
				Most Likely	Upper		Most Likely	Upper
2000/01	47,521	47,521						
2005/06		49,739	42,513	48,509	47,652	7,226	1,231	2,087
2010/11		52,663	41,856	49,208	47,406	10,807	3,455	5,257
2015/16		54,729	42,267	48,894	46,507	12,462	5,835	8,222

* Line losses are not included.

Table 12.2. Forecast Summary – Total BC Hydro Service Area Demand Implications of Economic and Achievable Forecasts*

(High-demand period, winter weekdays from 6 AM to 10 PM, December and January)

	Average On-peak Demand (MW) All Sectors					**Potential On-peak Demand Savings (MW)**		
	Base Year	Reference Case	Economic	Achievable		Economic	Achievable	
				Most Likely	Upper		Most Likely	Upper
2000/01	4,912	7,146						
2005/06		7,522	6,400	7,345	7,220	1,122	177	302
2010/11		7,982	6,349	7,491	7,228	1,633	491	754
2015/16		8,342	6,462	7,501	7,138	1,880	841	1,204

* Includes line losses at seven per cent. (This includes distribution losses of four per cent and area transmission losses of three per cent).

12.2. Power Smart 10-Year Plan

Power Smart was launched by BC Hydro in 1989/90 with the primary aim of achieving significant energy savings from existing and new customers, thus deferring the need for new generation supply.

By 2000, Power Smart yielded 2,500 GWh per year in energy savings at a cost of $338.4 million. These savings are equivalent to meeting the energy needs of a community the size of Surrey (250,000 homes), and deferring the need for 500 MW of generation. Over 700,000 customers have participated in Power Smart thus far, resulting in savings of more than $1.1 billion on their electricity bills. Savings have also resulted in the reduction and/or avoidance of more than 1.25 million tonnes of greenhouse gases per year.

The provincial government in its 2002 energy policy clearly elevates the importance of conservation and energy efficiency in the context of meeting B.C.'s future energy needs. Power Smart is again well positioned to play a strategic role in BC Hydro's continuing efforts to deliver competitive integrated energy solutions to its customers in an environmentally and socially responsible manner.

12.2.1. 10-Year Power Smart Plan

Based on the process and the outputs from the 2002 Conservation Potential Review, a Power Smart 10-Year Plan was developed, refining the investment strategy both in the area of sector focus and timing of the savings. The recent first 18 months of experience in operating current programs, combined with the experience in the previous programs, also contributed to the plan, which details the investment strategy from 2001/02 to 2011/12.

The savings targets/forecast in the 10-year plan are somewhat lower than the achievable forecast from the CPR. This is due to the desire to balance investment dollars and timing, along with the fact that the resultant program level plans add more knowledge to the estimates from the CPR process. The 10-Year target for Power Smart is to save 3,618 GWh per year by the year

2011/12. The 2003 Electric Load Forecast starts with year-end billing data for 2002/03, which includes the results of all Power Smart investments prior to that date. As a result, Power Smart savings estimate seen in this and any future load forecast will show future effects less than the 10-year target as more and more of the effects are built into the forecast starting point.

The plan also addresses some fuel switching initiatives that are cost-effective. Vancouver Island has an increasing peak capacity issue, which is exacerbated by the fact that a high proportion of residential customers are choosing electric space heating, even when natural gas is available. A number of small fuel-switching initiatives are being examined and are included in the plan. A complete inventory of the fuel-switching potential is not available, but some preliminary estimates are included as a component of the plan. Fuel switching initiatives will be broken out by application, type of fuel and efficiency of conversion, and will identify the net impact on greenhouse gas emissions, but they only represent about five per cent of the total Power Smart portfolio.

Load displacement initiatives are considered “Clean” (as defined in the B.C. Energy Plan) as they are expected to use biomass fuel. Fuel switching initiatives included in the plan meet all appropriate cost effectiveness tests and take into account the full life-cycle electric and gas costs.

12.2.2. Base Case Savings

This 10-year plan has been developed by drawing on the market intelligence contained in the CPR, plus other opportunities that were outside of the scope of the CPR. The 10-year plan’s base case energy savings target (at the customers’ meter, net of free riders, free drivers, and measurement and verification allowances) is 3,618 GWh per year by 2011/12, and requires an investment of $690.6 million. This yields a cost-effective levelized utility cost and a total resource cost of $0.021/kWh and $0.044/kWh respectively. The customer bill savings resulting from the electricity savings identified in this plan is calculated at $2.28 billion at current electricity rates.

Approximately 59 per cent of the 10-year energy savings target comes from the industrial sector, compared to 21 per cent from government and other commercial, and 20 per cent from residential.

Several factors outside of BC Hydro’s control could have an impact on the actual energy savings that are achieved. For example, with 59 per cent of the total 10-year energy savings coming from the industrial sector, the plan is very dependent on stability in that sector.

Issues such as softwood lumber tariffs or the general health of the economy could have significant impacts on the industrial sector’s participation, and hence on the overall 10-year target. Further, a heavy dependence on market transformation in terms of its percentage of the 10-year target would make the plan more risky. Finally, overall market penetration assumptions surrounding direct energy acquisition are by no means certain.

12.2.3. Mitigation of Risks

Because there are risks in preparing this plan, a number of steps have been taken to mitigate these risks and lessen their impacts. First, the plan has been assembled to minimize dependence on market transformation. Only seven per cent of the 3,618 GWh per year target is related to market transformation.

Second, in order to reflect the risks and uncertainties characteristic of the base case target, a range has been developed within which the actual 10-year energy savings are expected to result. The upper end of the range is approximately 4,225 GWh per year (at an investment of $739.5 million) whereas the lower end is approximately 3,011 GWh per year (at an investment of $618.6 million). Importantly, the plan passes all cost-effectiveness tests under both the low and high scenarios.

Third, it is important to emphasize that the upper and lower ends of the range do not represent a "best case" / "worst case" view. Given that the market penetration assumptions characteristic of this range are largely linked to the "most likely" achievable potential scenario from the Conservation Potential Review, there is additional upside potential which could generate a "best case" that is higher than the upper scenario. Conversely, should major events transpire during the planning period which adversely affect consumer confidence or the overall economy, thus triggering a major recession, then the true "worst case" could be significantly worse than the lower scenario.

12.2.4. 10-Year Plan Allocation

In order to achieve the base case energy savings target of 3,618 GWh per year, a 10-year portfolio investment of $690.6 million is required, and allocated as follows:

- 39 per cent, or $265.6 million, is invested in the industrial sector to capture load displacement and various demand-side managment opportunities, largely through the Power Smart Partners program.
- 25 per cent, or $171.9 million, is invested in the government and other commercial sectors in pursuit of opportunities related to lighting and other end uses through existing and new programs such as Power Smart Partners, SUCH, Power Smart Express and New Construction.
- 16 per cent, or $112.4 million, is invested in the residential sector, in pursuit of opportunities related to lighting, appliances and home envelope through new and existing programs such as compact fluorescent lighting (CFL), Refrigerator Buy-back, Home Energy Upgrade, Power Smart New Home and various fuel switching initiatives.
- Eight per cent, or $52.4 million, is invested in public education and non-program specific communications with customers
- 12 per cent, or approximately $88.3 million, is invested in various enabling costs, overheads, administration and management.

13 Glossary

Coincidence Factor A ratio reflecting the relative magnitude of a region's (or customer's or group of customers') demand at the time of the system's maximum peak demand to the region's (or customer's or group of customers') maximum peak demand.

Consumer Price Index (CPI) An inflation index calculated by comparing the price of a typical bundle of goods in the year in question to the price of the same goods in a set reference year.

Demand-Side Management (DSM) The influencing of energy demand to achieve socially economic efficiency improvements in the end use of electricity, and to shift electricity demand to reduce utility capacity costs.

Region A geographical sub-division of the BC Hydro service area. Four regions exist: Lower Mainland, Vancouver Island, South Interior and the Northern Region.

Distribution voltage customer A BC Hydro customer who receives electricity via distribution lines that operate at relatively low voltage (34 kV and less).

Diversity That quality or characteristic by which individual maximum demands occur at different times. Diversity may be examined on an hourly, daily, monthly or yearly basis.

Econometric modelling The use of statistical techniques, typically regression analysis of time-series and/or cross-sectional data, to detect statistically verifiable relationships, coherent with economic theory, between an explained variable (e.g. electricity consumption) and explanatory variables (e.g. industry output, prices of alternative energy inputs and GDP).

Elasticity The proportionate change in a dependent variable, (e.g. electricity consumption, divided by the proportionate change in a specified independent variable; electricity price). A dependent variable is highly elastic with respect to a given independent variable if the calculated elasticity is much greater than one. The dependent variable is inelastic if the elasticity is less than one.

End-use model A model used to analyze and forecast energy demand, which focuses on the end uses or services provided by energy. Typical end uses are lighting, process heat and motor drive. For a given industry, the model estimates the influence of prices and technological change on the evolution of the secondary energy inputs required to satisfy the industry's end uses over time.

Energy The amount of electricity delivered or consumed over a certain time period, measured in multiples of watt-hours. A 100-watt bulb consumes 200 watt-hours in two hours. A typical BC Hydro residential account consumes about 10,000 kWh (10 million watt-hours) annually.

Intensity A unitized measure of energy consumption, typically in kilowatt-hours per unit of stock. For example, kWh per account in the residential sector or kWh per unit of production in the industrial sector.

Gross Domestic Product (GDP) A measure of the total flow of goods and services produced by the economy over a specified time period, normally a year or quarter. It is obtained by valuing outputs of goods and services at market prices (alternatively at factor cost), and then aggregating the total of all goods and services.

Gigawatt-hour (GWh) A measure of electrical energy, equivalent to one million kilowatt-hours. (See Units of Measure.)

Integrated system That portion of the BC Hydro system which is connected as one whole. Non-integrated facilities refer to generating facilities that are not connected to the system, located in remote areas of the province.

kilowatt-hour (kWh) A measure of electrical energy, equivalent to the energy consumed by a 100-watt bulb in 10 hours. (See Units of Measure.)

Load The total amount of electrical power demanded by the utility's customers at any given time, typically measured in megawatts (MW).

Megawatt (MW) A unit used to measure the capacity or potential to generate or consume electricity. One MW equals one million watts. (See Units of Measure.)

Monte Carlo method A technique for estimating probabilities involving the construction of a model and the simulation of the outcome of an activity a large number of times. Random sampling techniques are used to generate a range of outcomes. Probabilities are estimated from an analysis of this range of outcomes.

MVA Megavolt-Amps – a unit of apparent power. Apparent power is real power in MW divided by power factor.

Natural conservation The increase in energy efficiency that would occur in the absence of any utility-induced demand-side management program, all other things being equal.

Normalization The correction of actual customer sales and peak demand for factors such as unusually warm or cold weather.

Price elasticity of demand The percentage change in quantity demanded, divided by the percentage change in price that caused the change in quantity demanded.

Real price increases Increases that have been adjusted for changes in prices of all goods. The nominal price of an item may rise by 10 per cent over a year, but inflation (and assumed wages) may have risen by seven per cent over the same time period. Therefore the effective price increase faced by the consumer is three per cent. It is necessary to deflate current prices by an appropriate inflation index (the CPI in Canada) to convert money values to constant prices or real terms.

Stock A quantity representing a number of energy consuming units. For example, in the residential sector, stock is the number of accounts or housing units; in the commercial sector, stock is represented by the floor area of commercial building space.

System peak demand The greatest combined demand of all BC Hydro customers faced by the generation system during a given fiscal year.

Transmission voltage customer A BC Hydro customer that is supplied its electricity via high-voltage transmission lines (60 kV or above).

Units of measure The large amounts of electricity generated and consumed on a system-wide basis are discussed in multiples of the basic units of watt and watt-hours. Kilowatts and megawatts are used to measure power, and kilowatt-hours, megawatt-hours, and gigawatt-hours are used to measure energy. The equivalences are:

1 kilowatt (kW)	=	1000 watts
1 megawatt (MW)	=	1000 kilowatts or 1 million watts
1 kilowatt-hour (kWh)	=	1000 watt-hours
1 megawatt-hour (MWh)	=	1000 kilowatt-hours or 1 million watt-hours
1 gigawatt-hour (GWh)	=	1000 megawatt-hours or 1 billion watt-hours

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Appendix 1. Price and Income Elasticities For Electricity Consumption

The own price elasticity of electricity consumption is a measure of the responsiveness of the quantity of electricity demanded to a small change in electricity price. Formally, the definition of the own price elasticity of consumption is shown in (A1.1).

(A1.1) $\varepsilon = (\Delta C/C)/(\Delta P/P)$

Here:

- Δ refers to a small change in the following variable;
- C refers to consumption in GWh; and
- P refers to an electricity price index.

The own price elasticity of consumption measures the percentage change in consumption caused by a one per cent change in electricity price.

The cross price elasticity of electricity consumption is a measure of the responsiveness of the quantity of electricity demanded to a small change in gas price. Formally, the definition of the cross price elasticity of consumption is shown in (A1.2).

(A1.2) $\varepsilon = (\Delta C/C)/(\Delta G/G)$

Here:

- Δ refers to a small change in the following variable;
- C refers to consumption in GWh; and
- G refers to a gas price index.

The cross price elasticity of consumption measures the percentage change in consumption caused by a one per cent change in gas price.

The income elasticity of electricity consumption is a measure of the responsiveness of the quantity of electricity demanded to a small change in income. Formally, the definition of the income elasticity of consumption is shown in (A1.3).

(A1.3) $\eta = (\Delta C/C)/(\Delta Y/Y)$

Here:

- Δ refers to a small change in the following variable;
- C refers to consumption in GWh; and
- Y refers to a provincial GDP in billions of constant 1997 dollars.

The income elasticity of consumption measures the percentage change in consumption caused by a one per cent change in income.

Maximum likelihood methods are used to estimate the price and income elasticities of electricity consumption for the total domestic load. The outcome variable is the log of the total domestic load in GWh (on a weather-adjusted basis). The independent variables are the log of real GDP in billions of 1997 dollars, the log of the price of electricity to a base of 1997 = 100, and the log of the real price of natural gas to a base of 1997 = 100.

The Cobb-Douglas specifications are used, and the model is estimated both with (A1.4) and without (A1.5) gas prices as an explanatory variable, where e is the error term.

(A1.4) $\text{lnC}_t = \text{lnconstant} + \alpha^*\text{lnY}_t + \beta^*\text{lnP}_t + e_t$

(A1.5) $\text{lnC}_t = \text{lnconstant} + \alpha^*\text{lnY}_t + \beta^*\text{lnP}_t + \gamma^*\text{lnG}_t + e_t$

In both cases, the error terms are modeled as first-order auto-regressive scheme (A1.6)

(A1.6) $e_t = \rho e_{t-1} + u_t$, t =1, 2, …, T

Assuming that the absolute value of the parameter ρ is less than one, the u_t are independently and identically distributed with variance σ_u^2, and e_t are generated by a stationary stochastic process beginning in the indefinite past. Roughly speaking, a stochastic process is stationary if the mean, variance and covariances for given lags are constant.

Table A1.1 shows that according to Model 1, the “without gas” price model, a one per cent increase in GDP increases domestic electricity sales by 0.42 per cent while a one per cent increase in the price of electricity reduces domestic electricity sales by 0.30 per cent. According to Model 2, the “with gas” price model, a one per cent increase in GDP increases domestic electricity sales by 0.28 per cent, a one per cent increase in the price of electricity sales reduces electricity sales by 0.60 per cent, and a one per cent increase in price of gas reduces electricity demand by 0.034 per cent. The negative sign for the effect of gas prices is counter-intuitive. Given this anomaly in the impact of natural gas price, the “without gas” price estimates are more appropriate for the analysis of energy consumption sensitivities.

Table A1.1. Maximum Likelihood Estimates of Energy Elasticities

Variable	Model 1 (Without Gas)	Model 2 (With Gas)
Constant	7.21 (3.63)	10.3 (4.33)
Log GDP	0.42 (0.20)	0.28 (0.23)
Log electricity price	-0.30 (0.28)	-0.60 (0.37)
Log gas price	-	-0.034 (0.028)
Log likelihood	30.8	31.8
Durbin-Watson	2.24	2.14

Appendix 2. Price and Income Elasticities For Peak Demand

The own price elasticity of electricity peak demand is a measure of the responsiveness of peak demand to a small change in price. Formally, the definition of the own price elasticity of peak demand is shown in (A2.1).

(A2.1) $\varepsilon = (\Delta D/D)/(\Delta P/P)$

As before:

- Δ refers to a small change in the following variable;
- D refers to peak demand in MW; and
- P refers to an electricity price index.

The own price elasticity of peak demand measures the percentage change in peak demand caused by a one per cent change in electricity price.

The cross price elasticity of electricity consumption is a measure of the responsiveness of peak demand to a small change in gas price. Formally, the definition of the cross price elasticity of consumption is shown in (A2.2).

(A2.2) $\varepsilon = (\Delta D/D)/(\Delta G/G)$

Here:

- Δ refers to a small change in the following variable;
- D refers to demand MW; and
- G refers to a gas price index.

The cross price elasticity of consumption measures the percentage change in consumption caused by a one per cent change in gas price.

The income elasticity of electricity peak demand is a measure of the responsiveness of peak demand to a small change in income. Formally, the definition of the income elasticity of peak demand is shown in (A2.3).

(A2.3) $\eta = (\Delta D/D)/(\Delta Y/Y)$

Here:

- Δ refers to a small change in the following variable,
- D refers to peak demand in MW; and
- Y refers to a provincial GDP in billions of constant 1997 dollars.

The income elasticity of peak demand measures the percentage change in peak demand consumption caused by a one per cent change in income.

Maximum likelihood methods are used to estimate the price and income elasticities of peak demand for the total domestic load. The outcome variable is the log of the total peak load in MW (on a weather-adjusted basis), and the independent variables are the log of real GDP in billions of 1997 dollars, the log of the price of electricity to a base of 1997 = 100, and the log of the real price of natural gas to a base of 1997 = 100.

The Cobb-Douglas specifications are used and the model is estimated both with (A2.4) and without (A2.5) gas prices as an explanatory variable, where e is the error term.

(A2.4) $\ln C_t = \ln constant + \alpha{*}\ln Y_t + \beta{*}\ln P_t + e_t$

(A2.5) $\ln C_t = \ln constant + \alpha{*}\ln Y_t + \beta{*}\ln P_t + \gamma{*}\ln G_t + e_t$

In both cases the error terms are modelled as first-order auto-regressive scheme (A2.6)

(A2.6) $e_t = \rho e_{t-1} + u_t$, $t = 1, 2, \ldots, T$

Assuming that the absolute value of the parameter ρ is less than one, the u_t are independently and identically distributed with variance σ_u^2, and e_t are generated by a stationary stochastic process beginning in the indefinite past. Roughly speaking, a stochastic process is stationary if the mean, variance and covariances for given lags are constant.

Table A2.1 shows that according to Model 1, the “without gas” price model, a one per cent increase in GDP increases domestic peak demand by 0.25 per cent while a one per cent increase in the price of electricity reduces domestic peak demand by 0.32 per cent. According to Model 2, the “with gas” price model, a one per cent increase in GDP increases domestic electricity sales by 0.24 per cent, a one per cent increase in the price of electricity sales reduces electricity sales by 0.36 per cent, and a one per cent increase in price of gas reduces electricity demand by 0.0085 per cent. Again, the negative sign for the effect of gas prices is counter-intuitive. Given this anomaly in the impact of natural gas price, the “without gas” price estimates are more appropriate for the analysis of peak demand sensitivities.

Table A2.1. Maximum Likelihood Estimates of Peak Elasticities

Variable	Model 1 (Without Gas)	Model 2 (With Gas)
Constant	7.63 (4.41)	8.00 (4.93)
Log GDP	0.25 (0.25)	0.24 (0.27)
Log electricity price	-0.32 (0.35)	-0.36 (0.41)
Log gas price	-	-0.0085 (0.031)
Log likelihood	29.9	30.0
Durbin-Watson	1.62	1.65

Appendix 3. Weather Normalization for Energy

Weather-normalized sales are an estimate of the sales that would have been made if normal weather had been experienced. Sales are adjusted using heating degree-days (a standard approach used by the utility industry). A degree-day is measure of coldness, defined by the number of degrees below 18 degrees Celsius in (A3.1), for the average daily temperature. For example, if the average temperature on day t is 12 degrees Celsius then that day has 18-12 = 6 heating degree-days. The heating degree-days for a month are the sum of the heating degree-days for the days in that month.

Formally, for day t heating degree-days is defined in (A3.1) where max is the maximum function.

(A3.1) $\text{heating degree-day}_t = \max\,(18°\text{C} – \text{average daily temperature, zero})$

Note that degree-days are never negative because the heating system will not be required to produce heat at temperatures above 18°C.

We assume that the monthly residential use rate for a given class of residential accounts can be modelled using the following cubic polynomial (A3.2.).

(A3.2) $\text{use rate}_t = \alpha + \beta^*\text{HDD}_t + \chi^*\text{HDD}_t^2 + \delta^*\text{HDD}_t^3 + \varepsilon_t$

The most recent 36 months of data available is used to estimate each regression, which is modelled using ordinary least squares. To calculate the weather-adjusted use rate for a particular period, the heating degree-days for the period are substituted into the estimated regression equation (A3.2).

It is important to note the following points:

- First, weather normalization is undertaken for the residential sector only since only limited evidence exists of weather response for the commercial and industrial sectors. This means that when weather-normalized totals are reported, only the residential part of the total is actually weather-adjusted. Although this is not viewed as a major source of error, research is being conducted to determine if and how the commercial and industrial loads should be weather normalized.
- Second, the model actually normalizes the use per account or the use rate rather than sales per se. Normalized sales are then calculated as normalized use rate multiplied by the average number of accounts for the class. Eight classes are used in these calculations, namely a heating and non-heating class in each of the four regions.
- Third, because this forecast uses billed sales rather than the unknown actual consumption by class, monthly heating degree-days are allocated using a 25/50/25 per cent adjustment to match the assumed pattern of meter reading.

Table A3.1 compares the actual and weather-normalized sales for BC Hydro's service territory for the fiscal years 1993/94 to 2002/03.

Table A3.1. Actual and Weather-Normalized Sales for BC Hydro Service Territory

Year	Actual (GWh)	Weather Normalized (GWh)
1993/94	40979	41367
1994/95	41616	41992
1995/96	42851	43055
1996/97	43598	43095
1997/98	42607	43115
1998/99	44863	45418
1999/00	45638	45542
2000/01	46806	46628
2001/02	46412	46252
2002/03	47612	47789

Appendix 4. Weather Normalization for Peak

The domestic generation load is made up of the transmission load plus the distribution load plus losses. The transmission load is assumed to be insensitive to weather. The distribution load is sensitive to weather primarily through the residential heating load. Using appropriate data, the transmission load is netted out and the distribution load then weather normalized separately.

A daily peak model was estimated for each year to be weather normalized. Daily peaks are modelled as a function of trend, day type, and weather variables. The daily peak model is specified as (A4.1).

(A4.1) $peak_t = \alpha + \beta * trend_t + \chi * weekend_t + \delta * xmas_t + \phi * daylight_t + \gamma * temp_t + \eta * temp_t * daylight_t + \varphi * temp_t^2 + \lambda * temp_t^3 + \varepsilon_t$

The variables are as follows.

- Peak is the daily peak in MW;
- Trend is a linear trend indexed by day t of the year;
- Weekend takes the value one for weekends and holidays and zero for weekdays;
- Xmas takes the value one for days between Christmas and New Year and zero otherwise;
- Daylight is the number of daylight hours;
- Temp is the daily average temperature; and
- ε is the random error.

Once the model is estimated, the estimated daily peak model for each given year is loaded with the preceding 30 historical weather years (a set of 365 daily temperatures), one year at a time. The simulated annual peaks are found for each of the 30 annual simulations. A histogram can be generated, showing the probability distribution of the annual simulated peaks. The weather-normalized peak for each given year is computed as the average of the thirty simulated annual peaks.

Table A4.1 compares the actual and weather-normalized sales for BC Hydro's service territory for the fiscal years 1993/94 to 2002/03. Note that elsewhere the peak is for the integrated system and is somewhat higher.

Table A4.1. Actual and Weather-Normalized Peak for BC Hydro Integrated System

Year	Actual (MW)	Bottom-up Approach Substation Weather-Normalized[1] (MW)	Top-Down Procedure Weather-Normalized (MW)	Weather-Adjusted Base Year for Forecast
1993/94	8059	8209		8209
1994/95	8168	8253		8253
1995/96	8451	8301		8301
1996/97	8267	8271		8271
1997/98	8243	8385		8385
1998/99	8777	8772	9076	8772
1999/00	8423	8835	9053	8835
2000/01	8995	8986	9154	8986
2001/02	8692	9016	9339	9016
2002/03	8481	8972	9127	9082

Note 1. As released in VIGP hearing.

Appendix 5. Ordinary Least Squares-Based Forecasts

Most economic analysis deals with situations where the outcome variables can be assumed to be continuous and normally distributed. These include decisions about how much of a product to purchase, how much of a product to produce and what price to charge for a product. In each of these cases, explaining the determinants of the variable typically involves modelling the outcome variable as a continuous function of a set of k explanatory or independent variables, a set of k associated parameters, plus an error term ε assumed to be normally distributed with mean zero, constant variance σ^2 and covariances equal to zero (there is no correlation between errors for different observations). The basic idea of least squares regression is to choose the parameters to minimize the sum of squares of the errors. The assumption of normally distributed errors is not necessary to apply ordinary least squares regression, but some assumption on the distribution of errors is needed to generate test statistics for the parameters.

The rationale for using minimum least squared error as the criterion for choosing parameter values makes intuitive sense since large errors are more important than are small errors. Equally important is the fact that ordinary least squares estimators have desirable properties in the classical regression context. In particular, ordinary least squares estimates are unbiased and have minimum variance in the class of linear unbiased estimators. In other words, they are the best estimator for this class of regression problem.

In the typical set-up, then, the regression model is given by:

(A5.1) $y_t = x'_t\beta + \varepsilon_t$, where $\varepsilon_t \sim N(0, \sigma^2)$ and t = 1,2, … T

Here:

- y_t is the dependent variable at observation;
- t is a k×1 vector of independent variables at observation t;
- β is a k×1 vector of parameters assumed constant for all observations; and
- T is the number of observations.

In other words, (A5.1) is a set of T equations where the value of y_t at time t is a linear function of k variables, $x_{1t}, x_{2t}, \ldots , x_{kt}$.

It is convenient for what follows to write equation (A5.1) in matrix form as follows

(A5.2) $y = X'\beta + \varepsilon$,

where:

- y is a T×1 vector;
- X is a k×T matrix;
- β is a T×1 vector; and
- ε is a T×1 vector.

Assuming that X is a non-stochastic matrix of full rank $k \leq T$ that satisfies the regularity condition $\lim_{T\to\infty} (X'X/T) = Q$, where Q is a finite and non-singular matrix, and using E for the expectation operator, note that the $E(\varepsilon)$ is zero since the expectation of each of its components is zero.

Defining the sum of the squared errors as S, note that the variance of the errors is the expectation of S:

(A5.3) $S \equiv \varepsilon'\varepsilon = (y - X'\beta)' (y - X'\beta)$ and $E\varepsilon\varepsilon' = \sigma^2 I$

The ordinary least squares estimators of the vector of parameters β^* and the variance of the errors σ^{2*} are found by minimizing the sum of the squared errors

(A5.4) $\partial S/\partial\beta = -2X'y + 2X'X\beta^* = 0$

Solving (A6.5) for β^* the estimated value of β yields the following expression

(A5.5) $\beta^* = (X' X)^{-1} X' y$

The ordinary least squares estimate of the variance of the errors σ^2 is given by the following expression:

(A5.6) $\sigma^{2*} = \varepsilon^{*\prime}\varepsilon^* / (T - k)$ where $\varepsilon^* = y - X\beta^*$

The estimate of σ^2 is used to estimate confidence intervals and to conduct hypotheses tests for the parameters. Further, the least squares estimates of the parameters can be shown to be unbiased and consistent estimates of the population parameters.

It may be useful to find the effect of a change in an independent variable on the outcome variable. This partial effect is found by calculating the relevant partial derivative and in the linear model is just the value of the regression coefficient for that variable.

(A5.7) $\partial y/\partial x = \partial(X\beta + \varepsilon)\partial x = \beta$, since the derivative of ε is zero.

Finally, the measure of goodness of fit for an ordinary least squares regression is R-squared adjusted for degrees of freedom, which is calculated as the explained sum of square divided by the total sum of squares times T – k divided by T.

Table A5.1 presents ordinary least squares regression models for energy and peak based on the weather-normalized data for 1993/94 to 2002/03. The dummy variable takes on the value one for 1997/98 and zero otherwise and is designed to capture the strike impacts in that year.

Table A5.1. Ordinary Least Squares Models

	Energy (GWh)	**Peak (MW)**
Constant	16720 (1970)	4279 (482)
GDP	0.24 (0.017)	0.038 (0.0042)
Dummy	-1320 (465)	-221 (113)
Adjusted R-squared	0.96	0.90
Durbin-Watson	2.30	1.36

Table A5.2 presents forecasts of energy and peak based on the previous regressions. Note that the reference energy is for the total BC Hydro service area before Power Smart and that the reference peak is for the domestic system. OLS energy and reference energy are five per cent or less apart for the forecast years. OLS peak and reference peak are also five per cent or less apart for the forecast years.

Table A5.2. Comparison of OLS and Reference Energy and Peak Before Power Smart

Year	**OLS Energy (GWh)**	**Reference Energy (GWh)**	**OLS Peak (MW)**	**Domestic Integrated Peak (MW)**
2003/04	47743	48004	9123	9339
2004/05	48550	48754	9249	9500
2005/06	49505	49452	9398	9662
2006/07	50456	50179	9546	9818
2007/08	51434	51046	9699	10004
2008/09	52371	51803	9845	10176
2009/10	53298	52593	9990	10355
2010/11	54249	53414	10139	10515
2011/12	55150	54206	10279	10678
2012/13	56034	54983	10417	10836
2013/14	56977	55741	10565	10992
2014/15	57944	56542	10715	11167
2015/16	58933	57353	10870	11343
2016/17	59946	58136	11028	11518
2017/18	60984	58942	11190	11693
2018/19	62002	59756	11349	11868
2019/20	63043	60588	11512	12044
2020/21	64108	61458	11678	12219
2021/22	65198	62298	11848	12394
2022/23	66313	63173	12022	12569
2023/24	67454	64066	12200	12745

Appendix 6. Maximum Likelihood-Based Forecasts

The main alternative to least squares estimation is maximum likelihood estimation. It is normally used in circumstances where the underlying assumptions of the standard linear model are not met, but it is convenient to first review maximum likelihood estimation of the standard linear model (described in Appendix 5) before considering the more complicated case of auto-correlated residuals. The basic idea of maximum likelihood estimation is to choose estimates for the parameter values that maximize the probability that the distribution represented by the estimated parameters generated the observed sample.

Formally, consider the normal linear regression model considered in Appendix 5, the joint likelihood for the T observations is the product of T normal densities as follows:

(A6.1) $L = f(y_1, y_2, \ldots, y_T) = (2\pi\sigma^2)^{-T/2} \exp\{-(2\sigma^2)^{-1}(y - X\beta)'(y - X\beta)\}$

Taking the log of this expression yields:

(A6.2) $\ln L = -T/2 \ln(2\pi) - T/2 \ln(\sigma^2) - (2\sigma^2)^{-1}(y - X\beta)' (y - X\beta)$

Maximizing the log likelihood function with respect to the parameters yields the first order conditions given by expressions (A6.3) and (A6.4):

(A6.3) $\partial L/\partial\beta = -\sigma^{-2} (-X'y + X'X\beta) = 0$

(A6.4) $\partial L/\partial\sigma^2 = -T (2\sigma^2)^{-1} + (2\sigma^4)^{-1} (y - X\beta)'(y - X\beta) = 0$

Solving these equations for the unknown parameters yields the estimators (A6.5) and (A 6.6):

(A6.5) $\beta^{**} = (X'X)^{-1}X'y$

(A6.6) $\sigma^{2**} = \varepsilon^{**\prime}\varepsilon^{**}/T = (T - k)/T\ \sigma^{2*}$

The maximum likelihood estimate of β is the same as the ordinary least squares estimate for this model and is unbiased and consistent. The maximum likelihood estimate of σ^2 is different from the ordinary least squares estimate by the factor $T/(t - k)$, and is therefore a biased estimator, but it is a consistent estimate since as $T\rightarrow\infty$ the bias goes to zero. In fact, the strength of maximum likelihood estimators is that under fairly general conditions they are consistent, asymptotically normal and asymptotically efficient. These features account for their widespread use in econometrics in situations where least squares estimates are inappropriate because the requirements of the classical linear regression model are not met.

Up to now we have assumed that covariances of the errors are zero or that there is no auto-correlation. However in many cases, errors are correlated over time, often due to persistent shocks reflecting the inertia of economic processes or due to omitted variables that are hopefully uncorrelated to variables in the model.

Consider the linear model:

(A6.7) $y = X'\beta + \varepsilon$,

where:

- y is a $T\times1$ vector;
- X is a $k\times T$ matrix;
- β is a $T\times1$ vector; and
- ε is a $T\times1$ vector;

but where:

(A6.8) $\varepsilon_t = \rho\varepsilon_{t-1} + u_t$, $t = 1,2, \ldots,T$

Assuming that the absolute value of the parameter ρ is less than one, the u_t are independently and identically distributed with variance σ_u^2, and ε_t are generated by a stationary stochastic process beginning in the infinite past. Roughly speaking, a stochastic process is stationary if the mean, variance and covariances for given lags are constant over time.

The form of the errors is awkward to work with and the calculations can be simplified by expanding the previous expression by making successive substitutions for ε_t to yield:

(A6.9) $\varepsilon_t = \Sigma\rho^i u_{t-1}$, where the sum runs over $i = 0,1,\ldots,\infty$

Using the assumptions on u_t and the formula for the sum of a converging series gives the variance of ε_t as follows:

(A6.10) $E(\varepsilon_t^2) = \rho^0E(u_t^2) + \rho^2(u_t^2) + \rho^4E(u_u^4) + \ldots = \sigma_u^2/(1 - \rho^2) = \sigma_\varepsilon^2$

Finally, the covariance of ε_t with ε_{t-i} is needed, which is:

(A6.11) $E(\varepsilon_t\varepsilon_{t-i}) = E([u_t + \rho u_{t-1} + \rho^2u_{t-2} + \ldots]*[u_t + \rho u_{t-1} + \rho^2u_{t-2} +\ldots]) = \rho^i\sigma_\varepsilon^2$

This gives all the variances and covariances in the variance-covariance matrix for ε_t. Noting that every term contains σ_u^2, this common term can be extracted and the variance-covariance matrix can be written as follows:

(A6.12) $E\varepsilon\varepsilon' = \sigma_u^2\Omega$

If the value of ρ were known, the value of β could be found that minimizes this sum of squares as with for the ordinary least squares estimator to yield the generalized least squares estimator:

(A6.13) $\beta^* = (X'\Omega^{-1}X)^{-1}X'\Omega^{-1}y$

But since the value of ρ is not known, a maximum likelihood estimator can be used, which gives us consistent and asymptotically efficient estimates of the parameters. Starting by formulating the likelihood function in the usual way and taking its log that yields:

(A6.14) $\ln L(y, X, \beta, \sigma_u^2, \rho) = -T/2 \ln(2\pi) - 1/2 \ln|\sigma_u^2\Omega| - (2\sigma_u^2)^{-1}(y - X\beta)'$
$\Omega^{-1}(y - X\beta)$

This expression can be simplified by partially maximizing with respect to $\beta(\rho)$ and $\sigma_u^2(\rho)$ which, noting that these expressions are functions of ρ, yields the simpler concentrated likelihood function:

(A6.15) $\ln L^*(\rho, y, X) = -T/2\{\ln(2\pi) + 1\} -T/2 \ln\{[\sigma_u^2(\rho)][(1 - \rho^2)^{-1/T}]\}$

Maximizing this function with respect to ρ is then a relatively straightforward numerical estimation problem. The method of Beach-MacKinnon (1978) can be used to maximize this function.

Table A6.1 presents maximum likelihood regression models for energy and peak based on weather-normalized data for 1993/94 to 2002/03.

Table A6.1. Maximum Likelihood Models

	Energy (GWh)	**Peak (MW)**
Constant	16680 (1493)	4548 (603)
GDP	0.24 (0.013)	0.035 (0.0052)
Dummy	-1225 (431)	-191 (99)
Log likelihood	-72.8	-58.8
Durbin-Watson	2.15	1.46

Table A6.2 presents forecasts of energy and peak based on the previous regressions. Note that the reference energy is for total BC Hydro service area before Power Smart and that the reference peak is for the domestic system. ML energy and reference energy are five per cent or less apart for the years of the forecast. ML peak and reference peak are also five per cent or less apart for the forecast years.

Table A6.2. Comparison of Maximum Likelihood and Reference Forecasts Energy and Peak Before Power Smart

Year	Maximum Likelihood Energy (GWh)	Reference Energy (GWh)	Maximum Likelihood Peak (MW)	Domestic Integrated System Peak (MW)
2003/04	47712	48004	9093	9339
2004/05	48518	48754	9211	9500
2005/06	49474	49452	9351	9662
2006/07	50425	50179	9490	9818
2007/08	51403	51046	9634	10004
2008/09	52341	51803	9771	10176
2009/10	53268	52593	9907	10355
2010/11	54219	53414	10046	10515
2011/12	55120	54206	10178	10678
2012/13	56004	54983	10308	10836
2013/14	56948	55741	10446	10992
2014/15	57914	56542	10587	11167
2015/16	58904	57353	10732	11343
2016/17	59917	58136	10881	11518
2017/18	60955	58942	11033	11693
2018/19	61973	59756	11182	11868
2019/20	63015	60588	11334	12044
2020/21	64081	61458	11491	12219
2021/22	65171	62298	11650	12394
2022/23	66286	63173	11814	12569
2023/24	67427	64066	11981	12745

Appendix 7. Reference Load Forecast

Tables A7.1 and A7.2 summarize BC Hydro's reference load forecast including the effects of Power Smart and before Power Smart. Table A7.3 to A7.6 summarize BC Hydro's high and low scenarios resulting from the Monte Carlo uncertainty analysis (See Section 7.3) including the effects of Power Smart and before Power Smart.

Table A7.1. 2003 BC Hydro, Reference Load Forecast Before Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1998/99	13,972	12,814	18,077	44,863	650	45,513	292	45,805	5,092	50,897	9,077	50,648	9,026
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,369	52,718	9,319
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,340	53,339	8,868	53,050	8,816
Forecast													
2003/04	15,688	13,908	18,409	48,004	1,109	49,113	322	49,435	5,409	54,844	9,715	54,563	9,662
2004/05	15,955	14,120	18,679	48,754	1,090	49,844	320	50,164	5,493	55,657	9,876	55,375	9,823
2005/06	16,244	14,403	18,806	49,452	1,110	50,563	320	50,883	5,580	56,463	10,042	56,180	9,989
2006/07	16,544	14,723	18,913	50,179	1,105	51,284	320	51,604	5,669	57,273	10,202	56,990	10,148
2007/08	16,857	15,050	19,139	51,046	1,124	52,170	322	52,492	5,773	58,265	10,393	57,977	10,338
2008/09	17,134	15,346	19,323	51,803	1,185	52,988	320	53,308	5,868	59,176	10,570	58,884	10,514
2009/10	17,431	15,658	19,505	52,593	1,203	53,796	320	54,116	5,964	60,080	10,750	59,783	10,693
2010/11	17,737	15,985	19,692	53,414	1,221	54,635	320	54,955	6,063	61,018	10,911	60,716	10,853
2011/12	18,058	16,281	19,868	54,206	1,239	55,446	322	55,767	6,159	61,926	11,075	61,620	11,016
2012/13	18,363	16,578	20,042	54,983	1,258	56,241	320	56,561	6,254	62,815	11,234	62,504	11,175
2013/14	18,671	16,844	20,227	55,741	1,278	57,020	321	57,341	6,345	63,686	11,390	63,371	11,330
2014/15	18,982	17,143	20,417	56,542	1,300	57,841	321	58,162	6,442	64,604	11,567	64,284	11,506
2015/16	19,293	17,449	20,611	57,353	1,319	58,673	323	58,995	6,540	65,535	11,743	65,210	11,681
2016/17	19,604	17,722	20,810	58,136	1,336	59,471	321	59,793	6,634	66,427	11,920	66,095	11,856
2017/18	19,914	18,015	21,013	58,942	1,352	60,295	321	60,616	6,731	67,347	12,096	67,010	12,031
2018/19	20,223	18,320	21,213	59,756	1,369	61,125	321	61,446	6,829	68,275	12,272	67,932	12,207
2019/20	20,529	18,642	21,417	60,588	1,386	61,974	323	62,297	6,929	69,226	12,449	68,878	12,382
2020/21	20,835	18,995	21,627	61,458	1,403	62,861	321	63,182	7,033	70,215	12,625	69,861	12,557
2021/22	21,139	19,319	21,840	62,298	1,421	63,719	321	64,040	7,133	71,173	12,802	70,813	12,732
2022/23	21,441	19,673	22,059	63,173	1,439	64,611	321	64,933	7,238	72,171	12,978	71,805	12,908
2023/24	21,743	20,040	22,283	64,066	1,457	65,523	323	65,846	7,345	73,191	13,155	72,820	13,083
Growth Rates:													
5 yrs 02/03-07/08	2.0%	1.9%	0.6%	1.4%	0.9%	1.4%	0.5%	1.4%	5.9%	1.8%	3.2%	1.8%	3.2%
11 yrs 02/03-13/14	1.8%	1.9%	0.8%	1.4%	1.6%	1.4%	0.2%	1.4%	3.5%	1.6%	2.3%	1.6%	2.3%
21 yrs 02/03-23/24	1.7%	1.8%	0.9%	1.4%	1.5%	1.4%	0.1%	1.4%	2.5%	1.5%	1.9%	1.5%	1.9%

Note: Losses are assumed to be 4% Distribution and 8.1% Transmission

Table A7.2. 2003 BC Hydro, Reference Load Forecast With Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1998/99	13,972	12,814	18,077	44,863	650	45,513	292	45,805	5,092	50,897	9,077	50,648	9,026
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,369	52,718	9,319
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,340	53,339	8,868	53,050	8,816
Forecast													
2003/04	15,638	13,843	18,268	47,749	1,109	48,858	322	49,180	5,383	54,563	9,673	54,282	9,620
2004/05	15,816	13,870	18,227	47,913	1,090	49,003	320	49,323	5,405	54,728	9,740	54,446	9,687
2005/06	16,042	14,011	18,154	48,207	1,110	49,317	320	49,637	5,449	55,086	9,840	54,803	9,787
2006/07	16,280	14,208	18,044	48,532	1,105	49,637	320	49,957	5,497	55,454	9,934	55,171	9,881
2007/08	16,526	14,467	18,069	49,062	1,124	50,186	322	50,508	5,567	56,075	10,072	55,787	10,017
2008/09	16,730	14,718	18,057	49,505	1,185	50,690	320	51,010	5,631	56,641	10,199	56,349	10,144
2009/10	16,950	14,993	18,044	49,987	1,203	51,190	320	51,510	5,697	57,207	10,330	56,910	10,274
2010/11	17,171	15,280	18,052	50,503	1,221	51,724	320	52,044	5,766	57,810	10,442	57,508	10,385
2011/12	17,410	15,537	18,068	51,015	1,239	52,254	322	52,576	5,834	58,410	10,560	58,104	10,502
2012/13	17,716	15,834	18,242	51,792	1,258	53,050	320	53,370	5,928	59,298	10,719	58,987	10,660
2013/14	18,023	16,101	18,426	52,550	1,278	53,828	321	54,149	6,020	60,169	10,876	59,854	10,816
2014/15	18,334	16,400	18,616	53,350	1,300	54,650	321	54,971	6,117	61,088	11,052	60,768	10,991
2015/16	18,646	16,706	18,809	54,161	1,319	55,480	323	55,803	6,215	62,018	11,229	61,692	11,166
2016/17	18,957	16,979	19,008	54,944	1,336	56,280	321	56,601	6,309	62,910	11,405	62,579	11,342
2017/18	19,267	17,273	19,213	55,753	1,352	57,105	321	57,426	6,406	63,832	11,582	63,495	11,517
2018/19	19,576	17,577	19,412	56,565	1,369	57,934	321	58,255	6,503	64,758	11,758	64,415	11,692
2019/20	19,882	17,900	19,615	57,397	1,386	58,783	323	59,106	6,603	65,709	11,934	65,361	11,867
2020/21	20,188	18,253	19,826	58,267	1,403	59,670	321	59,991	6,708	66,699	12,111	66,345	12,043
2021/22	20,492	18,576	20,039	59,107	1,421	60,528	321	60,849	6,808	67,657	12,287	67,297	12,218
2022/23	20,794	18,930	20,259	59,983	1,439	61,422	321	61,743	6,913	68,656	12,464	68,291	12,393
2023/24	21,096	19,297	20,482	60,875	1,457	62,332	323	62,655	7,020	69,675	12,640	69,304	12,568
Growth Rates:													
5 yrs 02/03-07/08	1.6%	1.1%	-0.6%	0.6%	0.9%	0.6%	0.5%	0.6%	5.1%	1.0%	2.6%	1.0%	2.6%
11 yrs 02/03-13/14	1.5%	1.5%	-0.1%	0.9%	1.6%	0.9%	0.2%	0.9%	3.0%	1.1%	1.9%	1.1%	1.9%
21 yrs 02/03-23/24	1.5%	1.6%	0.5%	1.2%	1.5%	1.2%	0.1%	1.2%	2.3%	1.3%	1.7%	1.3%	1.7%

Note: Losses are assumed to be 4% Distribution and 8.1% Transmission

Table A7.3. 2003 BC Hydro, High Scenario Load Forecast Before Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1998/99	13,972	12,814	18,077	44,863	650	45,513	292	45,805	5,092	50,897	9,077	50,648	9,026
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,369	52,718	9,319
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,340	53,339	8,868	53,050	8,816
Forecast													
2003/04	15,823	13,947	18,505	48,275	1,109	49,384	322	49,705	5,440	55,145	9,768	54,856	9,714
2004/05	16,152	14,214	18,874	49,240	1,090	50,330	320	50,650	5,546	56,196	9,972	55,904	9,917
2005/06	16,508	14,557	19,057	50,122	1,110	51,232	320	51,552	5,654	57,206	10,175	56,912	10,119
2006/07	16,878	14,968	19,224	51,070	1,105	52,175	320	52,495	5,769	58,264	10,378	57,967	10,322
2007/08	17,252	15,377	19,510	52,139	1,124	53,263	322	53,585	5,896	59,481	10,610	59,178	10,553
2008/09	17,598	15,786	19,755	53,139	1,185	54,324	320	54,645	6,019	60,664	10,836	60,357	10,778
2009/10	17,953	16,180	19,982	54,115	1,203	55,318	320	55,638	6,136	61,774	11,053	61,462	10,994
2010/11	18,349	16,577	20,245	55,171	1,221	56,392	320	56,712	6,262	62,974	11,261	62,657	11,201
2011/12	18,757	16,960	20,492	56,209	1,239	57,448	322	57,770	6,387	64,157	11,473	63,835	11,412
2012/13	19,129	17,371	20,746	57,246	1,258	58,504	320	58,824	6,510	65,334	11,684	65,007	11,622
2013/14	19,504	17,757	20,986	58,247	1,278	59,525	321	59,847	6,631	66,478	11,890	66,147	11,827
2014/15	19,903	18,117	21,227	59,247	1,300	60,547	321	60,868	6,751	67,619	12,107	67,282	12,043
2015/16	20,283	18,481	21,520	60,284	1,319	61,603	323	61,926	6,874	68,800	12,328	68,458	12,263
2016/17	20,636	18,824	21,813	61,273	1,336	62,609	321	62,930	6,990	69,920	12,546	69,572	12,480
2017/18	21,037	19,217	22,073	62,327	1,352	63,679	321	64,000	7,116	71,116	12,773	70,762	12,705
2018/19	21,387	19,581	22,367	63,335	1,369	64,704	321	65,025	7,234	72,259	12,989	71,899	12,920
2019/20	21,769	19,983	22,671	64,423	1,386	65,809	323	66,132	7,363	73,495	13,216	73,129	13,146
2020/21	22,109	20,408	22,964	65,481	1,403	66,884	321	67,205	7,488	74,693	13,431	74,322	13,360
2021/22	22,460	20,882	23,284	66,626	1,421	68,047	321	68,368	7,623	75,991	13,668	75,613	13,595
2022/23	22,802	21,301	23,591	67,694	1,439	69,133	321	69,454	7,749	77,203	13,883	76,819	13,809
2023/24	23,216	21,772	23,915	68,903	1,457	70,360	323	70,683	7,892	78,575	14,122	78,185	14,047
Growth Rates:													
5 yrs 02/03-07/08	2.4%	2.3%	1.0%	1.8%	0.9%	1.8%	0.5%	1.8%	6.3%	2.2%	3.7%	2.2%	3.7%
11 yrs 02/03-13/14	2.2%	2.4%	1.1%	1.8%	1.6%	1.8%	0.2%	1.8%	3.9%	2.0%	2.7%	2.0%	2.7%
21 yrs 02/03-23/24	2.0%	2.2%	1.2%	1.8%	1.5%	1.8%	0.1%	1.8%	2.9%	1.9%	2.2%	1.9%	2.2%

Note: Losses are assumed to be 4% Distribution and 8.1% Transmission

Table A7.4. 2003 BC Hydro, Low Scenario Load Forecast Before Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1998/99	13,972	12,814	18,077	44,863	650	45,513	292	45,805	5,092	50,897	9,077	50,648	9,026
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,369	52,718	9,319
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,340	53,339	8,868	53,050	8,816
Forecast													
2003/04	15,552	13,874	18,312	47,738	1,109	48,847	322	49,168	5,380	54,548	9,662	54,278	9,611
2004/05	15,757	14,034	18,487	48,278	1,090	49,368	320	49,688	5,440	55,128	9,782	54,859	9,731
2005/06	15,994	14,240	18,541	48,775	1,110	49,885	320	50,205	5,505	55,710	9,908	55,442	9,857
2006/07	16,225	14,468	18,569	49,262	1,105	50,367	320	50,687	5,567	56,254	10,020	55,987	9,969
2007/08	16,478	14,711	18,711	49,900	1,124	51,024	322	51,346	5,646	56,992	10,166	56,720	10,114
2008/09	16,695	14,925	18,857	50,477	1,185	51,662	320	51,983	5,719	57,702	10,307	57,426	10,255
2009/10	16,958	15,163	18,959	51,080	1,203	52,283	320	52,603	5,795	58,398	10,449	58,118	10,396
2010/11	17,192	15,415	19,090	51,697	1,221	52,918	320	53,238	5,871	59,109	10,569	58,825	10,515
2011/12	17,420	15,618	19,155	52,193	1,239	53,432	322	53,754	5,934	59,688	10,674	59,399	10,619
2012/13	17,650	15,878	19,268	52,796	1,258	54,054	320	54,374	6,008	60,382	10,799	60,089	10,743
2013/14	17,890	16,072	19,364	53,326	1,278	54,604	321	54,926	6,075	61,001	10,910	60,704	10,853
2014/15	18,145	16,297	19,491	53,933	1,300	55,233	321	55,554	6,150	61,704	11,047	61,402	10,989
2015/16	18,386	16,464	19,599	54,449	1,319	55,768	323	56,091	6,214	62,305	11,164	61,998	11,105
2016/17	18,635	16,704	19,696	55,035	1,336	56,371	321	56,692	6,286	62,978	11,301	62,666	11,241
2017/18	18,884	16,938	19,809	55,631	1,352	56,983	321	57,304	6,360	63,664	11,435	63,347	11,374
2018/19	19,104	17,169	19,965	56,238	1,369	57,607	321	57,928	6,433	64,361	11,569	64,038	11,507
2019/20	19,343	17,399	20,101	56,843	1,386	58,229	323	58,552	6,507	65,059	11,699	64,730	11,636
2020/21	19,584	17,623	20,215	57,422	1,403	58,825	321	59,146	6,579	65,725	11,818	65,392	11,754
2021/22	19,807	17,865	20,305	57,977	1,421	59,398	321	59,719	6,648	66,367	11,937	66,028	11,872
2022/23	20,044	18,119	20,464	58,627	1,439	60,066	321	60,387	6,726	67,113	12,069	66,768	12,002
2023/24	20,286	18,369	20,568	59,223	1,457	60,680	323	61,003	6,800	67,803	12,186	67,453	12,118
Growth Rates:													
5 yrs 02/03-07/08	1.5%	1.4%	0.1%	0.9%	0.9%	0.9%	0.5%	0.9%	5.4%	1.3%	2.8%	1.3%	2.8%
11 yrs 02/03-13/14	1.4%	1.4%	0.4%	1.0%	1.6%	1.0%	0.2%	1.0%	3.1%	1.2%	1.9%	1.2%	1.9%
21 yrs 02/03-23/24	1.4%	1.4%	0.5%	1.0%	1.5%	1.1%	0.1%	1.0%	2.2%	1.1%	1.5%	1.2%	1.5%

Note: Losses are assumed to be 4% Distribution and 8.1% Transmission

Table A7.5. 2003 BC Hydro, High Scenario Load Forecast With Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1998/99	13,972	12,814	18,077	44,863	650	45,513	292	45,805	5,092	50,897	9,077	50,648	9,026
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,369	52,718	9,319
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,340	53,339	8,868	53,050	8,816
Forecast													
2003/04	15,773	13,882	18,364	48,020	1,109	49,128	322	49,450	5,413	54,863	9,726	54,574	9,672
2004/05	16,013	13,964	18,422	48,399	1,090	49,489	320	49,809	5,458	55,267	9,836	54,975	9,781
2005/06	16,306	14,165	18,405	48,877	1,110	49,987	320	50,307	5,522	55,829	9,973	55,534	9,917
2006/07	16,614	14,453	18,355	49,423	1,105	50,528	320	50,848	5,594	56,442	10,111	56,145	10,055
2007/08	16,921	14,794	18,440	50,155	1,124	51,279	322	51,601	5,686	57,287	10,289	56,984	10,232
2008/09	17,194	15,158	18,489	50,841	1,185	52,027	320	52,347	5,776	58,123	10,466	57,816	10,408
2009/10	17,472	15,515	18,521	51,509	1,203	52,712	320	53,032	5,862	58,894	10,635	58,582	10,576
2010/11	17,783	15,872	18,605	52,260	1,221	53,481	320	53,801	5,956	59,757	10,794	59,440	10,734
2011/12	18,109	16,216	18,692	53,018	1,239	54,257	322	54,578	6,050	60,628	10,961	60,307	10,900
2012/13	18,482	16,627	18,946	54,055	1,258	55,313	320	55,633	6,174	61,807	11,173	61,480	11,111
2013/14	18,856	17,014	19,185	55,056	1,278	56,334	321	56,655	6,294	62,949	11,379	62,618	11,316
2014/15	19,255	17,374	19,426	56,055	1,300	57,355	321	57,676	6,414	64,090	11,596	63,754	11,532
2015/16	19,636	17,738	19,718	57,092	1,319	58,411	323	58,734	6,536	65,270	11,817	64,928	11,752
2016/17	19,989	18,081	20,011	58,081	1,336	59,417	321	59,738	6,653	66,391	12,036	66,043	11,970
2017/18	20,390	18,475	20,273	59,138	1,352	60,490	321	60,811	6,778	67,589	12,263	67,235	12,195
2018/19	20,740	18,838	20,566	60,144	1,369	61,513	321	61,834	6,897	68,731	12,479	68,371	12,410
2019/20	21,122	19,241	20,869	61,232	1,386	62,618	323	62,940	7,025	69,965	12,707	69,599	12,637
2020/21	21,462	19,666	21,163	62,290	1,403	63,694	321	64,015	7,150	71,165	12,922	70,793	12,851
2021/22	21,813	20,139	21,483	63,435	1,421	64,856	321	65,177	7,285	72,462	13,160	72,084	13,087
2022/23	22,155	20,558	21,791	64,504	1,439	65,943	321	66,264	7,411	73,675	13,375	73,291	13,301
2023/24	22,569	21,029	22,114	65,712	1,457	67,168	323	67,491	7,553	75,044	13,614	74,654	13,539
Growth Rates:													
5 yrs 02/03-07/08	2.1%	1.5%	-0.2%	1.0%	0.9%	1.0%	0.5%	1.0%	5.6%	1.4%	3.0%	1.4%	3.0%
11 yrs 02/03-13/14	1.9%	2.0%	0.3%	1.3%	1.6%	1.3%	0.2%	1.3%	3.4%	1.5%	2.3%	1.5%	2.3%
21 yrs 02/03-23/24	1.9%	2.1%	0.8%	1.5%	1.5%	1.5%	0.1%	1.5%	2.7%	1.6%	2.1%	1.6%	2.1%

Note: Losses are assumed to be 4% Distribution and 8.1% Transmission

Table A7.6. 2003 BC Hydro, Low Scenario Load Forecast With Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1998/99	13,972	12,814	18,077	44,863	650	45,513	292	45,805	5,092	50,897	9,077	50,648	9,026
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,369	52,718	9,319
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,340	53,339	8,868	53,050	8,816
Forecast													
2003/04	15,502	13,809	18,171	47,483	1,109	48,592	322	48,914	5,353	54,267	9,621	53,997	9,570
2004/05	15,618	13,784	18,035	47,437	1,090	48,527	320	48,847	5,351	54,198	9,646	53,929	9,595
2005/06	15,792	13,848	17,889	47,530	1,110	48,640	320	48,960	5,373	54,333	9,706	54,065	9,655
2006/07	15,961	13,953	17,700	47,615	1,105	48,720	320	49,040	5,393	54,433	9,751	54,166	9,700
2007/08	16,147	14,128	17,641	47,916	1,124	49,040	322	49,362	5,436	54,798	9,842	54,527	9,790
2008/09	16,291	14,297	17,591	48,179	1,185	49,364	320	49,684	5,477	55,161	9,933	54,886	9,881
2009/10	16,477	14,498	17,498	48,474	1,203	49,677	320	49,997	5,520	55,517	10,025	55,237	9,972
2010/11	16,626	14,710	17,450	48,786	1,221	50,007	320	50,327	5,564	55,891	10,095	55,607	10,041
2011/12	16,772	14,874	17,355	49,002	1,239	50,241	322	50,563	5,597	56,160	10,153	55,871	10,098
2012/13	17,003	15,134	17,468	49,605	1,258	50,863	320	51,183	5,672	56,855	10,278	56,562	10,222
2013/14	17,242	15,329	17,563	50,135	1,278	51,413	321	51,734	5,738	57,472	10,388	57,175	10,331
2014/15	17,497	15,554	17,690	50,741	1,300	52,041	321	52,362	5,813	58,175	10,525	57,873	10,467
2015/16	17,739	15,721	17,797	51,257	1,319	52,576	323	52,899	5,877	58,776	10,642	58,469	10,583
2016/17	17,988	15,961	17,894	51,843	1,336	53,179	321	53,500	5,949	59,449	10,778	59,137	10,718
2017/18	18,237	16,196	18,009	52,442	1,352	53,794	321	54,115	6,023	60,138	10,911	59,820	10,850
2018/19	18,457	16,426	18,164	53,047	1,369	54,416	321	54,737	6,096	60,833	11,045	60,510	10,983
2019/20	18,696	16,657	18,299	53,652	1,386	55,038	323	55,361	6,169	61,530	11,175	61,201	11,112
2020/21	18,937	16,881	18,414	54,231	1,403	55,634	321	55,955	6,241	62,196	11,293	61,863	11,229
2021/22	19,160	17,122	18,504	54,786	1,421	56,207	321	56,528	6,309	62,837	11,412	62,498	11,347
2022/23	19,397	17,376	18,664	55,437	1,439	56,876	321	57,197	6,388	63,585	11,543	63,241	11,476
2023/24	19,639	17,626	18,767	56,032	1,457	57,489	323	57,812	6,462	64,274	11,660	63,924	11,592
Growth Rates:													
5 yrs 02/03-07/08	1.1%	0.6%	-1.0%	0.1%	0.9%	0.1%	0.5%	0.1%	4.6%	0.5%	2.1%	0.6%	2.1%
11 yrs 02/03-13/14	1.1%	1.0%	-0.5%	0.5%	1.6%	0.5%	0.2%	0.5%	2.6%	0.7%	1.4%	0.7%	1.5%
21 yrs 02/03-23/24	1.2%	1.2%	0.0%	0.8%	1.5%	0.8%	0.1%	0.8%	1.9%	0.9%	1.3%	0.9%	1.3%

Note: Losses are assumed to be 4% Distribution and 8.1% Transmission