Electric Load Forecast

Fiscal 2012 to Fiscal 2032

Load and Market Forecasting
Energy Planning and Economic Development
BC Hydro

2011 Forecast
December 2011

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Background and Context

BC Hydro is the third largest utility in Canada and serves 95 percent of British Columbia's population. BC Hydro's total energy requirements, including losses and sales to other utilities and non-integrated areas (NIAs), were 55,370 GWh in F2011[1]. Excluding the NIAs, the total integrated system energy requirements were 55,047 GWh[2]. The total integrated system peak demand in F2011 before weather adjustments and including losses and peak demand supplied by BC Hydro to other utilities was reported to be 10,203 MW excluding any load curtailments.

Load forecasting is central to BC Hydro's long-term planning, medium-term investment, and short-term operational and forecasting activities. BC Hydro's Electric Load Forecast is published annually for the purpose of providing decision-making information regarding "where, when and how much" electricity is expected to be required on the BC Hydro system. The forecast is based on several end-use and econometric models that use historical billed sales data up to March 31 of the relevant year, combined with a variety of economic forecasts and inputs from internal, government and third party sources.

BC Hydro's load forecasting activities are focused on the preparation of a number of term-specific and location-specific forecasts of energy sales and peak demand requirements in order to provide decision-making information for users. A variety of related products including monthly variance reports, inputs for revenue forecasts and load shape analyses, are produced to supplement the forecasts presented in this report.

Forecast Methodology

BC Hydro produces 21-year forecasts (remainder of current year plus a 20 year projection) for both energy and peak demand. These forecasts are compiled separately but undergo a number of checks to ensure consistency. The load forecasts are prepared before and after incremental Demand Side Management (DSM).

BC Hydro incorporates relatively certain loads and demand trends into its load forecast. Large potential loads such as Liquefied Natural Gas (LNG) have been specifically factored into the 2011 Load Forecast. BC Hydro is closely monitoring technological trends such as the future effects of electrification loads for possible inclusion into its base (Reference) load forecast. Similarly, BC Hydro includes verifiable information regarding specific customer loads in its load forecast in order to reflect possible reductions due to customer attrition.

The impacts of possible future electricity rate increases are also reflected in BC Hydro's load forecasts. Load reductions due to potential rate increases (i.e., Rate Impacts) are estimated and applied to the load forecasts. Load forecasts presented in this document are designated as either being 'before rate impacts', or 'with rate impacts'. Refer to Chapter 3 for more details on rate impacts.

The energy forecast is produced for each of the three major customer classes: residential, commercial and industrial. Sales to the three customer classes are combined with sales to other utilities to develop total BC Hydro sales estimates. These sales estimates are adjusted for system line losses resulting in total gross energy requirements. To determine gross energy requirements for the integrated system, sales and losses to all NIAs are excluded.

[1] BC Hydro's fiscal year end is March 31; thus, F2011 covers April 1, 2010 to March 31, 2011.
[2] The NIAs include the Purchase Areas, Zone II and Fort Nelson. A number of small communities located in the northern and southern areas of B.C. that are not connected to BC Hydro's electrical grid make up the Purchase Areas and Zone II.

Residential and Small Commercial

The residential sector forecast is the product of accounts and use per account. The account forecast is driven by projections of regional housing starts. The commercial sales forecast includes commercial general distribution loads, other commercial distribution loads such as irrigation and street lighting, and commercial transmission-connected loads such as pipelines and institutions such as universities. In terms of forecasting complexity, larger commercial accounts are forecast using forward-looking information that includes expected sector trends, whereas the forecasts for the smaller sales categories rely upon historical sales trends.

The residential use per account forecast and commercial general distribution sales forecasts (prior to including Rates Impacts, electric vehicles and adjustments for codes and standards) are developed with Statistically Adjusted End-Use (SAE) models. These models combine traditional regression-based forecasting with detailed end-use data to produce forecasts. The key drivers of these end-use models are regional economic variables (i.e., disposable income, commercial (GDP), employment, retail sales, income, population, etc.) and non-economic variables such as weather and average stock efficiency of the various end uses of electricity.

Large Commercial and Industrial

The industrial sector is made up of distribution and transmission-connected customers. The industrial distribution forecast is developed for a limited number of sub-sectors and uses GDP as the driver of future load growth. The forecasts for larger transmission-connected industrial and commercial customers are primarily done on an individual customer account basis and sector basis, utilizing specific customer and sector expertise from inside and outside of BC Hydro (e.g., consulting studies). BC Hydro applies a risk assessment to specific accounts within each sector to quantify their individual contribution to a total system forecast. These assessments are based customer-specific risk factors such as commodity prices, export markets, and First Nations/environmental issues.

For the mining sector, the forecast is developed using industrial sector reports from consultants, government mining reports, production forecasts and energy intensity ratios. BC Hydro applies risk adjustments to future mining project loads, which are intended to factor development risks. Some of the factors that inform these weights include the financial viability of projects; the status of environmental approvals and whether or not the potential mine proponent has formally applied to BC Hydro for electrical service.

For the oil and gas sector, BC Hydro employs two approaches to develop load forecasts, namely the top-down and the bottom-up methodology. For the top-down approach, BC Hydro uses internal and third party predictions of oil and gas production and energy intensities to create annual load forecasts. The bottom-up method involves the development of forecasts of customer-specific loads, which are then risk adjusted and summed to produce composite loads. The risk adjustment factors are informed by discussions with BC Hydro's key account managers, potential new customers, and government/industry experts.

New LNG facilities potentially represent the biggest additional loads on BC Hydro's system. The 2011 Load Forecast factors in additional demand from two potential LNG projects on the North Coast of B.C., specifically, the Douglas Channel LNG project (risk adjusted as explained above) and the Kitimat LNG project. The total LNG Load is expected to require about 5,000 GWh/year of energy for refrigeration and gas compression. From this point forward, both Douglas Channel and Kitimat LNG Load will be referred to as the Initial LNG Load.

LNG production is a relatively simple process in which the significant majority of work energy is for driving compression in the refrigeration loops, in a process not dissimilar to home-based refrigerators or air conditioning units. BC Hydro has obtained information with respect to LNG demand requirements from potential project proponents and industry publications/studies.

The Initial LNG Load is treated distinctly in the 2011 Forecast, in that it is a very large load that would have a profound impact on BC Hydro and its planning processes. Therefore, duplicate load forecasts are presented in this document, designated as either being 'before Initial LNG Load', or 'with Initial LNG Load'.

Peak Demand

The peak demand forecast is produced for each of BC Hydro's distribution substations and for individual transmission customer accounts. Distribution substation forecasts are prepared for 15 distribution planning areas using energy forecasts and other drivers such as smaller distribution loads or spot loads. These substation forecasts are further aggregated on a coincident basis to develop a total system coincident distribution peak forecast. Relevant production and account information from the larger transmission energy forecast forms the basis for peak forecasts for each of BC Hydro's large transmission customers. The transmission peak forecasts for each account are aggregated on a coincident basis to develop a total system coincident transmission peak forecast. The total system peak forecast includes the system coincident distribution, transmission, peak demand transfers from BC Hydro to other utilities and system transmission losses.

Comparative Load Forecasts

The 2011 Load Forecast was prepared in the fall of 2011 as part of BC Hydro's annual forecasting cycle. The forecast methodology is similar to that used for the 2008 Load Forecast, which was reviewed by the British Columbia Utilities Commission (BCUC) in the 2008 LTAP proceeding. The major changes in methodology since the 2008 Load Forecast include:

1. A portion of the industrial distribution sector is now forecast on a sub-sector basis (i.e., mining, oil and gas, wood) versus the previous use of a regression analysis for the entire sector. This change has enhanced the Load Forecast by improving upon the regional and total system load projections by incorporating load drivers such as the pine beetle infestation and specific industrial customer expansions;
2. Electric vehicle (EV) load is now included in the 2011 Load Forecast. The demand estimates are the same as for the 2010 Load Forecast with 38 GWh in F2017. By F2032, the EV load rises to 2,342 GWh; and
3. The potential for DSM double counting issue was raised in the 2008 LTAP.[3] Adjustments to the load forecast for DSM double counting were first made in the 2009 Load Forecast, and have been continued in the 2010 and 2011 Load Forecasts. Appendix 5 shows the annual adjustments for the overlap in codes and standards.

In addition to the EV and double counting adjustments, the 2011 Load Forecast projects energy and peak demand requirements prior to incremental DSM but inclusive of the impact of varying electricity rates. This is consistent with the 2010 Load Forecast although much of the data in last year's forecast was presented without rate impacts, in order to isolate and highlight pure load growth.

BC Hydro's long-term rate increase projection reflected in the 2011 Load Forecast is lower than assumed in the 2010 Load Forecast. As such, the rate impact (i.e. load reduction from average rate increases) is relatively lower. The total rate impact for all residential, commercial and industrial customers is 309 GWh lower in F2012, 542 GWh lower in

[3] Refer to 2008 LTAP Decision, Directive 6, page 180. BC Hydro's load forecasting models assume the U.S. Energy Information Administration's (EIA) level of end-use efficiencies. These EIA efficiency levels form the basis of the double counting which results in a lower forecast. In addition, DSM savings due to codes and standards are subtracted in the Load Forecast.

F2017, 263 GWh lower in F2023 and 407 GWh lower in F2031 compared to the 2010 Load Forecast.

Residential Forecast

Load in the residential sector, while subject to short-term variability due to weather events, tends to exhibit more predictable growth compared to the other sectors. The residential sector is forecast on a regional basis with the key forecast features including the following:

- Electricity Use – BC Hydro's residential sector currently consumes about 35 percent of BC Hydro's total annual firm billed sales. This electricity is used to provide a range of services (end uses) including space heating, water heating, refrigeration, and miscellaneous plug-in load which includes computer equipment and home entertainment systems.
- Drivers – The drivers of the residential forecast are number of accounts and average annual use per account. Growth in the total number of accounts is driven largely by growth in housing starts. The use per account forecast is developed on a regional basis from the SAE models. The drivers of the model include economic variables such as disposable income, weather and average stock efficiency of residential end uses of electricity.
- Trends – The residential sales forecast is below the 2010 Load Forecast for all years of the forecast primarily from lower predicted housing starts growth and therefore accounts growth is expected to be slower relative to the previous forecast. The energy impact of EVs is the same as the 2010 forecast while adjustments for DSM/load integration are lower in this year's forecast. The 21-year compound growth rate[4], before DSM and with Rate Impacts, is projected to be 2.0 percent per annum.

Refer to Chapter 6 for a detailed description of the residential forecast.

Commercial Forecast

BC Hydro's commercial sector encompasses a wide variety of commercial and publicly-provided services, including irrigation, street lighting and BC Hydro's own use. The most diverse commercial segment consists of customers who operate a range of facilities such as office buildings, retail stores and institutions (i.e., hospitals and schools) provided at distribution voltages. It also includes transportation facilities in the form of pipelines and bulk transportation terminals which receive electricity at transmission voltages.

The key features of the commercial forecast include the following:

- Electricity Use – BC Hydro's commercial sector currently consumes 31 percent of BC Hydro's total annual firm billed sales. On the distribution system, electricity is used to provide a range of services such as lighting, ventilation, heating, cooling, refrigeration and hot water. These needs vary considerably between different types of buildings and types of loads.
- Drivers – Consumption in commercial distribution sales is closely tied with economic activity in the province. Key drivers for the commercial distribution sales include retail sales, employment and commercial output. Other drivers of the end use forecasting model for this sector include weather and commercial end use stock average efficiency forecasts. For the commercial transmission sector, individual customer load projections are developed. Historical load trends are a good indicator of future trends for accounts with relatively stable loads.
- Trends – Electricity consumption in the commercial sector can vary considerably from year to year, reflecting the level of activity in B.C.'s service sector. Commercial distribution sales have slowed in recent years as have provincial and global economic

[4] Unless otherwise noted, all growth rates are calculated as annual compound growth rates.

growth. As such, the 2011 commercial forecast is below last year's forecast in the initial period of the forecast. Towards the middle and long term period of the forecast, the 2011 Forecast is above 2010 Forecast. This reflects revised economic drivers of the commercial general distribution load as well expected gains in efficiency of commercial general distribution end uses. Over a 21-year period, the 2011 Load Forecast growth rate, before DSM and with Rate Impacts, is 2.0 percent per annum.

Industrial Forecast

BC Hydro's industrial sector is concentrated in a limited number of industries, the most important of which are pulp and paper, wood products, chemicals, metal mining, coal mining and oil and gas sector loads. The remaining industrial load is made up of a large number of small and medium sized manufacturing establishments. Key features of the industrial forecast include the following:

- Electricity Use – BC Hydro's industrial sector currently consumes 31 percent of BC Hydro's total annual firm billed sales. This electricity is used in a variety of applications including fans, pumps, compression, conveyance, processes such as cutting, grinding, stamping and welding and electrolysis. At distribution voltages, wood manufacturing is the major component of industrial sales.
- Drivers – Industrial electricity consumption is tied closely with the level of economic activity in the province, market conditions and prices, and world and domestic events that impact product demand. The key drivers of the forecasts are production, intensity levels, third party industry reports and changes in customer plant operations as identified by BC Hydro's Key Account Managers. Probability assessments are undertaken for existing accounts and new accounts to determine specific customer load projections.
- Trends – Electricity consumption in the industrial sector is quite volatile, driven substantially by external economic conditions that affect commodity markets. The current forecast is lower in the short term than the 2010 Load Forecast. In the medium term, the current industrial forecast is above last year's forecast due to higher load expectations in the mining sector. In the long term, current forecast is below the 2010 Load Forecast. The 21-year growth rate in the current forecast, before DSM and with Rate Impacts, and excluding Initial LNG Load, is 1.8 percent per annum.

Refer to Chapter 8 for a detailed description of the industrial forecast.

Peak Demand

Peak demand is composed of the demand for electricity at the distribution level, transmission level plus inter-utility transfers and transmission losses on the integrated system. Key features of the peak forecast include the following:

- Electricity Use – Peak demand is forecast as the maximum expected one-hour demand during the year. For BC Hydro's load, this event occurs in the winter with the peak driven particularly by space heating load. As with the 2010 Load Forecast, BC Hydro's peak forecast is based on normalized weather conditions, which is the rolling average of the coldest daily average temperature over the most recent 30 years.
- Drivers – Key drivers of electricity peak include the level of economic activity, number of accounts, employment and the other discrete developments such as new shopping malls, waste treatment plants or industrial facilities that drive substation peak demand.
- Trends – BC Hydro's total system peak forecast has grown less than 1 percent over the last two fiscal years. The slowdown in the economy has impacted growth both in the distribution and transmission peak demand. The current total system peak forecast is below the 2010 Forecast for the immediate initial years of the forecast as account growth projection is lower in the current forecast. Over the medium and long term, the

total system peak forecast is above the 2010 Forecast. This is driven by a revised load expectation for oil and gas and mining loads.

- Refer to Chapter 10 for a detailed description of the peak demand forecast

Key Forecast Results

The 2011 Load Forecast contains the following results for the industrial sector:

- Mining – compared to the 2010 Forecast, the current projection for mining is higher throughout most of the forecast; metal mining is significantly higher in the medium term due to large existing mines expected to extend their activity past the previously announced shutdown dates.
- Forestry – current forecast is significantly below the 2010 Load Forecast. Most of the decrease in forestry falls in the pulp and paper sector due to lower production expectations for certain product grades relative to the 2010 Forecast.
- Chemical – most of the large chemical customers in B.C. provide inputs into the pulp and paper operations for bleaching. Beyond these domestic opportunities, chemical producers have expanded into other export markets. The current outlook for the large chemical sector is marginally lower than last year's forecast.
- Oil and Gas – sales to producers and processors of conventional and unconventional oil and gas (particularly shale gas) will make up the majority of sales to this segment over next 20 years. Major factors leading to the changes in sales are revised production forecasts, particular for the unconventional gas resource in northeast B.C. Refer to Appendices 3.1 and 3.2 for more information regarding this sector.

The most significant potential new load in the 2011 Load Forecast is Initial LNG, which would represent the largest single incremental load in BC Hydro's history. This load is categorized as industrial sector load, for reasons indicated earlier.

BC Hydro's 2011 Load Forecast with Initial LNG load factors in potential additional demand from two potential LNG projects on the north coast of B.C., where electricity could be used to refrigerate natural gas to produce LNG for export. The two are the Douglas Channel LNG project, and the two-phase Kitimat LNG project. The Initial LNG Load is expected to require approximately 5,000 GWh/year, primarily for refrigeration and gas compression. If the facility goes into operation in 2015, it would increase BC Hydro's electricity supply requirements by approximately seven percent. Due to the significant size of this customer load, and the policy and technical issues associated with BC Hydro serving this load, the 2011 Load Forecast is presented with and without the Initial LNG loads.

Beyond LNG, the other significant change in the 2011 Load Forecast is that energy and peak demand requirements for unconventional gas producers within the Horn River Basin are not included in the 2011 reference load projections for Fort Nelson. BC Hydro has constructed scenarios that examine various Horn River shale gas play load requirements and alternatives on how to supply these loads. These scenarios are examined in BC Hydro's Integrated Resource Planning process.

Reference Energy and Peak Forecasts

Table 1 provides a summary of historical and forecast of sector sales, total energy requirements and total peak demand requirements for selected years before DSM and with Rate Impacts. The forecasts include in the impact of EVs and an adjustment for overlap in codes and standards but do not include Initial LNG Load.

Table 2 provides a summary of historical and forecast of sector sales, total energy requirements and total peak demand requirements for selected years before DSM and with Rate Impacts. The forecasts include the impact of EVs, an adjustment for overlap in codes and standards, as well as Initial LNG Loads.

Table E1. Reference Energy and Peak Forecast before DSM and With Rate Impacts (Excluding Initial LNG Load)

Fiscal Year	BC Hydro Residential (GWh)	BC Hydro Commercial (GWh)	BC Hydro Industrial (GWh)	Total Firm Sales* (GWh)	Total Integrated System	
					Energy Requirements (GWh)	Peak Demand** (MW)
F2011	17,898	15,896	15,785	50,869	55,047	10,335
F2012	18,199	15,964	16,433	51,891	56,803	10,651
F2016	19,711	17,811	20,917	60,280	65,796	12,140
F2022	22,218	20,034	23,103	67,233	73,419	13,197
F2027	24,565	21,635	21,899	70,015	76,573	14,021
F2032	27,150	24,069	22,931	76,106	83,309	15,174
5 years: F2011-16	1.9%	2.3%	5.8%	3.5%	3.6%	3.3%
11 years: F2011-22	2.0%	2.1%	3.5%	2.6%	2.7%	2.2%
21 years: F2011-32	2.0%	2.0%	1.8%	1.9%	2.0%	1.8%

* Total firm sales includes sales to all residential, commercial and industrial customers and sales to all other utilities including Seattle City Light, City of New Westminster and FortisBC and Hyder.

** Peak Demand for F2011 is weather normalized.

Table E2. Reference Energy and Peak Forecast before DSM and With Rate Impacts (Including Initial LNG Load)

Fiscal Year	BC Hydro Residential (GWh)	BC Hydro Commercial (GWh)	BC Hydro Industrial (GWh)	Total Firm Sales* (GWh)	Total Integrated System	
					Energy Requirements (GWh)	Peak Demand** (MW)
F2011	17,898	15,896	15,785	50,869	55,047	10,335
F2012	18,199	15,964	16,465	51,923	56,838	10,656
F2016	19,711	17,811	22,001	61,364	66,956	12,439
F2022	22,218	20,034	28,039	72,169	78,700	13,878
F2027	24,565	21,635	26,834	74,951	81,854	14,701
F2032	27,150	24,069	27,866	81,042	88,590	15,855
5 years: F2011-16	1.9%	2.3%	6.9%	3.8%	4.0%	3.8%
11 years: F2011-22	2.0%	2.1%	5.4%	3.2%	3.3%	2.7%
21 years: F2011-32	2.0%	2.0%	2.7%	2.2%	2.3%	2.1%

* Total firm sales includes sales to all residential, commercial and industrial customers and sales to all other utilities including Seattle City Light, City of New Westminster and FortisBC and Hyder.

** Peak Demand for F2011 is weather normalized.

1 Introduction

BC Hydro's Load Forecast is typically published annually. The Load Forecast consists of a 21-year forecast (remainder of the current year plus a 20-year projection) for future energy and peak demand requirements. These forecasts focus on the annual Reference Load Forecast or the most likely electricity demand projections that are used for planning future energy and peak supply requirements.

The Load Forecast is used to provide decision-making support for several aspects of BC Hydro's business including: the Integrated Resource Plan, revenue requirements, rate design, system planning and operations and service plan.

Ranges in the load forecasts, referred to as uncertainty bands, are developed using simulation methods. These bands represent the expected ranges around the annual Reference load forecasts at certainty levels of statistical confidence. These forecasts are produced because there is uncertainty in the variables that predict future loads and in the predictive powers of the forecasting models.

The Reference energy forecast consists of a sales forecast for three main customer sectors (residential, commercial and industrial) plus the other utilities supplied by BC Hydro. The Reference Total Gross energy requirements forecast consists of the sector sales forecast, other utility sales forecast plus total line losses.

The sales forecast is developed by analyzing and modeling the relationships between energy sales and the predictors of future sales, which are referred as forecast drivers. Drivers consist of both economic variables and non-economic variables. Economic variables include GDP, housing starts, retail sales, employment and electricity prices (rates). Non-economic variables include weather and average stock efficiency of various residential and commercial end uses of electricity.

The rate impacts are reflected in the Reference forecasts; these impacts consist of the effect on load due to potential electricity rate changes under flat rate structures or a single tier rate design[5]. Savings or reductions in the load due to changes in rate structures are considered to be part of BC Hydro's 20-year DSM Plan. These savings are not included in the load forecasts contained in this document but are contained in other applications such as BC Hydro's Revenue Requirements Application.

The total Reference peak forecast consists of peak demands for BC Hydro's coincident distribution substations, large transmission-connected customers and other utilities, along with total transmission losses. The distribution peak demand forecast is developed by analyzing and modelling the relationship between substation peak demand and economic variables. Distribution peak forecasts are prepared under average cold weather conditions or a design temperature. The transmission peak demand is based on estimating the future demands of larger customers which are driven by future market conditions and company-specific production plans.

BC Hydro continuously attempts to improve the accuracy of its forecasting process by monitoring trends in forecasting approaches and tracking developments that may affect the load forecasts. Forecasts are continually monitored and compared to sales, and are adjusted for variances. Additionally, the load forecasts are adjusted if new information on forecast drivers becomes available during the year they are developed.

For continuity between the 2010 Load Forecast and the 2011 Load Forecast, load estimates of EVs are shown in Appendix 4, and adjustment for double counting in codes

[5] The electricity price elasticity of demand used to develop the rate impacts is assumed to be -0.05 for all rate classes. Additional rate-induced savings resulting from stepped rates (conservation rates) are counted separately as DSM savings.

and standards is shown in Appendix 5. These load categories are necessarily included in the Reference load forecast.

Comparisons between the 2010 and the 2011 Load Forecasts for the Residential and Commercial section are with rate impacts. The Industrial section is compared before rate impacts so as to highlight the key differences between the two vintages of forecasts.

New LNG facilities, such as Initial LNG Load, potentially represent the single biggest additional demands on BC Hydro's system over the next 20 years. Of these projects, the Initial LNG Load is the largest potential load at approximately 5,000 GWh/year. The 2011 Reference Load Forecast is presented excluding and including the Initial LNG Load.

2 Regulatory Background and Current Initiatives

The British Columbia Utilities Commission (BCUC), various intervenors and other stakeholders have reviewed BC Hydro's Electric Load Forecasts in past years by way of the following regulatory review processes:

- 2003 Vancouver Island Generation Project – Certificate of Public Convenience and Necessity (CPCN) Application
- F2005 and F2006 Revenue Requirements Application (RRA)
- 2004 Vancouver Island Call for Tenders – Electricity Purchase Agreement (EPA)
- F2006 Call for Tenders
- F2007 and F2008 RRA
- 2006 Integrated Electricity Plan (IEP) and Long Term Acquisition Plan (LTAP)
- 2008 LTAP
- F2009 and F2010 RRA
- 2009 Waneta Transaction
- F2011 RRA

There were no major BCUC decisions or directives that impact the development of the 2011 Load Forecast other than the directives emanating from the 2008 LTAP. In its decision on the 2008 LTAP, the BCUC issued two directives related to the 2008 Load Forecast. Actions taken in response to these two directives are summarized in Table 2.1. BC Hydro's 2010 Annual Load Forecast document addresses these two directives in detail. At this time, BC Hydro believes that there is no additional work required to fulfill Directive 7.

For the 2011 Load Forecast, BC Hydro has continued its work on load forecast DSM/Load Integration and made adjustments to its current load forecast to account for potential overlap between the Load Forecast and the DSM Plan estimates for codes and standards. Please see Appendix 5 for further details on the adjustments.

Table 2.1. BCUC 2008 LTAP Directives and Actions

Directives from the 2008 LTAP	Actions
Directive # 6: The Commission Panel accepts BC Hydro's 2008 Load Forecast Update for the purposes of its review of the 2008 LTAP. The Commission Panel also notes that BC Hydro agrees with IPPBC that there is some potential for double counting of DSM in the forecasting coefficients and requires BC Hydro to address this in its next LTAP.	In a letter dated November 1, 2010 to the BCUC, BC Hydro provided its view on the appropriate disposition of directives from the 2008 LTAP and BCTC capital plans. BC Hydro indicated that the issue raised in Directive 6 would be addressed in the 2010 Load Forecast, in the 2011 Integrated Resource Plan and if appropriate in growth project-related CPCN and/or Utilities Commission Act subsection 44.2(1)(a) DSM expenditure schedule filings with the BCUC. BC Hydro's load forecasting models assume U.S. Energy Information Administration (EIA) level of end-use efficiencies. In addition, DSM savings due to codes and standards are subtracted from the load forecast, where the baseline efficiency may be higher than that of the EIA. Thus, double counting is the result BC Hydro reviewed codes and standards contained in the 20-year DSM Plan against the EIA documentation and identified which individual codes and standards result in double counting. An adjustment was made to the 2010 and 2011 Load Forecasts to account for this overlap. See Appendix 5 for additional details.

3 Forecast Drivers, Data Sources and Assumptions

3.1. Forecast Drivers

Table 3.1 provides a summary of the load forecast components and key data drivers.

Table 3.1. Key Forecast Drivers

Forecast Component	Data
1. Residential Forecast	• Historical number of accounts • Housing starts and personal income • Heating Degree Day (HDD) and Cooling Degree Day (CDD) • Appliance saturation rates from Residential End Use Survey and efficiency data from the EIA
2. Commercial (Distribution) Forecast	• Billing data • Commercial Output • Employment and Retail Sales • HDD and CDD • End use saturation rates from Commercial End Use Survey and efficiency data from the EIA
3. Industrial Distribution Forecast	• GDP • Production Forecast
4. Large Commercial and Industrial Transmission Forecast	• Billing data • GDP • Forecasts from consultants • Information from various reports and Key Account Managers
5. Non-Integrated Area (NIA) Forecast	• Billing data • Historical number of accounts • Local conditions in the short-term • Population forecasts
6. Peak Forecast	• Distribution energy forecast and housing starts • Weather data and load research data on load shape

3.2. Data Sources

Information on the sources and uses of the data is shown in Table 3.2.

Table 3.2. Data Sources for the 2011 Load Forecast

Variable	Application	Forecast Period	Source
GDP	• Industrial distribution energy forecast	• 2011-2014 • 2015-2031	• BC Ministry of Finance - First Quarterly Report, Sept. 8 2011 • Stokes Economic Consulting, June 2011
GDP	• Commercial and Industrial transmission energy forecast	• 2011-2014 • 2015-2031	• BC Ministry of Finance - First Quarterly Report, Sept. 8 2011 • Stokes Economic Consulting, June 2011
Housing Starts	• Residential accounts forecast	• 2011-2031	• Stokes Economic Consulting, June 2011
Employment, Retail Sales and Commercial Output	• Commercial distribution sales • Distribution peak	• 2011-2031	• Stokes Economic Consulting, June 2011

3.3. Growth Assumptions

The growth assumptions for key drivers used in the Reference load forecast are shown in Table 3.3 below.

Table 3.3. Growth Assumptions (Annual rate of growth)

Fiscal Year	Residential Accounts (%)	Calendar Year	Employment (%)	Retail Sales (%)	Real GDP (%)
Actual					
F2011	1.3	2010	1.5	3.9	3.8
Forecast					
F2012	1.5	2011	2.2	2.8	2.0
F2013	1.5	2012	2.4	2.4	2.3
F2014	1.5	2013	2.1	2.4	2.4
F2015	1.6	2014	1.9	2.3	2.4
F2016	1.7	2015	2.0	2.4	4.2
F2017	1.7	2016	1.7	2.6	4.6
F2018	1.8	2017	1.4	2.6	4.6
F2019	1.8	2018	1.6	3.0	5.4
F2020	1.8	2019	1.0	2.7	4.3
F2021	1.7	2020	0.7	2.3	3.0
F2022	1.6	2021	0.6	2.0	1.5
F2023	1.5	2022	0.5	1.8	1.5
F2024	1.5	2023	0.6	1.8	1.4
F2025	1.4	2024	0.5	1.6	1.3
F2026	1.4	2025	0.6	1.7	1.4
F2027	1.3	2026	0.6	1.8	1.3
F2028	1.3	2027	0.7	2.0	1.4
F2029	1.2	2028	0.9	2.1	1.5
F2030	1.2	2029	1.0	2.3	1.7
F2031	1.2	2030	0.9	2.2	1.5
F2032	1.1	2031	0.9	2.1	1.4

3.4. Rate Impact Assumptions

The impacts of possible future electricity rate increases are also reflected in BC Hydro’s load forecasts. These changes are termed “Rate Impacts” and in the past have been referred to as “natural conservation from electricity rate changes”.[6] The two main assumptions behind the Rate Impacts are: (i) all customers are on a single tier rate structure; and (ii) the electricity price elasticity is -0.05 for all customer classes. These assumptions are consistent with those used to develop the 2008 Load Forecast contained in BC Hydro’s 2008 Long-Term Acquisition Plan (LTAP) Evidentiary Update and all subsequent BC Hydro load forecasts. Reductions in load for future rate increases (i.e., Rate Impacts) are estimated using BC Hydro’s Monte Carlo uncertainty model.

[6] Conservation induced by average rate increases (including rate riders) is referred to as "natural conservation" whereas incremental conservation induced by annual rate structure changes is known as "rate structure conservation". The sum of the two is counted as total conservation. In BC Hydro’s load forecast, "natural conservation" is included in the before-DSM load forecast, and "rate structure conservation" is included in the estimate of DSM savings.

4 Comparison of 2010 and 2011 Load Forecasts

4.1. Integrated System Gross Energy Requirements before DSM with Rate Impact

Tables 4.1 and 4.2 compare the 2011 Reference forecast integrated system gross energy requirements with the 2010 Load Forecast, without and with the Initial LNG Load, respectively. Both the 2010 and 2011 forecasts are before DSM, with rate impacts, and inclusive of the impact of electric vehicles (EVs) and adjustments for Load Forecast/DSM overlap in codes and standards.

Table 4.1 Comparison of Integrated System Gross Energy Requirements before DSM with Rate Impacts (excluding Initial LNG Load)

Fiscal Year	2011 Forecast (GWh)	2010 Forecast (GWh)	2011 Forecast minus 2010 Forecast (GWh)	Change over 2010 Forecast (percent)
Actual				
F2006	57,296	57,296	-	-
F2007	57,982	57,982	-	-
F2008	58,735	58,735	-	-
F2009	57,381	57,381	-	-
F2010	55,220	55,220	-	-
F2011	55,047	56,922*	-1,875	-3.3%
Forecast				
F2012	56,803	59,487	-2,684	-4.5%
F2013	59,260	61,391	-2,132	-3.5%
F2014	61,743	63,793	-2,050	-3.2%
F2015	63,895	66,567	-2,672	-4.0%
F2016	65,796	68,065	-2,269	-3.3%
F2017	67,457	68,912	-1,455	-2.1%
F2018	69,055	69,730	-675	-1.0%
F2019	70,432	70,644	-212	-0.3%
F2020	71,659	70,867	792	1.1%
F2021	72,476	71,679	797	1.1%
F2022	73,419	72,661	758	1.0%
F2023	74,171	73,705	466	0.6%
F2024	75,164	74,952	212	0.3%
F2025	75,860	76,043	-183	-0.2%
F2026	75,544	77,162	-1,618	-2.1%
F2027	76,573	78,326	-1,753	-2.2%
F2028	77,766	79,387	-1,622	-2.0%
F2029	78,911	80,401	-1,490	-1.9%
F2030	80,315	81,402	-1,088	-1.3%
F2031	82,075	82,467	-392	-0.5%
F2032	83,309			

* = forecast

Table 4.2. Comparison of Integrated System Gross Energy Requirements before DSM with Rate Impacts (including Initial LNG Load)

Fiscal Year	2011 Forecast (GWh)	2010 Forecast (GWh)	2011 Forecast minus 2010 Forecast (GWh)	Change over 2010 Forecast (percent)
Actual				
F2006	57,296	57,296	-	-
F2007	57,982	57,982	-	-
F2008	58,735	58,735	-	-
F2009	57,381	57,381	-	-
F2010	55,220	55,220	-	-
F2011	55,047	56,922*	-1,875	-3.3%
Forecast				
F2012	56,838	59,487	-2,648	-4.5%
F2013	59,285	61,391	-2,106	-3.4%
F2014	61,768	63,793	-2,025	-3.2%
F2015	63,983	66,567	-2,584	-3.9%
F2016	66,956	68,065	-1,109	-1.6%
F2017	71,258	68,912	2,345	3.4%
F2018	74,336	69,730	4,606	6.6%
F2019	75,713	70,644	5,069	7.2%
F2020	76,940	70,867	6,073	8.6%
F2021	77,757	71,679	6,078	8.5%
F2022	78,700	72,661	6,039	8.3%
F2023	79,452	73,705	5,747	7.8%
F2024	80,445	74,952	5,493	7.3%
F2025	81,141	76,043	5,098	6.7%
F2026	80,825	77,162	3,663	4.7%
F2027	81,854	78,326	3,527	4.5%
F2028	83,047	79,387	3,659	4.6%
F2029	84,192	80,401	3,791	4.7%
F2030	85,595	81,402	4,193	5.2%
F2031	87,356	82,467	4,889	5.9%
F2032	88,590			

Note. * = forecast

4.2. Total Integrated Peak Demand before DSM with Rate Impacts

Tables 4.3 and 4.4 compare the 2011 Reference forecast total integrated peak demand requirements with the 2010 Load Forecast. Both the 2010 and 2011 forecasts are before DSM, with rate impacts, and inclusive of the impact of electric vehicles (EVs) and adjustments for Load Forecast/DSM overlap in codes and standards.

Table 4.3. Comparison of Integrated System Peak Demand before DSM with Rate Impacts (excluding Initial LNG Load)

Fiscal Year	2011 Forecast (GWh)	2010 Forecast (GWh)	2011 Forecast minus 2010 Forecast (GWh)	Change over 2010 Forecast (percent)
Actual				
F2006	9,617	9,617	-	-
F2007	10,371	10,371	-	-
F2008	9,861	9,861	-	-
F2009	10,297	10,297	-	-
F2010	10,112	10,112	-	-
F2011*	10,335	10,580**	-245	-2.3%
Forecast				
F2012	10,651	11,078	-427	-3.9%
F2013	11,026	11,338	-312	-2.7%
F2014	11,505	11,681	-175	-1.5%
F2015	11,832	12,066	-233	-1.9%
F2016	12,140	12,323	-183	-1.5%
F2017	12,389	12,484	-94	-0.8%
F2018	12,558	12,627	-69	-0.5%
F2019	12,737	12,762	-25	-0.2%
F2020	12,923	12,899	24	0.2%
F2021	13,053	12,983	69	0.5%
F2022	13,197	13,160	37	0.3%
F2023	13,382	13,352	29	0.2%
F2024	13,579	13,554	25	0.2%
F2025	13,775	13,778	-2	0.0%
F2026	13,891	13,966	-75	-0.5%
F2027	14,021	14,194	-173	-1.2%
F2028	14,232	14,456	-224	-1.5%
F2029	14,436	14,661	-224	-1.5%
F2030	14,673	14,867	-194	-1.3%
F2031	14,945	15,096	-151	-1.0%
F2032	15,174			

* For F2011, the weather normalized peak is 10,335 MW.

** = forecast

Table 4.4. Comparison of Integrated System Peak Demand before DSM with Rate Impacts (including Initial LNG Load)

Fiscal Year	2011 Forecast (GWh)	2010 Forecast (GWh)	2011 Forecast minus 2010 Forecast (GWh)	Change over 2010 Forecast (percent)
Actual				
F2006	9,617	9,617	-	-
F2007	10,371	10,371	-	-
F2008	9,861	9,861	-	-
F2009	10,297	10,297	-	-
F2010	10,112	10,112	-	-
F2011*	10,335	10,580**	-245	-2.3%
Forecast				
F2012	10,656	11,078	-422	-3.8%
F2013	11,030	11,338	-308	-2.7%
F2014	11,509	11,681	-172	-1.5%
F2015	11,845	12,066	-221	-1.8%
F2016	12,439	12,323	116	0.9%
F2017	13,070	12,484	586	4.7%
F2018	13,238	12,627	611	4.8%
F2019	13,418	12,762	656	5.1%
F2020	13,604	12,899	704	5.5%
F2021	13,733	12,983	750	5.8%
F2022	13,878	13,160	717	5.5%
F2023	14,062	13,352	710	5.3%
F2024	14,259	13,554	705	5.2%
F2025	14,456	13,778	678	4.9%
F2026	14,571	13,966	606	4.3%
F2027	14,701	14,194	508	3.6%
F2028	14,913	14,456	457	3.2%
F2029	15,117	14,661	456	3.1%
F2030	15,354	14,867	486	3.3%
F2031	15,625	15,096	529	3.5%
F2032	15,855			

* For F2011, the weather normalized peak is 10,335 MW.

** = forecast

5 Sensitivity Analysis

5.1. Background

Future electricity consumption is fundamentally uncertain and dependent on many variables such as economic activity, weather, electricity rates and DSM. The future impact of these variables on load is characterized by significant uncertainty. Moreover load is affected by extraordinary events such as strikes, trade disputes, pine beetle infestations and volatility in commodity markets. Additionally, world events such as recent economic crises, wars and revolutions may impact electricity demand.

BC Hydro tries to quantify the uncertainty in future load as much as possible by developing accurate, reliable and stable models that specify the relationship between load and its key drivers, and by using reliable and credible sources for forecasts of the key drivers of load.

BC Hydro uses a Monte Carlo model to estimate the potential distribution of future loads, and to represent this against the Reference load forecast (see Appendix 2). This model produces high and low uncertainty bands for each customer category around the Reference forecast by examining the impact on load from the uncertainty in a set of key drivers.

The major causal factors used by the model are: economic growth rate (measured by GDP), the electricity rates charged by BC Hydro to its customers, the effective energy reduction achieved by DSM programs, the sales response to electricity rate changes (price elasticity) and weather (reflected by heating degree-days). Probability distributions are assigned to each of these causal factors, and a distribution is assigned to a residual uncertainty variable. As with the 2010 Load Forecast, BC Hydro added to the Monte Carlo a probability distribution for electric vehicles (EVs) and DSM/ load forecast integration on codes and standards[7].

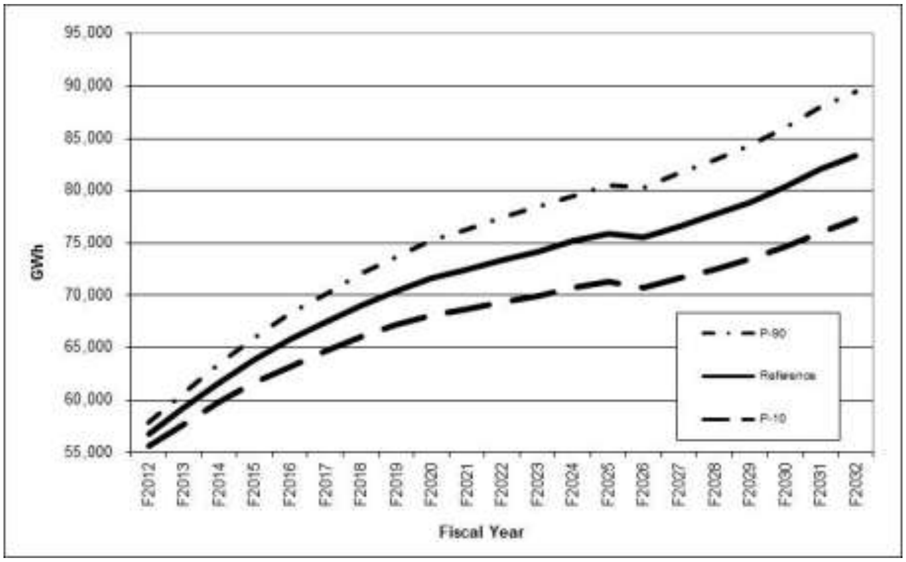
The Monte Carlo model uses simulation methods to quantify and combine the probability distributions, reflecting the relationships between the five causal factors and electricity consumption. A probability distribution for the load forecast is thus obtained which shows the likelihood of various load levels resulting from the combined effect of the input variables. This distribution implies the following confidence interval bands:

- Low band: There is a 10 per cent chance that the outcome will be below this value in a particular year.
- High band: There is a 10 per cent chance that the outcome will exceed this value in a particular year.

The high and low load forecasts before DSM with rate impacts (excluding the Initial LNG Load) are shown in Figures 5.1 and 5.2. The high and low total peak forecasts contained in these tables are based on the ratios of the total energy requirements for the Reference forecast to the high and low uncertainty bands.

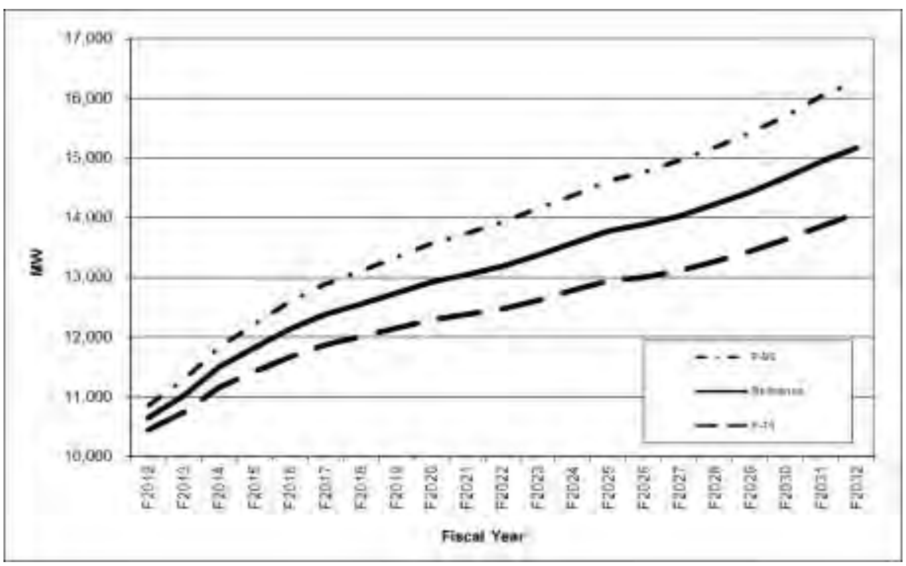
[7] See Appendix 2 for additional details on modifications to the Monte Carlo model.

Figure 5.1 High and Low Bands for Integrated System Energy Requirements before DSM with Rate Impacts (excluding Initial LNG Load)



Note: 2011 Reference Forecast in the figure above does not include Initial LNG load

Figure 5.2 High and Low Bands for Integrated System Peak Demand before DSM with Rate Impacts (excluding Initial LNG Load)



Note: 2011 Reference Forecast in the figure above does not include Initial LNG Load

6. Residential Forecast

6.1. Sector Description

The residential sector currently comprises about 35% of BC Hydro's total annual sales. This electricity is used to provide a range of services for customers (referred to as "end-uses"). Examples of residential end-uses of electricity are space heating, water heating, refrigeration, and miscellaneous plug-in loads which include computer equipment and home entertainment systems. Since space and water heating loads are dependent on the outside temperature, residential sales can be strongly affected by the weather.

Of the 1.65 million residential accounts served by BC Hydro at the end of F2011, 58% are located in the Lower Mainland, 21% are on Vancouver Island, 12% are in the South Interior, and 8% are in the Northern Region. With regard to residential sales, 53% occur in the Lower Mainland, 26% on Vancouver Island, 13% in the South Interior and 9% in the Northern Region.

6.2. Forecast Summary

Of the three major customer classes, apart from short-term weather impacts, the residential sector is the most stable in terms of demand variability. Sales to the residential sector are driven by two main factors – accounts and use per account. Growth in the number of residential accounts has been 1.5 percent per annum over the last 10 years. The annual growth rate in the number of accounts is expected to remain at 1.5 percent over the next 21 years. Growth in accounts is expected be strong the near and middle of the forecast period due to the significant investment expected to take place in the province.

Historical use per account reflects several factors such as the recent lingering recession, modifications to building standards, and changes in appliance efficiency and BC Hydro's DSM efforts. The forecast in use per account is expected to grow (before rate impacts and adjustments) on an average annual basis of 0.2 percent over the 21-year forecast period.

The residential load forecast is shown in Table 6.1, including a breakdown by the four main regions. The average annual growth in residential sales over the entire forecast period is expected to be about 446 GWh/year, including rate impacts and the adjustments for electric vehicles and the Load Forecast/DSM overlap for codes and standards

6.3. Residential Forecast Comparison

Residential sales in the 2011 Forecast are projected to be lower than the 2010 Forecast over the entire forecast period (see Figure 6.1). Before DSM with rate impacts the decrease in the residential sales forecast is 492 GWh (-2.7%) in F2012, 575 GWh (-2.8%) in F2016, 358 GWh (-1.6%) in F2022 and 161 GWh (-0.6%) in F2031. The key variable that accounts for the lower residential sales is the ending number of accounts forecast.

The ending number of accounts for F2011 was 1,654,079 which is 8,646 accounts (or 0.5%) below the level assumed in the 2010 Forecast. The lower starting point for the number of accounts combined with lower projections for housing starts are the main reasons driving the lower accounts forecast in the 2011 Forecast.

In the 2010 Forecast, the 5, 11, and 21-year growth rates for number of accounts were 2.0%, 1.9%, and 1.7% respectively. In the 2011 Forecast, the growth rates for number of accounts are 1.6%, 1.7% and 1.5%, respectively.

Figure 6.2 below illustrates the residential accounts forecast for the 2011 Forecast compared to the 2010 Forecast.

Figure 6.1. Comparison of Residential Sales before DSM and with Rate Impacts

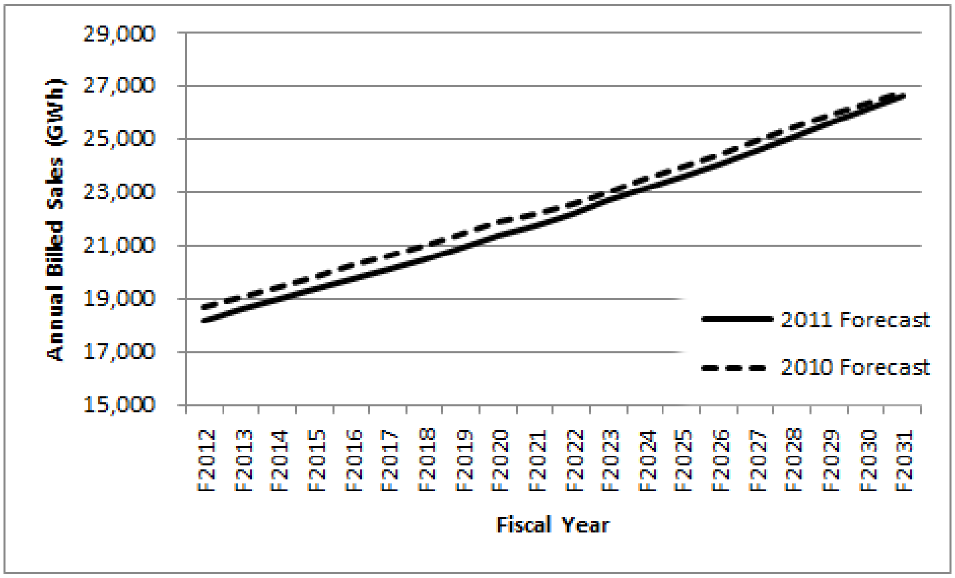
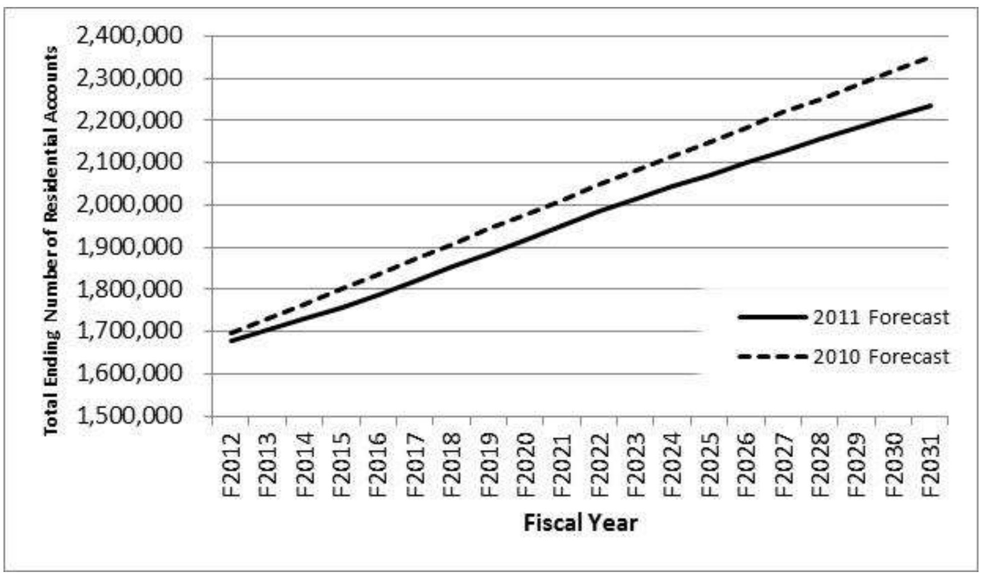


Figure 6.2. Comparison of Forecasts of Number of Residential Accounts



6.4. Key Issues

Over the longer term, the trend towards a slow growth in usage per residential account is not expected to change significantly because of the offsetting effects of the following factors:

- Increased electric space heating market share is expected to be offset by smaller housing units. Due to limited availability of land for residential development, the trend in metropolitan centres is expected to be towards denser housing. Since row houses and apartments are more likely to be built with electric heat compared to 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 generally have a smaller floor area than detached 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 the improvements in building standards and by the availability of natural gas on Vancouver Island.

- Manufacturers throughout Canada and the U.S. 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, the new models of these appliances tend to be larger and include more features than models currently in use. Therefore, some of the reduction in electricity use resulting from improvements in electricity efficiency will be offset by increases in appliance size and features.
- The projected decrease in the number of people per household tends to reduce electricity use per account. However, this reduction is expected to be offset by an increase in the penetration level of small appliances. Increases in electricity use are also projected to result from lifestyle changes and technological improvements, which 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 use rates will be offset by the factors working to decrease use rates.

6.5. Forecast Methodology

The forecast for residential sales is calculated as the product of the forecast number of accounts times the forecast use per account.

To develop the overall residential sales forecast, BC Hydro’s total service area was divided into four customer service regions – Lower Mainland, Vancouver Island, South Interior and Northern Region. For each region, a third party housing stock forecast was prepared based on the housing starts forecast in the region.

The 2011 residential load forecast was prepared using the Statistically Adjusted End-Use (SAE) model. Refer to Appendix 1.1 for further details on the residential sales methodology and drivers of the SAE model.

6.6. Risks and Uncertainties

Uncertainty in the residential sales forecast is due to uncertainty in three factors: forecast of number of accounts, forecast of use per account, and weather.

(a) Number of Accounts: In the short term, an error in the forecast for account growth would not result in a significant error in the forecast for total number of accounts. This is because account growth is on average 1.5% per year, so in the first year, an error of 1% in the forecast for account growth would result in an error of about 0.015% to the forecast for total number of accounts. However, in the long term, there is increased risk due to the cumulative effect of errors in the forecast for account growth.

(b) Use per Account: Most of the risk in the residential forecast is due to the forecast for use per account for the following reasons:

   i. Unlike the forecast of account growth, an error of 1% in the forecast for use per account in any year would contribute to a direct error of 1% to the forecast for residential sales for that year.

   ii. The forecast for use per account is the net result of many conflicting forces.

   Some of the forces working to increase use rate are:

   - increases in home sizes

- natural gas prices increasing faster than electricity prices
- increases in electric space heating share
- increases in real disposable income
- increases in saturation levels for appliances

Some of the forces working to decrease use rate are:

- increases in heating system efficiencies
- electricity prices increasing faster than natural gas prices
- new dwellings being built with higher insulation standards
- heat omissions from additional appliances reducing electric heating load
- increased use of programmable thermostats
- decreases in household sizes

Although all these positive and negative forces were recognized when the forecast for use rate was developed, there is uncertainty inherent in the forecasts for all these forces.

(c) Weather: In the short term, weather is highly variable. Therefore, in any one year, there is a risk that weather may have a significant impact on residential sales. For example, the El Nino event of F1998 is estimated to have reduced residential sales by about 4%. Since average weather is expected to be close to the rolling 10-year normal values used in the 2011 Forecast, weather is not viewed as being a high risk to the long-term forecast for residential sales.

Table 6.1. Residential Sales before DSM and with Rate Impacts

Fiscal Year	Residential Sales (GWh)				
	Lower Mainland	Vancouver Island	South Interior	Northern Region	Total Residential
Actual					
F2006	8,637	4,251	1,856	1,498	16,241
F2007	8,879	4,426	1,975	1,574	16,853
F2008	9,122	4,631	2,057	1,652	17,462
F2009	9,255	4,730	2,153	1,675	17,813
F2010	9,241	4,553	2,179	1,677	17,650
F2011	9,404	4,676	2,296	1,522	17,898
Forecast					
F2012	9,546	4,712	2,375	1,566	18,199
F2013	9,837	4,749	2,427	1,638	18,652
F2014	10,064	4,795	2,470	1,706	19,035
F2015	10,265	4,821	2,503	1,763	19,352
F2016	10,501	4,856	2,540	1,813	19,711
F2017	10,750	4,901	2,575	1,862	20,089
F2018	11,020	4,953	2,610	1,911	20,495
F2019	11,304	5,013	2,643	1,963	20,923
F2020	11,608	5,085	2,677	2,001	21,371
F2021	11,890	5,157	2,702	2,018	21,766
F2022	12,209	5,247	2,735	2,028	22,218
F2023	12,541	5,342	2,773	2,035	22,690
F2024	12,884	5,435	2,816	2,045	23,179
F2025	13,192	5,514	2,855	2,054	23,615
F2026	13,521	5,590	2,901	2,069	24,080
F2027	13,866	5,661	2,951	2,087	24,565
F2028	14,251	5,735	3,010	2,109	25,105
F2029	14,608	5,798	3,059	2,131	25,596
F2030	14,979	5,859	3,110	2,155	26,103
F2031	15,354	5,921	3,158	2,180	26,613
F2032	15,751	5,988	3,209	2,202	27,150
Growth Rates					
5 years: F2006 to F2011	1.7%	1.9%	4.3%	0.3%	2.0%
5 years: F2011 to F2016	2.2%	0.8%	2.0%	3.6%	1.9%
11 years: F2011 to F2022	2.4%	1.1%	1.6%	2.6%	2.0%
21 years: F2011 to F2032	2.5%	1.2%	1.6%	1.8%	2.0%

7 Commercial Forecast

7.1. Sector Description

The commercial sector currently comprises about 31 percent of BC Hydro's total annual sales. The commercial sector consists of distribution voltage sales (below 60 kV) and transmission voltage sales (above 60 kV). Also included within the commercial sector are street lighting, irrigation and BC Hydro Own Use, which is electricity for BC Hydro's buildings and facilities.

Within the commercial distribution area (93% of commercial sales), there are currently two major demand levels: (i) General Under 35 kW, which includes small offices, small retail stores, restaurants, and motels, and (ii) General Over 35 kW, which includes large offices, large retail stores, universities, hospitals and hotels.

The commercial transmission area (7% of commercial sales) includes universities, major ports and oil and gas pipelines.

7.2. Forecast Summary

Table 7.1 provides a summary of the historical and forecast sales before DSM and with rate impacts[8].

Electricity consumption in the commercial sector can vary considerably from year to year reflecting the level of activity in the service sector of B.C.'s economy. For example, between F2009 and F2010 sales decreased by 54 GWh or 0.3 percent, while total commercial sales increased by 265 GWh or 1.7 percent between F2010 and F2011. The annual average growth rate for commercial sales forecast over the next 5, 11 and 21 years (before DSM with rate impacts) to be 2.3 percent, 2.1 percent and 2.0 percent, respectively. Commercial distribution which is largest portion of total commercial sales is expected to grow on average by about 340 GWh per annum.

7.3. Commercial Forecast Comparison

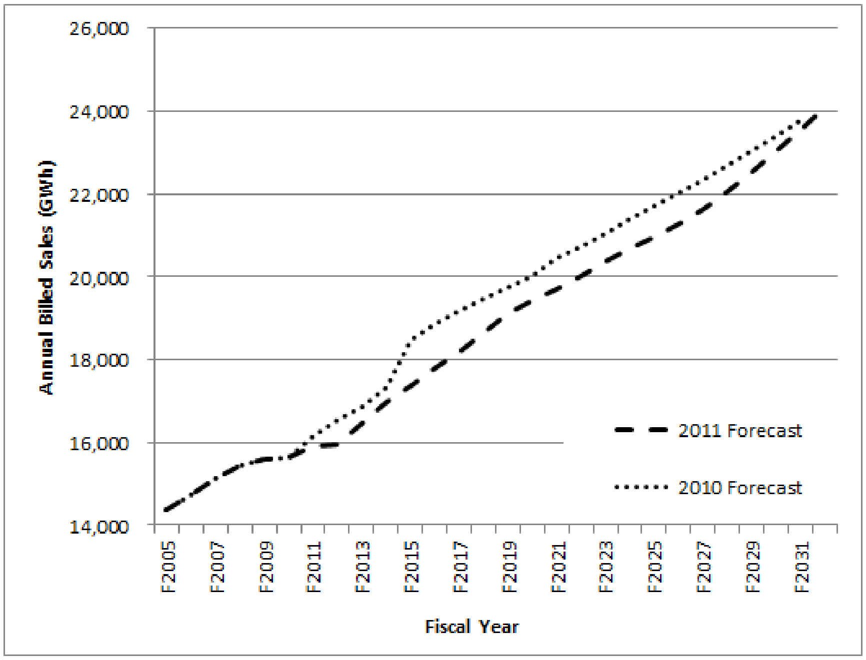
Figure 7.1 shows the 2011 Forecast of total commercial sales before DSM with rate impacts. Compared to the 2010 Forecast, the new total commercial sales forecast is lower by 585 GWh (-3.5%) in F2012, 1,059 GWh (-5.6%) in F2016, 698 (-3.4%) in F2022 and 218 GWh (-0.9%) in F2031.

Commercial distribution general sales, in the short and medium term, are very close to last year's forecast. Over the long term, the current commercial distribution forecast is higher than the 2010 Forecast due to revised assumptions for average stock efficiency and other economic drivers such as retail sales, employment and commercial GDP.

Commercial transmission sales are lower than in the 2010 Forecast. The reduced forecast for transmission customers stems from lower load expectations for larger universities, commercial bulk terminals and pipelines. The forecast for commercial oil and gas loads are further discussed in Appendix 3.1.

[8] Commercial general distribution sales as shown in Table 7.1 include the impact of EV and double counting adjustments for codes and standards.

Figure 7.1 Comparison of Commercial Sales Forecast before DSM with Rate Impacts



7.4. Key Issues

This section discusses the commercial sales growth projections for each of BC Hydro's four main service regions. Given that the health of the economy and business activity are key drivers of growth in commercial distribution sales, the comments below centre on the economic outlook for each region.

Lower Mainland

Approximately 65 percent of the sales in the commercial sector are located in the Lower Mainland. Commercial sales growth in this region over the next 5, 11 and 21 years is expected to be 2.5 per cent 2.5 percent and 2.4 percent.

After two relatively flat years, commercial economic output showed a strong increase of 3 percent in 2010. Major public and private projects underway or planned for the forecast horizon are expected to support strong growth in commercial activity. To support these projects, employment is expected to continue growing strongly in the near term and then moderating in the long term as the major projects wind down. Major projects directly impact employment in areas such as transportation, warehousing, utilities, financial and professional service industries and indirectly increase employment in the service sectors.

As new job seekers are attracted to the Lower Mainland, the population is expected to grow strongly, especially for the first half of the forecast horizon. The strong employment forecast will also result in buoyant retail sales, which increased by 3.8% in 2010 and is expected to continue to grow at above 2% per annum for the entire forecast period.

Vancouver Island

Vancouver Island makes up 16 percent of BC Hydro's total commercial sales. Commercial sales growth in this region is expected to be -0.1 percent, 0.2 percent and 0.5 percent, over the next 5, 11 and 21 years of the forecast, respectively.

During 2010, the Vancouver Island region experienced 2.9% growth in commercial output, which more than recovered the 2009 losses due to the slowdown in the public sector workforce and declines in tourism-related activity. However, moderate growth is expected in commercial output during the forecast horizon, mainly supported by jobs in the utilities sector, health care, education and government services.

After increasing by 2% in 2010, employment growth is expected to be modest, staying at or below 1% throughout the forecast period. Employment growth is expected in high wage industries, as such disposable income are expected to drive steady growth in retail sales.

South Interior

About 10 percent of BC Hydro's total commercial sales take place in the South Interior. Commercial sales growth in this region is expected to be 2.4 percent, 1.8 percent and 1.6 percent, over the next five, 11 and 21 years, respectively.

Commercial output grew by 4.6% in 2010 and is expected to grow between 1.7% and 2.7% throughout the forecast period. The growth is mainly supported by future mining and utility projects, especially in the near term.

Similarly, employment is expected to grow strongly in the near term, growing by 2.1 to 2.3% in the short term. However, employment growth is expected to slow down between 2015 and 2023, and decrease to 0.5% per annum for the rest of the forecast period. Retail sales will track employment growth but will generally outpace employment, since most new jobs are in high-paying industries such as mining, utilities, health care and education.

Northern Region

The Northern Region makes up 9 percent of the BC Hydro's total commercial sales. Commercial sales growth in this region is expected to be 5.3 percent, 3.0 percent and 1.5 percent, over the next five, 11 and 21 years, respectively.

Industrial output is the main driver of economic growth in the Northern Region. Economic conditions in the region's industrial base influence migration decisions to the region and drive employment growth, thus influencing income and services sector output growth.

Employment, output and population growth are expected to be strong until 2018, supported by major projects in natural gas, transportation (pipelines), mining, and power generation. Thereafter, employment and population growth is reduced and commercial sales stabilizing near the end of the forecast period. Retail sales will follow a similar trend, but will outpace employment because of the creation of higher-paying jobs.

7.5. Forecast Methodology

The main determinant of the commercial electricity sales forecast is the level of future economic activity in the province. This includes economic drivers such as retail sales, employment and commercial output. These economic variables are combined in the BC Hydro's SAE models that are used to develop the commercial distribution sales forecast for each of BC Hydro's four major service regions. The methodology for the commercial distribution sales forecast is described in Appendix 1.1.

Commercial transmission customer forecasts are developed on individual account basis, which is similar to the approach used for developing individual forecasts for industrial customers. Further information on the inputs and methodology used to develop the load forecast for large transmission customers is found in Chapter 8.

At an aggregate level, consumption in the commercial sector is tied closely with economic activity in the province. The stronger the economy, the more services are needed and the greater the electricity consumption of the commercial sector. Regional economic drivers such as retail sales, employment, and commercial output are good indicators of electricity consumption in the sector. At a more detailed level, the consumption in the commercial sector is related to the growth in the number of facilities and the amount of energy required to service various end-uses.

7.6. Risk and Uncertainties

Commercial sales models are dependent on the outcome of the regional economic drivers. The regional economic forecasts are provided by Stokes Economic Consulting. In the SAE model, heating degree days and cooling degree days are used to calculate the heating and cooling variables. Total commercial sales are not as sensitive to weather as compared to residential sales. Since the increase in the forecast commercial sales is attributed to larger commercial projects including pipelines and storage facilities, there is some uncertainty regarding the completion of large individual projects and their need for electrical service.

Factors Leading to Lower than Forecast Commercial Sales:

- A change in the economic conditions as commercial sales tends to follow the major indicators of the economy;
- The pine beetle infestation will cause forestry employment to decline in the long term;
- Improved equipment efficiency across the end uses; and
- The aging provincial population will decrease future employment growth.

Factors Leading to Higher than Forecast Commercial Sales:

- A robust economic recovery and tourism activity that would create additional demands for commercial services;
- Low interest rates encourage consumer spending; and
- Substantially warmer summers (increasing air conditioning loads) or colder winters (increasing heating loads) relative to historical patterns.

Table 7.1. Commercial Sales before DSM with Rate Impacts

Fiscal Year	Commercial Sales (GWh)			
	Irrigation, Street Lights and BC Hydro Own Use	Commercial General Distribution	Commercial Transmission	Total Commercial Sales[1]
Actual				
F2006	380	13,630	710	14,721
F2007	380	13,991	734	15,105
F2008	379	14,230	831	15,439
F2009	368	14,398	811	15,577
F2010	371	14,235	1,025	15,631
F2011	359	14,475	1,062	15,896
Forecast				
F2012	363	14,551	1,051	15,964
F2013	366	14,892	1,203	16,460
F2014	368	15,191	1,398	16,957
F2015	369	15,471	1,550	17,390
F2016	371	15,792	1,648	17,811
F2017	372	16,107	1,716	18,196
F2018	374	16,432	1,814	18,620
F2019	376	16,782	1,930	19,087
F2020	377	17,114	1,942	19,433
F2021	379	17,378	1,957	19,714
F2022	381	17,685	1,967	20,034
F2023	384	17,991	1,978	20,353
F2024	386	18,296	1,990	20,672
F2025	388	18,557	1,998	20,944
F2026	391	18,869	2,007	21,267
F2027	393	19,225	2,016	21,635
F2028	395	19,664	2,025	22,084
F2029	398	20,101	2,035	22,535
F2030	400	20,590	2,046	23,036
F2031	402	21,085	2,056	23,544
F2032	405	21,598	2,066	24,069
Growth Rates				
5 years*: F2006 to F2011	-1.2%	1.2%	8.4%	1.6%
5 years: F2011 to F2016	0.7%	1.8%	9.2%	2.3%
11 years: F2011 to F2022	0.6%	1.8%	5.8%	2.2%
21 years: F2011 to F2032	0.6%	1.9%	3.2%	2.0%

* Historical growth rates are not weather normalized. Forecast is prepared based on normal weather.

1. Total commercial sales are the sum of Irrigation, Street Lights and BC Hydro Own Use plus Commercial Distribution and Commercial Transmission.

8 Industrial Forecast

8.1 Sector Description

The industrial sector currently comprises about 31 percent of BC Hydro's total annual sales. It is organized into four main sub-sectors: forestry, mining, oil and gas and other. Industrial customers are involved in extracting, processing and manufacturing resource based commodities which are destined for exports.

The industrial sector is also organized by voltage service (transmission vs. distribution). Approximately 80% of the total industrial sales are served at transmission voltages (above 60 kV) with the remaining 20% served at distribution voltages (below 60 kV).

New LNG facilities, which are categorized as industrial sector load, potentially represent the biggest additional loads on BC Hydro's system.

The Initial LNG Load is expected to require about 5,000 GWh/year of energy for refrigeration and associated pipeline compression load. It is a very large load that would have a profound impact on BC Hydro and its planning processes.

More information on the potential new LNG facilities and pipeline loads included in the 2011 Load Forecast can be found in Appendix 3.2.

8.2 Forecast Summary

Total industrial sales forecast before DSM and rate impacts are shown in Table 8.1 and Table 8.2. Table 8.1 shows a consolidated projection of industrial sales broken down by industry sub-sectors. Table 8.2 shows total industrial sales broken down between transmission and distribution voltage customers.

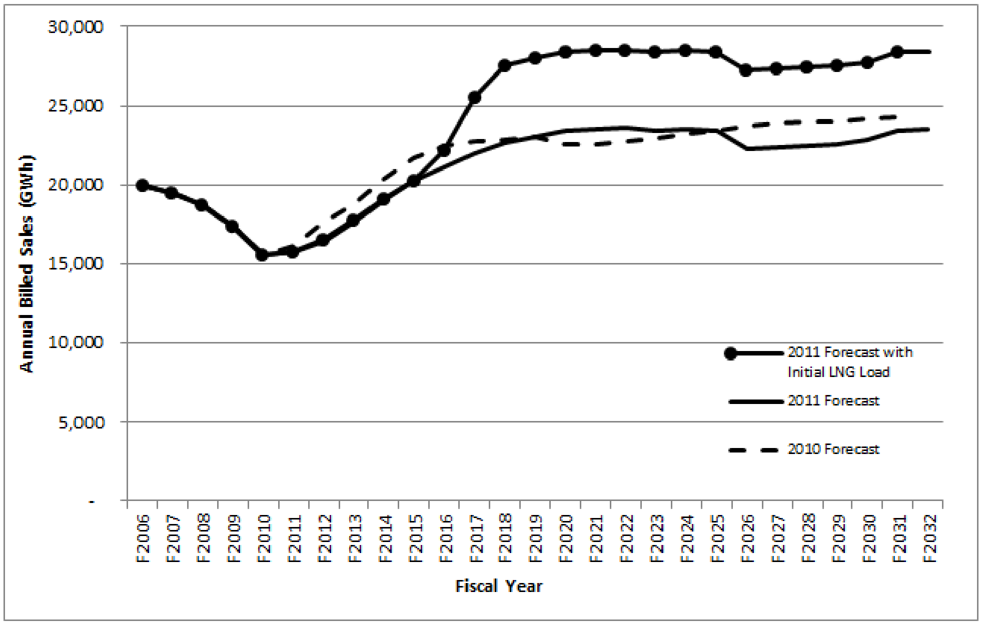
Over the past five years, total industrial sales declined by about 20 percent. This was primarily due to a decline in forestry sales due to structural changes and permanent closures of pulp and paper mills. Total industrial sales in F2012 are expected to increase by 686 GWh or 4.3 percent relative to F2011, with growth in most of the sub-sectors.

The five, 11 and 21-year year growth projection of total industrial sales before Initial LNG Load, before DSM and rate impacts is 6.0 percent, 3.7 percent and 1.9 percent, respectively. Looking forward, BC's industrial customers are expected to have a strong global position due to the quality of the resource base, the demand for B.C.'s natural resources and advanced infrastructure to supply industrial products to market.

8.3 Industrial Forecast Comparison

Figure 8.1 compares the 2011 Forecast to the 2010 Forecast (before DSM and rate impacts).

Figure 8.1. Comparison of Industrial Sales Forecast before DSM and Rate Impacts (Excluding and Including Initial LNG Load)



During F2012 to F2019, the 2011 Forecast without Initial LNG Load is expected to be below the 2010 Forecast due to lower sales projections for the forestry sector. Between F2020 and F2024, industrial sales are forecast to be relatively higher due to the extension of activities for existing mines with previously announced shutdown dates. After F2024, the 2011 Forecast once again falls below last year's projection due to weaker pulp and paper sales.

8.4 Key Issues and Sector Outlook

The following sections describe the outlook, drivers and risk factors for the major industrial sub-sectors. Unless otherwise stated, the comparison between the 2010 Forecast and the 2011 Forecast is based on sales by transmission customers only.

8.4.1 Forestry

The forestry sector accounts for about 60 percent of industrial sales. Forestry is categorized into three sub-sectors: pulp and paper, wood products and chemicals. Although generalizations can be made across the forestry sector (for instance, the impact of the pine beetle infestation and the recent recession), each sub-sector has different sales history, drivers and market characteristics.

Forestry sales have changed significantly over the past number of years. It is expected that the demand for forestry sector goods will continue to recover from the 2008-2009 recession. During the past four years, forestry sales declined by about 30 percent, largely due to the pulp and paper and wood product sub-sectors which both experienced shutdowns. In F2012, forestry sales are forecast to increase by seven percent relative to F2011 due to growth in all three forestry sub-sectors.

For the five years ending in F2016, projected sales initially rise before falling back to F2011 levels. The decline is attributable to further restructuring measures in the pulp and paper sub-sector and increasing constraints in the wood products sub-sector due to the continuing impact of the pine beetle Infestation. During the F2016-F2021 period, sales remain relatively unchanged with moderate growth in pulp and paper sales being offset by anticipated declines in wood products sales.

For the latter 10 years of the forecast period, forestry sales are relatively flat before increasing near the end of the forecast horizon. See details in the Overview following. Pulp and paper sales are forecast to increase based on the expectation of successful industry restructuring. However, wood products sales remain unchanged as the pine beetle infestation continues to hamper production levels.

Compared with the 2010 Forecast, the 2011 Forecast is approximately 900 GWh lower at the end of the forecast period. This is primarily due to the pulp and paper sub-sector where production expectations for certain product grades have been reduced relative to the 2010 Forecast.

8.4.1.1 Pulp and Paper Overview

Transmission pulp and paper sales represent 62 percent of forestry sector sales and 38 percent of industrial sales. Pulp and paper sales are concentrated in 19 mills located primarily in the south-western and north-eastern parts of B.C. These mills produce and export a wide variety of products including newsprint, coated and uncoated groundwood paper, unbleached kraft (UBK) pulp, bleached chemical pulp, thermo-mechanical pulp (TMP) and marked bleached thermo-mechanical pulp (CTMP). Softwood is predominantly used by mills in the Prince George, Quesnel, South Interior and Vancouver Island regions. Hardwood is used by northern mills located in the Chetwynd area. Vancouver Island uses softwood to produce TMP and CTMP.

The main drivers for this sub-sector are pulp and paper market prices, the U.S. economy and increasingly, the global economy.

Pulp and Paper Outlook

Over the past four years, transmission pulp and paper sales declined by about 30 percent largely due to pulp and paper mill and line closures. The factors contributing this large decrease include: aging equipment, declining fibre availability (due to pine beetle infestation), rising prices of recycled feedstock (due to Chinese demand), strong competition from mills in South America, displacement of newspaper by digital media and increased targeting of electronic media by advertisers.

F2010 was particularly hard for pulp and paper producers as the 2008-09 recession caused prices and demand to drop. As a consequence, several medium-to-large pulp and paper producers announced permanent closures in 2010, including Catalyst (formerly BC Hydro's largest customer) which closed its Elk Falls mill.

In F2012, sales are forecast to increase slightly over prior year levels with pulp and paper prices and production expected to remain at healthy levels. For the first 10 years of the 2011 Forecast, transmission pulp and paper sales are projected to decline by over 500 GWh or 8 percent. Further mill and line closures are expected to occur as the industry continues to restructure in order to become more competitive.

In the latter half of the forecast period, sales are projected to grow by about 600 GWh. During this period, further mill and line closures are expected but there will also be mill and line expansions into areas that better leverage the operational and fibre environment in which B.C. pulp and paper mills operate.

Compared to the 2010 Forecast, the 2011 Forecast for pulp and paper is lower by roughly 500 GWh in the first 10 years and lower by over 1,000 GWh in F2032. These reductions are primary the result of lowered production expectations for certain product grades.

Pulp and Paper Drivers and Risk

Drivers:

- North American paper demand for advertising;

- Growing demand for paper products and market pulp by China and other developing economies because of increased needs for packaging materials and tighter markets for fibre (positive factors for B.C.);
- Global demand for B.C.'s attractive wood fibre which adds strength to recycled papers and a growing number of other applications and products;
- Growing demand for B.C.'s environmentally-friendly pulp and paper (i.e. produced with renewable fuel);
- Ability of B.C. mills to transition away from kraft pulp and newsprint to higher value products;
- Incentive programs for increased electricity self-generation at kraft mills; and
- B.C. having one of the lowest industrial electricity costs in the world.

Risk Factors:

- Economic swings in the U.S.;
- Fibre shortage due to pine beetle infestation. This will reduce fibre supply for B.C. pulp mills which use residual chips from lumber and whole log chipping;
- Competition for fibre supply from bio-fuel and pellet operations;
- Ongoing decline in the North American newsprint market, where both shipments and advertising expenditures have been progressively declining over the last 10 years;
- Displacement of B.C. softwood with hardwood pulp by low-cost competitive mills which continue to be built in the Southern Hemisphere;
- Risk of major equipment failure as some assets near end-of-life, with some mills being forced to close due to a lack of cash flow to fix or replace such capital-intensive assets;
- Long-term Chinese demand for pulp and paper; and
- Long-term global demand for tissue.

8.4.1.2 Wood Products Overview

Wood products represent about 23 percent of forestry sector sales. BC Hydro services more than 100 wood products mills located in every major region of B.C., particularly the North Coast, Central Interior and Southern Interior which contain 75 percent of the mills. These facilities produce dimensional and structural lumber, oriented strand board (OSB), medium density fiberboard, plywood, fuel pellets and other specialty products.

The primary drivers for wood products demand are housing starts in the U.S., China and Japan. B.C.'s share of the U.S. lumber market is greater than all other non-U.S. producers combined. Furthermore, B.C. could soon displace Russia as the dominant lumber supplier to the Chinese market.

The B.C. Interior has some of the lowest cost producers of lumber in the world. However, wood product sector sales are expected to drop below historical and current levels due to Ministry of Forestry measures dealing with the pine beetle infestation. It is anticipated that forest management practices will be imposed (i.e., limiting the annual allowable cut) such that lumber production will be dramatically reduced. A sustainable level of logging and annual allowable cut is expected to be reached around 2024. Thereafter, wood products sales are expected to remain flat for the duration of the forecast period.

Wood Products Outlook

The 2008-09 recession had a devastating effect on the wood products sub-sector. Over the last four years, sales fell by 23 percent due primarily to depressed U.S. housing starts.

In F2012, wood products sales are forecast to increase by 7 percent largely due to growing lumber exports to China.

In the near term, sales are expected to increase moderately due to growing demand from China, a recovery in U.S. housing starts and construction activity in post-tsunami Japan. During the five years ending in F2022, B.C. wood products sales are expected to progressively decline. It is expected that demand for B.C. wood products will exceed the industry's ability to supply due to constraints caused by the Mountain Pine Beetle. For beetle-killed trees, the amount of useable lumber diminishes over time due to deterioration.

Over the last 10 years of the forecast period, wood product sales are projected to remain flat, although below historical levels, and below market demand. BC Hydro expects B.C. forest management practices to successfully achieve a sustainable annual cut level which in turn will stabilize lumber production.

Overall, the 2011 Forecast is only moderately higher than the 2010 Forecast, largely due to assumptions with respect to the severity of the pine beetle infestation on the wood products sub-sector, which are reflected in both forecast vintages.

Wood Products Drivers and Risk

Drivers:

- U.S. housing starts (currently are one-third of normal levels);
- Chinese demand for roof trusses and framing for houses and small apartments;
- Japanese housing starts (demand for hemlock and SPF); and
- Demand from other areas in the world such as Korea, India, Taiwan, Hong Kong, Singapore and the Middle East.

Risk Factors:

- Recovery of U.S. housing starts;
- A softwood lumber dispute with the U.S.;
- Harvest life of trees killed by the Mountain Pine Beetle;
- Medium to long run severity of pine beetle infestation;
- Higher harvesting costs for B.C. coastal sawmills (caused by steep terrain, outdated equipment and relatively high labour costs);
- Ability of industry in B.C. Interior to transition towards processing higher volumes of beetle-killed timber; and
- Ability of B.C.-based OSB producers to continue to improve products for markets.

8.4.1.3 Chemicals Overview

Chemicals represent about 15 percent of forestry sector sales. Sales are primarily to five customers who produce bleaching agents for the pulp and paper industry, as well as cleaning agents for the oil and gas industry and for water purification. Chemical sales are strongly correlated to the health of the pulp and paper industry, particularly the global industry given that much of the product is destined for export. Since chemical companies use electrolysis to producer their bleaching agents, electricity forms a large part of their operating costs.

Chemicals Outlook

Over the past four years, sales in this sector have remained relatively flat with modest dips that arose due to closures of pulp and paper mills and lines in B.C. In F2011, sales were particularly low due to an extended downtime at a large customer facility experiencing a complete plant makeover. In F2012, sales are forecast to increase by 19 percent over depressed F2011 levels as sales of bleaching and cleaning agents (to the pulp and paper and oil and gas industries) are expected to increase and customer downtime for facility change-over is not expected to continue.

In the near term, chemical sales are expected to slowly increase as some facilities are expanded to meet growing demand for bleaching and cleaning agents, some of which is driven by exports. In the medium and long term, sales are projected to only modestly grow due to weak demand in the B.C. pulp and paper sector, but otherwise stimulated by growing demand for cleaning agents (for the oil and gas industry) and water purification agents (for municipalities). Much of this demand growth in the latter half of the forecast period will be export-based.

Chemical Drivers and Risk

Drivers:

- Pulp and paper demand;
- Global economy; and
- Oil and gas activity.

Risk Factors:

- Electricity rate increases;
- Closure of B.C. pulp mills; and
- Capability of some chemical customers to transition into producing the type of bleaching agents that can be exported outside of B.C.

8.4.1.4 Forestry Methodology

The 2011 forecast for the forestry sector was developed by initially assessing last year's forecast. BC Hydro determined that updated information was required for several areas including: (i) a forecast of lumber exports to China (ii) the expected impact of the pine beetle infestation; and (iii) customer mill production To obtain the necessary information, BC Hydro retained a consultant with relevant forestry expertise.

To assist the consulting team, BC Hydro provided the consultants a 30-year GDP forecast for several countries that commonly purchase B.C. forestry products. The consulting team produced mill production forecasts for all B.C. mills and for various product lines. BC Hydro incorporated these production forecasts into its load forecasting model to create a sector forecast. The forestry forecast also considered issues such as customers with onsite generation, electricity purchase agreements, historical consumption and electricity consumption intensities, as well as input from BC Hydro's Key Account Managers.

BC Hydro developed the forestry sector forecast by multiplying facility production forecasts by the of electricity intensity forecast.

8.4.2 Mining

The mining sector accounts for about 17 percent of total industrial sales. It is categorized into two sub-sectors: metal mines and coal mines. For mining customers, electricity is mostly used for ore extraction, crushing and processing.

In the short run, mining sales are not highly sensitive to economic drivers and mineral price movements since existing mines tend to produce continuously through commodity price cycles. In the medium to long term, mining expansions (or contractions), start-ups (or closures) and new project advancements (or deferrals) are sensitive to economic conditions and mineral prices.

The Asia-Pacific region is important for the health of mining in B.C. because more than two-thirds of mining exports are shipped to Japan, China and South Korea. The future outlook for mining is also shaped by mineral exploration, which in turn is influenced by provincial policy. The recovery in metal and coal prices following the 2008-09 recession, as well as steady demand growth expected from China and India have spurred recent mining activity in B.C. These favourable developments have been reflected in the tripling of exploration expenditures since 2009 (see Figure 8.2) and the positive long-term outlook for existing and potential new operations.

Overall, the province of B.C. enjoys a competitive advantage in mining due to its proven mineral, rail, road and port infrastructure, skilled workforce and competitive tax structure and incentives. The mining industry prominently featured in the 2011 BC Job Plan wherein the Premier announced the commitment to eight new mines and the expansion of another nine operating mines by 2015. Furthermore, B.C. is the first province in Canada to share direct provincial mineral tax revenue generated from new mines or mine expansions with First Nations.

The B.C. mining industry has become increasingly attractive for foreign investment. Notable investments over the past couple of years have included Mitsubishi's $250 million cash injection in Copper Mountain's Similco mine and the 25% acquisition of the Gibraltar mine by a consortium of Japanese investors led by the Sojitz Corporation.

Mining sales in F2012 are forecast to be slightly lower than in the prior year due to revised timing for mine start-ups and expansions. However, sales are projected to almost double by F2016 due to new projects coming online and major upgrades to several existing operations. Mining activity is expected to peak around F2022 when total sector sales are forecast to exceed 6,700 GWh. In the long run, mining sales are expected to grow at a moderate rate with B.C. continuing to provide mining products to the world.

Figure 8.2 Mineral Exploration in B.C.

Calendar Year (January - December)	Exploration Expenditures ($ in millions)
2011	463
2010	322
2009	154
2008	367
2007	416
2006	265
2005	220
2004	130
2003	52
2002	40
2001	32
2000	30
1999	25
1998	38
1997	80
1996	105
1995	78
1994	98
1993	66
1992	72

Source: BC Ministry of Energy and Mines

8.4.2.1 Metal Mines Overview

Metal mines account for about 80 percent of total mining sector sales. Most of the electricity is used to for producing various grades of copper, molybdenum and gold – commodities which are primarily produced for export.

In the long term, electricity sales to mines are tied to price expectations for copper, molybdenum and gold. The prices of these commodities are influenced by global demand and supply and the state of the global economies. In the short term, electricity sales to metal mines are relatively independent of commodity price fluctuations because these mines are predominantly fixed-cost operations which typically need to run continuously. Mining sales are not overly dependent on domestic economic activity but are more correlated to the global economy given that about 80 percent of B.C. metals production is exported.

Since 2009, mining actively in B.C. has benefited from strong copper and gold prices. In recent years, there has been increased mineral exploration activity in B.C. The 2011 Forecast assumes that that several new B.C. mining projects will proceed. British Columbia is viewed as an attractive environment for global mining investment. As the global economic recovery continues, the world's demand for minerals is expected to grow.

Metal Mines Outlook

Sales to metal mining customers in F2012 are expected to decrease given that the shutdown of medium-sized mine during 2011 is only partially offset by the restart of similar sized operations. In the short term, several new projects have deferred start dates lowering the forecast compared to the 2010 Forecast.

In the medium to long term, metal mine sales are expected to rise significantly. By F2020, sales are expected to increase by over 3,500 GWh as new mines come online and several existing mines ramp up production. The demand for copper and molybdenum is expected to be driven by high demand from both Asia and recovering Western economies. In addition, sales growth is driven by development of the Northwest Transmission Line (NTL) which will supply electricity to new mines in that region of B.C.

Compared to the 2010 Forecast, this year's metal mining sales forecast is slightly lower in short term, increases by about 1,600 GWh in the medium term and then converges to the same level by 2026. The higher medium-term forecast results from the extension of activities for two large existing mines that had previously announced shutdown dates.

Metal Mine Drivers and Risk

Drivers:

- Copper, gold and molybdenum prices which in turn are driven by economic activity;
- Industry perception of the resource friendliness of the B.C. government and its present and future tax regime; and
- Level of supporting infrastructure (ports, roads, power and proximity to communities), and the potential for future development.

Risk Factors:

- Future provincial and federal government actions that increase or decrease clarity of regulatory policy, conflict resolution measures, and tax efficiencies;
- Outcome of future Environmental Assessment applications, particularly with regard to First Nations issues; and
- Aging workforce and the looming wave of retirements over the next years.

8.4.2.2 Coal Mines Overview

Coal mines comprise about 20 percent of BC Hydro's consolidated mining sector sales. The coal is predominantly produced in southeastern B.C. with the larger coal mining customers in this region accounting for roughly 90 percent of total sales. Coal is also produced in the northeastern B.C., which currently has a small production share but is expected to grow. The ports of Metro Vancouver and Prince Rupert are the closest gateways to Asia from North America thereby facilitating coal exports from B.C.

Elk Valley Coal Partnership, which owns five mines in southeastern B.C., is the second biggest supplier of metallurgical coal in the world. Metallurgical coal is an export commodity which is sold worldwide to integrated steel mills for steel-making purposes.

In the long term, coal mining sales are tied to price expectations for coal, which is largely driven by metallurgical coal demand. Most of the coal mined in B.C. has historically been sold to Japan and South Korea, but China is emerging as a fast-growing market which accounts for 16% of B.C. coal exports. In its 2011 Medium-Term Coal Market report, the International Energy Agency states "Chinese domestic coal market is more than three times the entire international coal trade," and as such, "any imbalance between Chinese production and demand has the ability to have a large impact on global coal trade."

In the short term, sales are relatively independent of the movements in spot market coal prices since coal mines generally negotiate prices on a quarterly or annual basis. The state of the B.C. economy has little effect on coal sales but provincial regulatory and policy actions can have a significant impact.

Coal Mines Outlook

In the 2011 Forecast, short-term coal mining sales are expected to increase significantly due to expanded production from existing mines and the anticipated start-up of new mines in northeastern B.C. Global demand for metallurgical coal, particularly from China and India, is expected to be strong over this time period. Coal mining sales are forecast to peak around F2017 at levels which are 70-90 percent higher than sales in F2011.

Over the medium to long term, consolidated coal sales growth is projected to slow due to more moderate expectations of growth in the global economy and rail line and mine constraints in B.C.

Compared to the 2010 Forecast, the current forecast is higher in medium and long term. This is largely the result of improved expectations for several new coal mine projects.

Coal Mine Drivers and Risk

Drivers:

- Demand for steel in Japan, South Korea, China, the European Union and India; and
- Global economic outlook, particularly in Asia and the U.S.

Risk Factors:

- Expanded Australian coal production. Australia accounts for roughly two-thirds of the global metallurgical coal production;
- B.C. mining construction costs; and
- Future policies or regulations that could impact coal exploration or development.

8.4.2.3 Mining Methodology

To develop the 2011 forecast for coal mining, BC Hydro relied upon a consulting team with a proven record that annually publishes a B.C. mining report. To assist in the development of consultant's production forecast, BC Hydro provided a 30 year GDP forecast for major countries which the consultant used to base its economic outlook on.

BC Hydro received the mining production forecasts and metrics from the consultant. BC Hydro then used all available information and its own judgement to assign risk assessments to new mines.

8.4.2 Oil and Gas

Oil and gas loads exist in both the industrial and commercial sectors. The forecast outlook and drivers for the oil and gas sector are fully described in Appendix 3.1. In addition, Appendix 3.2 provides an overview of the unconventional shale gas sub-sector in northeastern B.C.

8.4.4. Other Industrials

As shown in Table 8.1, sales to other industrial customers account for about 17 percent of total industrial sales. Many of the customers in the other category produce goods for the B.C. market and thus their associated sales are relatively correlated with the growth in provincial economy.

8.4.1.1. Other Industrials Overview and Outlook

From F2006 to F2009, sales to other industrial customers were relatively flat but declined by about 7 percent in F2010-11 due to the economic downturn in the economy and a slowdown in cement company operations. Sales in F2012 are expected to rise by four percent due to the recovery in the provincial economy.

For the first five years of the forecast, sales are expected to grow by 2.3 percent per year largely due to the slow rebound in cement sales. For the medium to long term, annual sales growth slows down to roughly two percent given the expected slowdown in provincial and global economic growth.

Compared to the 2010 Forecast, sales to other industrial customers in the 2011 Forecast are slightly lower for each year of the forecast period. Towards the end of the 20-year forecast period, sales in the current forecast are below last year's forecast by less than one percent.

Other Sector Drivers and Risk

Drivers:

- Provincial economic growth; and
- Construction activity, which in turn affects the demand for cement producers.

Risk Factors:

- Economic slowdown or sectorial shifts in B.C. economy; and
- Increased environmental regulations which could affect the competitiveness of large cement producers.

Table 8.1 Consolidated Industrial Sales Forecast by Sector before DSM and Rate Impacts (excluding and including Initial LNG Load)

Fiscal Year	Industrial Sales (GWh)								
	Mining		Forestry						
	Metal Mines	Coal Mines	Wood	Pulp & Paper	Chemical	Oil & Gas	Other	Total Industrial Sales (excluding Initial LNG)	Total Industrial Sales (including Initial LNG)
Actual									
F2006	2,312	527	2,839	9,037	1,744	640	2,836	19,936	19,936
F2007	2,297	513	2,850	8,678	1,587	660	2,884	19,469	19,469
F2008	2,259	545	2,674	8,024	1,591	693	2,950	18,737	18,737
F2009	2,282	530	2,228	7,184	1,494	770	2,894	17,382	17,382
F2010	2,308	524	2,039	5,830	1,521	691	2,696	15,608	15,608
F2011	2,302	534	2,189	5,928	1,380	771	2,680	15,783	15,783
Forecast									
F2012	2,173	606	2,344	6,142	1,636	847	2,724	16,472	16,504
F2013	2,786	678	2,529	6,019	1,678	1,196	2,817	17,703	17,726
F2014	3,391	809	2,559	5,813	1,694	1,888	2,900	19,054	19,077
F2015	4,077	879	2,573	5,499	1,710	2,519	2,959	20,216	20,295
F2016	4,472	988	2,571	5,305	1,710	3,053	3,008	21,108	22,192
F2017	5,049	1,015	2,500	5,341	1,710	3,260	3,062	21,938	25,489
F2018	5,521	1,018	2,428	5,419	1,710	3,417	3,118	22,631	27,566
F2019	5,734	1,021	2,315	5,530	1,710	3,552	3,187	23,051	27,986
F2020	5,864	1,021	2,241	5,710	1,710	3,635	3,243	23,424	28,359
F2021	5,908	1,022	2,166	5,643	1,710	3,802	3,281	23,533	28,468
F2022	5,908	1,022	2,157	5,643	1,710	3,848	3,312	23,600	28,535
F2023	5,723	1,022	2,118	5,643	1,722	3,883	3,342	23,453	28,388
F2024	5,736	1,022	2,118	5,643	1,733	3,915	3,369	23,537	28,472
F2025	5,629	1,022	2,118	5,597	1,744	3,945	3,394	23,449	28,384
F2026	4,423	1,022	2,119	5,591	1,755	3,973	3,423	22,307	27,242
F2027	4,445	1,022	2,118	5,581	1,765	4,001	3,448	22,382	27,317
F2028	4,467	1,022	2,117	5,576	1,776	4,028	3,478	22,465	27,400
F2029	4,490	1,022	2,118	5,576	1,786	4,054	3,511	22,558	27,493
F2030	4,512	1,022	2,118	5,746	1,797	4,079	3,550	22,824	27,759
F2031	4,535	1,022	2,118	6,255	1,808	4,101	3,585	23,423	28,358
F2032	4,557	1,020	2,118	6,255	1,818	4,087	3,615	23,471	28,406
Growth Rates:									
5 years: F2006 to F2011	-0.1%	0.3%	-5.1%	-8.1%	-4.6%	3.8%	-1.1%	-4.6%	-4.6%
5 years: F2011 to F2016	14.2%	13.1%	3.3%	-2.2%	4.4%	31.7%	2.3%	6.0%	7.1%
11 years: F2011 to F2022	8.9%	6.1%	-0.1%	-0.4%	2.0%	15.7%	1.9%	3.7%	5.5%
11 years: F2011 to F2032	3.3%	3.1%	-0.2%	0.3%	1.3%	8.3%	1.4%	1.9%	2.8%

Table 8.2 Industrial Sales Forecast by Voltage Service before DSM and Rate Impacts (excluding and including Initial LNG Load)

Fiscal Year	Transmission Voltage Customers (GWh)							Distribution	Total Industrial Sales (excluding Initial LNG)	Total Industrial Sales (including Initial LNG)
	Mining		Forestry							
	Metal Mines	Coal Mines	Wood	Pulp & Paper	Chemical	Oil & Gas	Other	All Sectors		
Actual										
F2006	2,312	507	1,110	9,037	1,744	524	428	4,272	19,936	19,936
F2007	2,297	475	1,195	8,678	1,587	551	434	4,252	19,469	19,469
F2008	2,259	496	1,162	8,024	1,591	587	436	4,181	18,737	18,737
F2009	2,282	478	1,001	7,184	1,494	664	389	3,891	17,382	17,382
F2010	2,308	474	973	5,830	1,521	575	314	3,613	15,608	15,608
F2011	2,302	484	1,051	5,928	1,380	608	327	3,704	15,783	15,783
Forecast										
F2012	2,173	536	1,136	6,142	1,636	659	337	3,852	16,472	16,504
F2013	2,786	581	1,271	6,019	1,678	848	387	4,133	17,703	17,726
F2014	3,391	705	1,278	5,813	1,694	1,489	423	4,261	19,054	19,077
F2015	4,077	761	1,273	5,499	1,710	2,062	434	4,400	20,216	20,295
F2016	4,472	813	1,276	5,305	1,710	2,502	434	4,595	21,108	22,192
F2017	5,049	822	1,276	5,341	1,710	2,669	434	4,635	21,938	25,489
F2018	5,521	822	1,216	5,419	1,710	2,802	434	4,706	22,631	27,566
F2019	5,734	822	1,159	5,530	1,710	2,920	434	4,741	23,051	27,986
F2020	5,864	822	1,117	5,710	1,710	2,967	434	4,799	23,424	28,359
F2021	5,908	822	1,008	5,643	1,710	3,122	435	4,884	23,533	28,468
F2022	5,908	822	1,003	5,643	1,710	3,160	438	4,916	23,600	28,535
F2023	5,723	822	998	5,643	1,722	3,187	441	4,917	23,453	28,388
F2024	5,736	822	997	5,643	1,733	3,211	444	4,950	23,537	28,472
F2025	5,629	822	997	5,597	1,744	3,232	447	4,981	23,449	28,384
F2026	4,423	822	997	5,591	1,755	3,252	450	5,015	22,307	27,242
F2027	4,445	822	997	5,581	1,765	3,272	453	5,045	22,382	27,317
F2028	4,467	822	997	5,576	1,776	3,292	456	5,078	22,465	27,400
F2029	4,490	822	997	5,576	1,786	3,310	459	5,116	22,558	27,493
F2030	4,512	822	997	5,746	1,797	3,328	463	5,158	22,824	27,759
F2031	4,535	822	997	6,255	1,808	3,344	467	5,195	23,423	28,358
F2032	4,557	820	997	6,255	1,818	3,360	470	5,192	23,471	28,406
Growth Rates:										
5 years: F2006 to F2011	-0.1%	-0.9%	-1.1%	-8.1%	-4.6%	3.0%	-5.3%	-2.8%	-4.6%	-4.6%
5 years: F2011 to F2016	14.2%	10.9%	4.0%	-2.2%	4.4%	32.7%	5.8%	4.4%	6.0%	7.1%
11 years: F2011 to F2022	8.9%	4.9%	-0.4%	-0.4%	2.0%	16.2%	2.7%	2.6%	3.7%	5.5%
21 years: F2011 to F2032	3.3%	2.5%	-0.3%	0.3%	1.3%	8.5%	1.7%	1.6%	1.9%	2.8%

9 Non-Integrated Areas and Other Utilities Forecast

9.1 Non-Integrated Areas

The Non-Integrated Areas (NIA) includes the Purchase Area, Zone II and Fort Nelson. A number of small communities located in the northern and southern parts of B.C. that are not connected to BC Hydro's electrical grid make up the Purchase Areas and Zone II. Load estimates for Fort Nelson are not included in the Integrated System load forecast as it is connected to the Alberta transmission grid rather than to the BC Hydro grid.

The Purchase Area consists of six locations in the South Interior, namely Lardeau, Crowsnest, Newgate, Kingsgate-Yahk, Kelly Lake, and Keenleyside Dam. To serve customers in the Purchase Area, BC Hydro purchases electricity from a number of neighbouring electric utilities. Zone II consists of ten locations in the Northern Region, namely Masset, Sandspit, Atlin, Dease Lake, Eddontenajon, Telegraph Creek, Anahim Lake, Bella Bella, Bella Coola and Toad River.

In F2011, total gross requirements for the Purchase Area, Zone II, and Fort Nelson were 16 GWh, 112 GWh, and 195 GWh, respectively. In total, NIA total gross requirements represented about 0.6% of total BC Hydro's total gross energy requirements

9.1.1 Forecast Drivers

For the Purchase Area, the forecast is developed by a trend analysis of the total energy and capacity requirements for each location. For Zone II and Fort Nelson, forecasts are developed on a customer sector basis. The drivers for residential sales are housing starts and the average annual use per account. A housing starts forecast is provided by external sources and the forecast of average annual use per account is assumed to grow at the same rate as the rest of the Northern Region. For Zone II, the driver for commercial and industrial sales is the population forecast as provided by BC Stats.

For the Fort Nelson area, the driver for small commercial and industrial sales is an employment forecast. The large industrial accounts at the distribution and transmission level represent a significant part of the load and are forecasted separately. Increased oil and gas activity in the Horn River Basin is anticipated to cause an increase in sales in the Fort Nelson area in general. As a result, sales within the city of Fort Nelson are expected to have the highest growth rates amongst all NIA communities.

9.1.2 Trends and Risks

Tables 9.1, 9.2 and 9.3 show the sales, total gross energy requirements and total peak demand forecast for the Purchase Area, Zone II and Fort Nelson.

Total Gross Requirements within Zone II grew at a rate of 1.3% over the last five years and are expected to grow by 1.2%, 0.8% and 0.4% over the next five, 11 and 21 years, respectively. Fort Nelson total gross requirements declined by about 10% since F2009 mainly due to reduced sales to the wood products sector. Total sales in Fort Nelson are expected to recover in the near term and grow relatively steadily thereafter. This growth will be fostered by future oil and gas activity which is anticipated to enhance sales to residential and commercial customers connected to the Fort Nelson distribution system. In addition, gains in sales to larger conventional oil and gas customers are expected over the forecast period. Unlike the 2010 Forecast, energy and peak demand requirements for unconventional gas producers within the Horn River Basin are not included in the current load projections for Fort Nelson. BC Hydro has constructed scenarios that examine various Horn River shale gas play load requirements and alternatives on how to supply these loads. These scenarios are examined in BC Hydro's Integrated Resource Planning process.

The main risks to the NIA forecast are discrete events such as the opening or closing of large accounts and the rate of natural gas development in northeast B.C. This is primarily impacted by natural gas prices and prospects for increased gas exports.

Table 9.1 NIA Total Gross Requirements before DSM with Rate Impacts

Fiscal Year	Total Gross Requirements in Non-Integrated Areas (GWh)			
	Purchase Area	Zone II	Fort Nelson	Total NIA
Actual				
F2006	19	105	173	297
F2007	16	109	169	294
F2008	15	113	173	300
F2009	13	116	216	344
F2010	14	111	189	314
F2011	16	112	195	323
Forecast				
F2012	14	114	180	309
F2013	14	116	214	344
F2014	14	117	280	412
F2015	14	118	295	428
F2016	14	119	307	441
F2017	14	120	320	455
F2018	14	121	325	460
F2019	15	122	330	466
F2020	15	122	328	465
F2021	15	122	324	461
F2022	15	122	321	457
F2023	15	122	318	454
F2024	15	122	317	453
F2025	15	122	315	452
F2026	15	122	315	452
F2027	15	122	315	452
F2028	15	123	314	452
F2029	15	123	314	452
F2030	15	123	314	452
F2031	15	123	314	452
F2032	15	123	314	452
Growth Rates				
5 years: F2006 to F2011	-3.4%	1.3%	2.4%	1.7%
5 years: F2011 to F2016	-2.6%	1.2%	9.5%	6.4%
11 years: F2011 to F2022	-0.6%	0.8%	4.6%	3.2%
21 years: F2011 to F2032	-0.3%	0.4%	2.3%	1.6%

Table 9.2 NIA Peak Demand Requirements before DSM with Rate Impacts

Fiscal Year	Non-Integrated Area Peak Demand (MW)			
	Purchase Area	Zone II	Fort Nelson	Total NIA
Actual				
F2006	5	21	34	61
F2007	5	24	29	58
F2008	4	25	28	57
F2009	4	25	34	62
F2010	4	25	31	60
F2011	5	24	29	58
Forecast				
F2012	4	25	31	60
F2013	4	26	33	63
F2014	4	26	41	71
F2015	4	26	43	73
F2016	4	26	45	75
F2017	4	27	47	77
F2018	4	27	48	79
F2019	4	27	49	80
F2020	4	27	48	80
F2021	4	27	48	79
F2022	4	27	47	78
F2023	4	27	46	78
F2024	4	27	46	77
F2025	4	27	46	77
F2026	4	27	46	77
F2027	4	27	46	77
F2028	4	27	46	77
F2029	4	27	46	77
F2030	4	27	46	77
F2031	4	27	46	77
F2032	4	27	46	77
Growth Rates:				
5 years: F2006 to F2011	-3.2%	2.8%	-3.4%	-1.0%
5 years: F2011 to F2016	-2.1%	1.5%	9.2%	5.4%
11 years: F2011 to F2022	-0.8%	0.9%	4.5%	2.8%
21 years: F2011 to F2032	-0.2%	0.5%	2.2%	1.4%

Note: NIA peak requirements, including Fort Nelson, are not included in the peak demand forecast shown in Chapter 10.

9.2 Other Utilities

The other utilities served by BC Hydro are: City of New Westminster, FortisBC, Seattle City Light and Hyder. The City of New Westminster is surrounded by BC Hydro's Lower Mainland region. The Fortis BC service area is part of southeastern B.C., Seattle City Light is in the state of Washington, and Hyder is in the state of Alaska. Hyder is served at distribution voltage whereas the other three utilities are served at transmission voltage.

Pursuant to a BCUC decision dated June 9, 1993, BC Hydro is obligated to provide FortisBC with up to 200 MW of capacity and associated energy under tariff rates.

BC Hydro is obligated to serve Seattle City Light in accordance with a treaty between British Columbia and Seattle dated March 30, 1984. The treaty expires on January 1, 2066.

The community of Stewart, B.C. is connected to BC Hydro's grid. Since Hyder, Alaska is only five km away from Stewart, BC Hydro also serves the Alaskan community.

In F2011, annual energy sales to City of New Westminster, FortisBC, Seattle City Light, and Hyder were 449 GWh, 523 GWh, 316 GWh, and 1 GWh, respectively.

9.2.1 Forecast Drivers

The forecast for the City of New Westminster is based on trend analysis and information from BC Hydro's distribution planners on new potential larger projects. Previously, the forecast of sales to FortisBC was based on information received annually from that utility. For the 2011 Forecast, projected sales to FortisBC are based on recent actual sales trends whereas the longer-term forecast is developed by applying a smoothed transition to the short-term forecast. The forecast for Seattle City Light is prescribed within the treaty, and the sales forecast for Hyder remains at 1 GWh per year.

9.2.2 Trends and Risks

The City of New Westminster is forecast to have modest average annual growth rate of about 1.3 per cent over the entire forecast period. The forecast for sales to FortisBC is lower than last year's forecast given that sales have been historically declining. Both Seattle City Light and Hyder are forecast to have no significant growth.

The main risk to the forecast for the City of New Westminster is a discrete event such as a large new account. The main risk to the forecast for FortisBC would be a possible change in how that utility plans to meet its supply requirements. Given that the forecast for Seattle City Light is based on a signed treaty, there is minimal sales risk over the entire forecast period. The sales risk for Hyder is also minimal given that its load is so small.

Table 9.3 Sales to Other Utilities before DSM and Rate Impacts (GWh)

Fiscal Year	Sales to Other Utilities (GWh)				
	City of New Westminster	Fortis BC	Seattle City Light	Hyder, Alaska	Total Other Utilities
Actual					
F2006	415	820	320	1	1,556
F2007	429	972	310	1	1,712
F2008	442	921	310	1	1,674
F2009	440	851	306	1	1,598
F2010	444	754	305	1	1,504
F2011	449	523	316	1	1,289
Forecast					
F2012	462	520	312	1	1,295
F2013	471	640	310	1	1,422
F2014	479	774	310	1	1,564
F2015	486	907	310	1	1,705
F2016	493	1,041	312	1	1,847
F2017	500	1,041	310	1	1,853
F2018	507	1,041	310	1	1,859
F2019	514	1,041	310	1	1,867
F2020	521	1,041	312	1	1,875
F2021	529	1,041	310	1	1,882
F2022	537	1,041	310	1	1,889
F2023	545	1,041	310	1	1,897
F2024	553	1,041	312	1	1,907
F2025	561	1,041	310	1	1,913
F2026	569	1,041	310	1	1,921
F2027	577	1,041	310	1	1,929
F2028	585	1,041	312	1	1,939
F2029	593	1,041	310	1	1,945
F2030	601	1,041	310	1	1,953
F2031	609	1,041	310	1	1,961
F2032	617	1,041	312	1	1,971
Growth Rates					
5 years: F2006 to F2011	1.6%	-8.6%	-0.3%	-4.1%	-3.7%
5 years: F2011 to F2016	1.9%	14.8%	-0.3%	1.4%	7.5%
11 years: F2011 to F2022	1.6%	6.5%	-0.2%	0.6%	3.5%
21 years: F2011 to F2032	1.5%	3.3%	-0.1%	0.3%	2.0%

10 Peak Demand Forecast

10.1 Peak Description

BC Hydro's peak demand is defined as the maximum expected amount of electricity consumed in a single hour under an average cold temperature assumption (i.e., design temperature). BC Hydro is a winter peaking utility, as its demand is more sensitive to colder temperatures than it is to warmer temperatures. BC Hydro's integrated system typically reaches its annual peak on a cold winter day between 5:00 pm and 6:00 pm. Vancouver Island has both a morning and an evening peak as residential space heating is a larger component of the Island load.

Domestic peak demand includes distribution substation peaks, transmission customer peaks, City of New Westminster peaks, and system transmission losses. The integrated system peak demand is the domestic peak demand plus the peak demands from the other served utilities including Fortis BC and associated transmission losses.

Distribution substation peaks are the most sensitive to ambient temperature. The distribution peak demand is driven by various factors including growth in residential accounts and in energy sales. In addition, larger discrete loads such as shopping malls, waste treatment facilities and other infrastructure projects contribute to peak load growth at specific distribution substations.

Transmission peak demand is less responsive to weather but is sensitive to external market conditions and demand changes for B.C.'s key industrial commodities such as wood, pulp and paper and metals.

10.2 Peak Demand Forecast – Integrated System

The comparative peak demand forecasts (2011 Forecast vs. 2010 Forecast) presented in this section are before DSM and with rate impacts. The forecasts below include the impact of electric vehicles and adjustments for DSM savings overlaps from codes and standards.

BC Hydro's all-time total domestic system peak was 10,113 MW which occurred on November 29, 2006. The daily average temperature for that day recorded at the Vancouver International Airport (YVR) was -5.9 ºC[9]. For F2011, the actual domestic peak demand of 9,790 MW was recorded at 6:00 pm on November 23, 2010. The average temperature for the day at YVR was -6.4 ºC. The weather-adjusted domestic peak for the winter of F2011 was estimated at 10,047 MW.

For F2011, the total integrated system peak demand forecast (including requirements from the other utilities served by BC Hydro), was 10,203 MW before weather adjustments and 10,335 MW after weather adjustments. Peak demand (excluding Initial LNG Load) is expected to grow from to 12,140 MW in F2016, 13,197 MW in F2022 and 15,174 MW in F2032. These increases represent annual growth rates of 3.3 percent over the next five years, 2.2 percent during F2011-22 and 1.8 percent over the entire 21-year forecast period[10].

Between F2010 and F2011, the total domestic system peak demand (weather-adjusted) decreased slightly by 6 MW or 0.1% as the coincident distribution peak demand (weather-adjusted) increased by 154 MW or about 2.0%. The coincident transmission peak demand

[9] The total BC Hydro distribution peak is the sum of four distribution peaks for the four main service regions. Each of the four distribution peaks has a design temperature based on the rolling average of the annual coldest daily average temperature over the most recent 30 years. The design temperatures are -5.3 ºC for the Lower Mainland, -3.6 ºC for Vancouver Island; -16.4 ºC for South Interior and -28.5 ºC for the Northern Region.
[10] Including the impact of the Initial LNG Load, the 5, 11 and 21-year annual growth rates for peak demand are 3.8 percent, 2.7 percent and 2.1 percent, respectively.

(excluding weather adjustments) decreased by 160 MW or 10.4 % over the same time period.

10.3 Comparison of Peak Demand Forecasts

10.3.1 Distribution Peak

Figure 10.1 and Table 10.1 compare the BC Hydro coincident distribution substation peak demand forecasts for the 2010 and 2011 Forecasts before DSM and with rate impacts.

In the short term, the distribution peak demand forecast is below last year’s forecast. Since there was little growth in the distribution system during F2011, this year’s forecast starts from a lower point than was anticipated in the 2010 Forecast. Slower growth in residential accounts is projected in this year’s forecast has also contributed to a lower forecast.

A reduction in energy sales for the wood sector has led to a lower expected growth in peak demand from this sector over the short term. In addition, a lower peak demand is expected from oil and gas loads in current forecast relative to the 2010 Forecast.

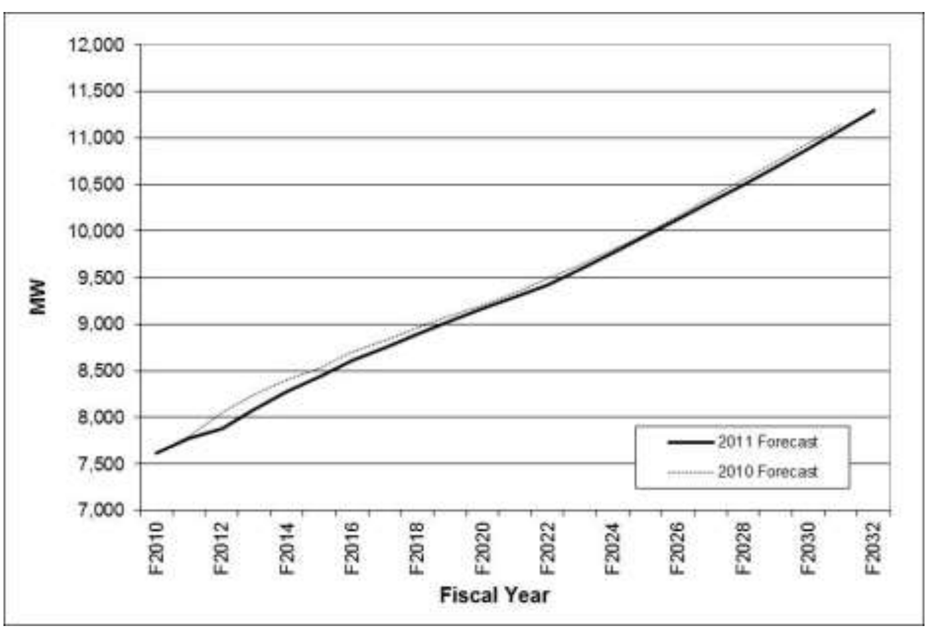
Over the medium to long term, the 2011 Forecast of distribution peak demand is very close to last year’s forecast. Factors that contribute to this are: (i) housing starts are expected to be stronger; (ii) large-scale municipal projects will create additional peak demand within the Lower Mainland; and (iii) the distribution connection of oil and gas and mining customers is expected to contribute to growth in the distribution peak.

Table 10.1 Comparison of BC Hydro's Distribution Peak Demand Forecasts before DSM with Rate Impacts

	Distribution Peak Demand (MW)			
Fiscal Year	**2011 Forecast**	**2010 Forecast**	**2011 Forecast Less 2010 Forecast**	**% Difference**
F2010	7,615*	7,615*	-	0.0%
F2011	7,771*	7,793	-22	-0.3%
F2012	7,879	8,051	-172	-2.1%
F2013	8,079	8,246	-166	-2.0%
F2014	8,281	8,403	-122	-1.5%
F2015	8,441	8,526	-84	-1.0%
F2016	8,608	8,696	-88	-1.0%
F2017	8,748	8,823	-74	-0.8%
F2018	8,892	8,959	-67	-0.8%
F2019	9,029	9,085	-55	-0.6%
F2020	9,167	9,207	-40	-0.4%
F2021	9,290	9,341	-52	-0.6%
F2022	9,417	9,486	-69	-0.7%
F2023	9,595	9,638	-43	-0.4%
F2024	9,768	9,799	-31	-0.3%
F2025	9,945	9,969	-24	-0.2%
F2026	10,125	10,168	-43	-0.4%
F2027	10,309	10,359	-50	-0.5%
F2028	10,497	10,555	-58	-0.6%
F2029	10,689	10,748	-59	-0.6%
F2030	10,885	10,938	-53	-0.5%
F2031	11,085	11,147	-62	-0.6%
F2032	11,289			

* = Weather Normalized Actual

Figure 10.1 Comparison of BC Hydro's Distribution Peak Demand Forecast before DSM with Rate Impacts



10.3.2 Transmission Peak

Figure 10.2.1 and Table 10.2.1 compare the 2010 and 2011 BC Hydro total coincident transmission peak forecast before DSM and with rate impacts, excluding Initial LNG peak demand. Table 10.2.2 and Figure 10.2.2 compare the total 2011 transmission peak demand, including Initial LNG peak demand, to the 2010 Forecast. A description of the Initial LNG Load is provided in Appendix 3.1.

The recent historical decline in the transmission peak reflects lower demand in the forestry sector. For F2012, BC Hydro’s transmission peak demand is expected to continue to remain lower due to factors such as reduced peak loads from large pulp and paper transmission customers, weak U.S. housing demand and reduced peak loads from other sectors including pipelines and transportation. In addition, transmission peak demand in the short term is lower due to revised information (i.e. startup dates) on peak demand for new mines.

Over the medium term, the transmission peak forecast is above the 2010 Forecast. It is anticipated that as economic conditions continue to improve, commodity prices are likely to be higher, especially for metals. As a result, some existing mines are expected to expand their operations. For example, BC Hydro’s largest mining customer, Highland Valley Copper, has announced that it will extend its operations an additional six years to F2026 rather than shutting in F2020 as assumed in last year’s forecast. As well, other mining customers have also indicated that their operations will be extended. Growth in peak demand from the oil and gas activity in the Dawson Creek Area is anticipated to be robust. This also explains the increase in the transmission peak in the medium term of the forecast.

10.3.3 Integrated System Peak

Tables 10.3.1 and 10.3.2 and Figures 10.3.1and 10.3.2 compare the total integrated system peak demand forecasts for the 2010 and 2011 Forecasts before DSM and with rate impacts (with and without Initial LNG Load). The integrated peak demand forecast is the sum of the peak forecast for coincident distribution, transmission, and other utilities plus system transmission losses.

Table 10.2.1 Comparison of BC Hydro's Transmission Peak Demand Forecast before DSM with Rate Impacts (excluding Initial LNG)

Fiscal Year	Transmission Peak Demand (MW)			
	2011 Forecast (excluding Initial LNG)	2010 Forecast	2011 Forecast Less 2010 Forecast	% Difference
F2010	1,545*	1,545*		
F2011	1,385 *	1,537	-152	-9.9%
F2012	1,515	1,734	-219	-12.6%
F2013	1,659	1,774	-115	-6.5%
F2014	1,896	1,929	-33	-1.7%
F2015	2,036	2,159	-123	-5.7%
F2016	2,151	2,224	-73	-3.3%
F2017	2,239	2,243	-4	-0.2%
F2018	2,249	2,237	12	0.5%
F2019	2,275	2,234	41	1.8%
F2020	2,308	2,237	70	3.1%
F2021	2,303	2,179	124	5.7%
F2022	2,307	2,196	111	5.1%
F2023	2,297	2,219	78	3.5%
F2024	2,304	2,244	60	2.7%
F2025	2,309	2,279	29	1.3%
F2026	2,233	2,253	-20	-0.9%
F2027	2,169	2,271	-102	-4.5%
F2028	2,174	2,316	-142	-6.1%
F2029	2,170	2,311	-141	-6.1%
F2030	2,191	2,311	-120	-5.2%
F2031	2,240	2,311	-71	-3.1%
F2032	2,246			

* = Actual

Figure 10.2.1 Comparison of Transmission Peak Demand Forecast before DSM with Rate Impacts (excluding Initial LNG)

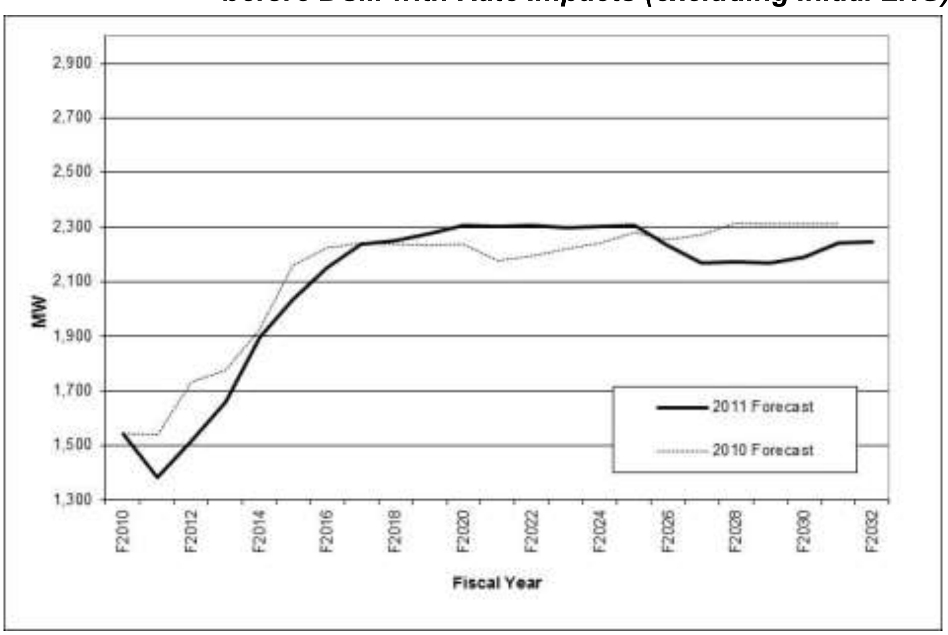


Table 10.2.2 Comparison of BC Hydro's Transmission Peak Demand Forecast before DSM with Rate Impacts (including Initial LNG)

Fiscal Year	Transmission Peak Demand (MW)			
	2011 Forecast (including Initial LNG)	2010 Forecast	2011 Forecast Less 2010 Forecast	% Difference
F2010	1,545*	1,545*		
F2011	1,385*	1,537	(152)	-9.9%
F2012	1,515	1,734	(219)	-12.6%
F2013	1,659	1,774	(115)	-6.5%
F2014	1,896	1,929	(33)	-1.7%
F2015	2,036	2,159	(123)	-5.7%
F2016	2,426	2,224	202	9.1%
F2017	2,865	2,243	622	27.7%
F2018	2,875	2,237	638	28.5%
F2019	2,901	2,234	667	29.8%
F2020	2,934	2,237	696	31.1%
F2021	2,929	2,179	750	34.4%
F2022	2,933	2,196	737	33.6%
F2023	2,923	2,219	704	31.7%
F2024	2,930	2,244	686	30.6%
F2025	2,935	2,279	655	28.7%
F2026	2,859	2,253	606	26.9%
F2027	2,795	2,271	524	23.1%
F2028	2,800	2,316	484	20.9%
F2029	2,796	2,311	485	21.0%
F2030	2,817	2,311	506	21.9%
F2031	2,866	2,311	555	24.0%
F2032	2,872			

* = Actual

Figure 10.2.2 Comparison of Transmission Peak Demand Forecast before DSM with Rate Impacts (including Initial LNG)

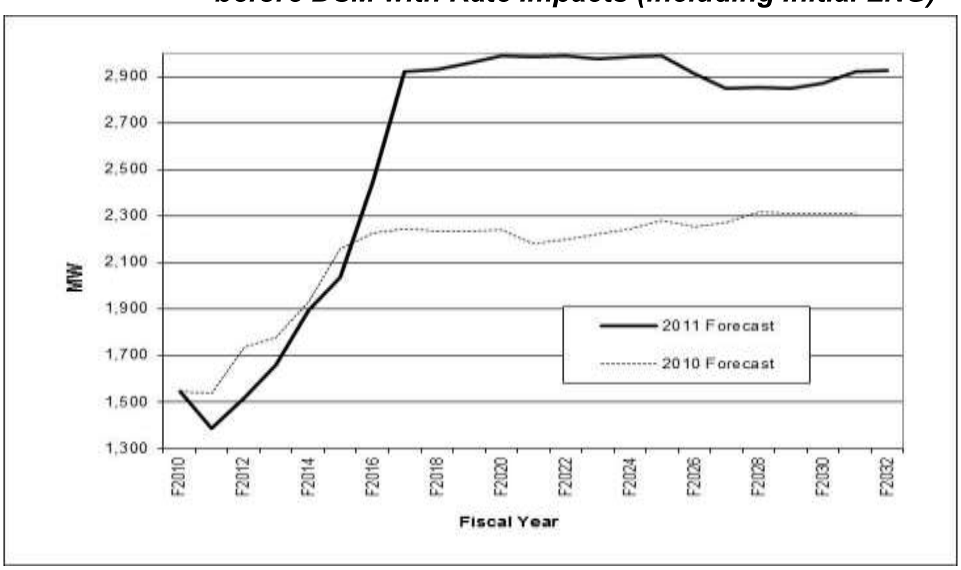


Table 10.3.1 Comparison of Total Integrated Peak Demand Forecast before DSM with Rate Impacts (excluding Initial LNG)

Fiscal Year	Integrated System – Peak Demand (MW)			
	2011 Forecast	2010 Forecast	2011 Forecast Less 2010 Forecast	% Difference
F2010	10,344*	10,344*		
F2011	10,335*	10,580	-245	-2.3%
F2012	10,651	11,078	-427	-3.9%
F2013	11,026	11,338	-312	-2.7%
F2014	11,505	11,681	-175	-1.5%
F2015	11,832	12,066	-233	-1.9%
F2016	12,140	12,323	-183	-1.5%
F2017	12,389	12,484	-94	-0.8%
F2018	12,558	12,627	-69	-0.5%
F2019	12,737	12,762	-25	-0.2%
F2020	12,923	12,899	24	0.2%
F2021	13,053	12,983	69	0.5%
F2022	13,197	13,160	37	0.3%
F2023	13,382	13,352	29	0.2%
F2024	13,579	13,554	25	0.2%
F2025	13,775	13,778	-2	0.0%
F2026	13,891	13,966	-75	-0.5%
F2027	14,021	14,194	-173	-1.2%
F2028	14,232	14,456	-224	-1.5%
F2029	14,436	14,661	-224	-1.5%
F2030	14,673	14,867	-194	-1.3%
F2031	14,945	15,096	-151	-1.0%
F2032	15,174			

* = Weather Normalized Actual

Figure 10.3.1 Comparison of BC Hydro's Integrated System Peak Demand Forecast before DSM with Rate Impacts (excluding Initial LNG)

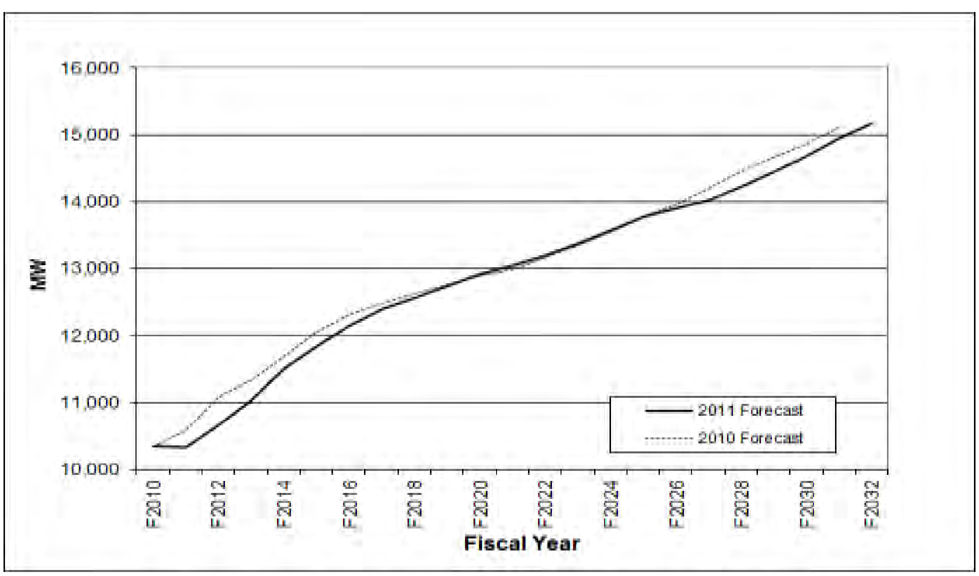
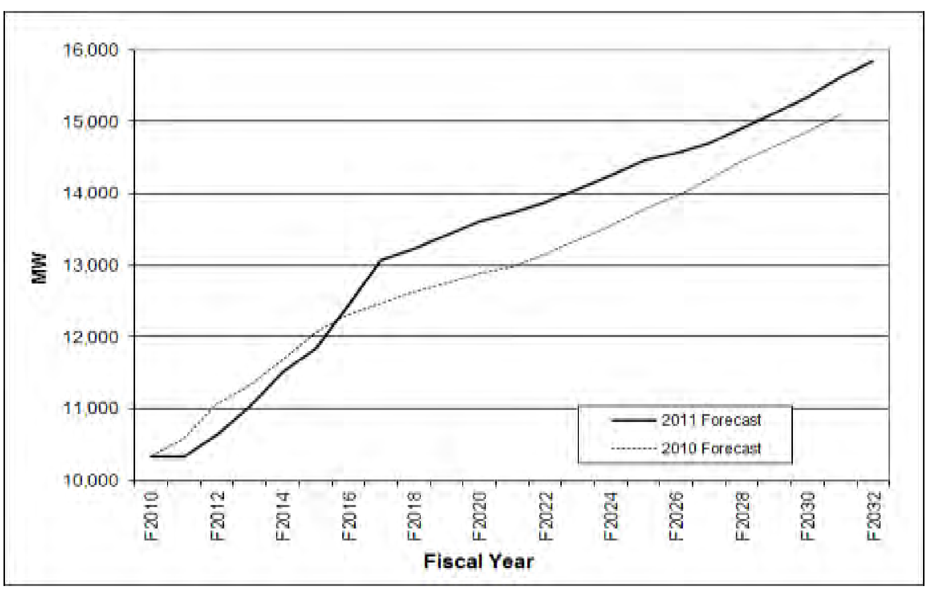


Table 10.3.2 Comparison of Total Integrated Peak Demand Forecast before DSM with Rate Impacts (including Initial LNG)

Fiscal Year	Integrated System – Peak Demand (MW)			
	2011 Forecast	2010 Forecast	2011 Forecast Less 2010 Forecast	% Difference
F2010	10,344*	10,344*		
F2011	10,335*	10,580	-245	-2.3%
F2012	10,656	11,078	-422	-3.8%
F2013	11,030	11,338	-308	-2.7%
F2014	11,509	11,681	-172	-1.5%
F2015	11,845	12,066	-221	-1.8%
F2016	12,439	12,323	116	0.9%
F2017	13,070	12,484	586	4.7%
F2018	13,238	12,627	611	4.8%
F2019	13,418	12,762	656	5.1%
F2020	13,604	12,899	704	5.5%
F2021	13,733	12,983	750	5.8%
F2022	13,878	13,160	717	5.5%
F2023	14,062	13,352	710	5.3%
F2024	14,259	13,554	705	5.2%
F2025	14,456	13,778	678	4.9%
F2026	14,571	13,966	606	4.3%
F2027	14,701	14,194	508	3.6%
F2028	14,913	14,456	457	3.2%
F2029	15,117	14,661	456	3.1%
F2030	15,354	14,867	486	3.3%
F2031	15,625	15,096	529	3.5%
F2032	15,855			

* = Weather Normalized Actual

Figure 10.3.2 Comparison BC Hydro's Integrated System Peak Demand Forecast before DSM with Rate Impacts (including Initial LNG)



10.4 Peak Demand Forecast Methodology

This section provides an overview of how the distribution, transmission and total system peak demand forecast is developed. The detailed methodology is described in section Appendix A1.3. The methodology description excludes additional peak load impacts of electric vehicles and the DSM overlap between codes and standards. These additional adjustments to the distribution peak forecasts are shown in Appendices 4 and 5.

10.4.1 Distribution Peak Methodology

At the distribution level, electricity demand is closely linked to the historical trends in distribution substation load growth and the economic outlook for each forecast region. Thus, the regional economic outlook is one of the primary inputs into distribution peak demand forecasts, with such input being provided to BC Hydro by Stokes Consulting.

The distribution peak forecast is developed using forecasts from two main sources: (1) outputs from an econometric model referred to as the distribution peak guideline forecast; and (2) load forecasts for each of BC Hydro's distribution substations. The substation forecasts are based on the growth in the guideline forecasts, expected transfers among substations and anticipated new large loads (i.e., discrete projects) that are specific to each substation.

The distribution peak guideline forecast is prepared for 15 different planning areas for the first 11 years of the forecast period. The forecast provides a guideline for the total non-coincident (MVA) growth for all of the substations serving distribution customers in that area. The main stock drivers used in the model are the forecasts of employment and the number of residential customer accounts, which is driven by housing starts.

After the distribution peak guideline and substation forecasts are completed for each of the 15 areas, a final distribution peak forecast is prepared. These forecasts are aggregated for the 15 planning areas to develop a total distribution substation peak for each the four major service regions (Lower Mainland, Vancouver Island, South Interior and Northern Region). Regional power factors and coincidence factors are applied to aggregated forecasts to produce four regional coincident distribution peak forecasts in MW. For the last 10 years of the forecast period, the distribution peak forecast for each region is derived using the growth rate in the distribution energy sales forecast.

A total BC Hydro distribution substation peak forecast is prepared as a coincident sum of the four regional distribution peak forecasts.

The equations and other details describing the development of the distribution peak forecast are contained in Appendix A1.3.

10.4.2 Transmission Peak Methodology

The transmission peak demand forecast is prepared on a customer-by-customer account basis for the entire forecast period. Individual transmission customer forecasts are developed using market intelligence from BC Hydro's key account managers, historical peak demand trends, reports on industry outlooks, plus production and intensity estimates. These forecasts are aggregated into regional peak forecasts (i.e.; a total transmission peak demand forecast) for each of the four main service regions. Regional coincidence factors and power factors are applied to each of these total regional peak forecasts to establish regional coincident transmission peak forecasts.

A total BC Hydro transmission peak demand forecast is prepared as a coincident sum of the four regional transmission peak forecasts. The equations and other details describing the development of the transmission peak forecast are located in Appendix A1.3.

10.4.3 Integrated System Peak Forecast Methodology

A total system peak demand forecast is prepared as the sum of the total coincident distribution peak, total coincident transmission peak, peak demands for other utilities and total system transmission losses. The coincident distribution peak and transmission peak forecasts are informed from the individual substation forecasts. As such, the substation demands at the distribution and transmission level are counted once in developing the total system peak forecast. The system transmission losses are assumed as eight percent of the total system peak demand forecast.

The system peak demand forecast is prepared for the BC Hydro's domestic system and the total integrated system. The domestic peak demand is the sum of the total domestic distribution and transmission peaks, the peak demand of the City of New Westminster and system transmission losses. The integrated system peak demand is the domestic peak demand plus the peak demands from the other utilities (i.e., Seattle City Light and FortisBC) and system transmission losses.

10.5 Risks and Uncertainties

Uncertainties and risks in the peak demand forecast come from several factors such as the assumptions on the growth of forecast drivers and model parameters to the anticipated normal weather assumption and its impact on the peak demand.

Upward Pressure on Peak Demand:

- The strong housing demand in B.C. as evidenced by residential accounts growth;
- Stronger regional growth in employment;
- Continued high commodity prices and market demand for B.C.'s exports; and
- More discrete distribution-connected spot loads.

Downward Pressure on Peak Demand:

- Slowdown in the housing market with more vacancies and less development than expected;
- Lower commodity prices and a slowdown in the U.S. or Asian economies; and
- Pine beetle infestation resulting in additional forestry sector challenges.

BC Hydro quantifies the overall uncertainty in the peak demand using the results of the Monte Carlo uncertainty model as described in Chapter 5.

11 Glossary

Accrued Sales are an estimate of electricity delivered within a specific month. Most customer meters are not read at every month-end, so the amount of electricity delivered in a month is not known precisely. In accordance with GAAP, monthly accrued sales are used for monthly financial reporting.

Backcasting Estimating econometric or other models over a historical time period and comparing the predictions of the models to actual results over the same time period.

Billed Sales The amount of electricity billed. Because bills are produced after the electricity has been delivered, monthly billed sales lag monthly delivery of electricity.

Binary Variable is a variable whose value is either zero or one. Binary variables are often used as independent variables in regression models in order to account for events that either occur or do not occur. In this latter context, binary variables are often referred to as “dummy variables” in regression.

Calibration Estimating econometric or other models over a historical time period.

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.

Commercial Output Commercial output focuses on the provisions of services in the economy and so includes such things as public administration, insurance agents, bankers, wholesale and retail trade, food services, accommodation provisions etc.

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.

Cooling Degree Day (CDD) is a measure of warmness, defined by the number of degrees above 18 degrees Celsius for the average daily temperature. CDDs are drivers of utility air-conditioning electricity loads.

Demand-Side Management (DSM) Activities that occur on the demand side of the revenue meter and are influenced by the utility. DSM activities result in a change in electricity sales. Past DSM savings include incremental load displacement and energy efficiency savings. Note that BC Hydro’s historical sales include the impact of DSM savings realized up to that year.

Design Temperature Rolling average of the coldest daily average temperature over the most recent 30 years

Distribution voltage customer A BC Hydro customer who receives electricity via distribution lines that operates at lower voltages (60 kV and less).

Domestic System Peak includes the peak requirements for BC Hydro’s distribution and transmission customers in its service territory; sales to the City of New Westminster and system transmission and distribution losses.

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 (e.g. 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.

Energy Efficiency Is the ratio of the energy service delivered from a process or piece of equipment to the energy input. Energy efficiency is a dimensionless number, with a value between 0 and 1 or, when multiplied by 100, is given as a percentage.

EV Electric Vehicle

GAAP Generally Accepted Accounting Principles

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

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.

Heating Degree Day (HDD) Is a measure of coldness, defined by the number of degrees below 18 degrees Celsius for the average daily temperature. HDDs are drivers of utility space heating electricity loads.

Integrated System That portion of the BC Hydro electricity system which is connected as one whole by a high voltage transmission grid.

Integrated System Peak includes the peak requirements for BC Hydro’s distribution and transmission customers in its service territory; sales to Other Utilities, which includes Seattle City Light, New Westminster, Fortis BC and Hyder Alaska (Tongass Power and Light Co. Inc.); and system transmission and distribution losses.

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.

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)

Liquefied Natural Gas (LNG) is natural gas that has been converted temporarily to liquid form for ease of storage or transport. This process involves refrigeration, and requires no chemical transformations.

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

Load Displacement Projects that involve the installation of self-generation facilities at customer sites, with the electricity generated being used on-site by the customer, with a resultant decrease in the purchase of electricity from BC Hydro.

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.)

Megawatt-hour (MWh) A measure of electrical energy, equivalent to 1,000 kWh. (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.

Megavolt-Amps (MVA) – a unit of apparent power, which 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.

Non-coincident In general is the magnitude of a region's (or customer's or group of customers') demand at the time of its peak.

Non-Integrated Area (NIA) Non-integrated facilities refer to generating facilities that are not connected to the system, located in remote areas of the province

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

Ordinary Least Squares (OLS) is a method of estimating parameters to minimize the sum of squares errors in a regression model.

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 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 close to 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.

Reference Forecast before DSM and Rate Impacts is the energy and peak demand forecast developed under the current methodology. It is developed under the assumption that electricity rates increase at the rate of inflation and normal weather conditions.

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

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 Coincident 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 equivalence is:

1 kilowatt (kW)	=	1,000 watts
1 megawatt (MW)	=	1,000 kilowatts or 1 million watts
1 kilowatt-hour (kWh)	=	1,000 watt-hours
1 megawatt-hour (MWh)	=	1,000 kilowatt-hours or 1 million watt-hours
1 gigawatt-hour (GWh)	=	1,000 megawatt-hours or 1 billion watt-hours

Appendix 1 Forecast Processes and Methodologies

There are a number of key components to the demand and sales forecast: the residential forecast; the commercial forecast (distribution and transmission voltage), the industrial forecast (distribution voltage and transmission voltage), and the regional and system peak forecasts. The peak forecast includes the distribution voltage and transmission voltage peak demands. This section covers the methodology used for these forecast components.

A1.1. Statistically Adjusted Forecast Methodology

Distribution

BC Hydro forecasts residential and commercial distribution sales[11] by using the Statistically Adjusted End-Use model (SAE). This model incorporates end-use information, economic data, weather data and market data to construct regional forecasts.

The statistically adjusted end-use modeling framework begins by defining energy use (Use_m) in year and month (m) as the sum of energy used by heating equipment ($Heat_m$), cooling equipment ($Cool_m$), and other equipment ($Other_m$). Formally,

$$\text{(A1.1)} \qquad USE_m = Heat_m + Cool_m + \mathrm{Other}_m$$

Equation (A1.1) can be shown in a regression form, as shown below in (A1.2):

$$\text{(A1.2)} \qquad USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, economic drivers, dwelling data and weather data and ε_m is the error term for the regression. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated coefficients are the adjustment factors or the relative contribution by the major end uses to the total consumption.

The equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on the end use models.

BC Hydro also includes other variables in equation A1.2. Other variables include binary variables to account for migration of accounts between customer classes. In addition seasonal variables are included.

<u>Constructing XHeat</u>. Space heating energy is specified to depend on the following types of variables:

- Heating degree days (weather),
- Heating equipment saturation levels (fraction of building stock for the commercial sector),

[11] The commercial sales are composed of commercial general rate class, transmission and BC Hydro Own Use, Irrigation, Street-lighting. The SAE model is used to forecast the sales for the commercial general rate class. The sales forecast for BC Hydro Own Use, Irrigation, and Street-lighting is done using historical sales data and trend analysis. The SAE models are calibrated over a 10 year rolling period.

- Assumptions about heating equipment operating efficiencies,
- Average number of days in the billing cycle for each month,
- Economic variables include employment, retail sales and commercial output.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$\text{(A1.3)} \qquad XHeat_m = HeatIndex_m \times HeatUse_m$$

where, $XHeat_m$ is estimated heating energy use in a year (y) and month (m), $HeatIndex_y$ is the annual index of heating equipment in the year (y), and $HeatUse_m$ is the monthly usage multiplier.

The sub equation for $HeatIndex_{\mathbf{m}}$ in (A1.3) is:

$$HeatIndex_y = \sum_{spaceheating} EndUseEnergy_{e,BaseYear} \times \frac{\left(Share_y \big/ Eff_y \right)}{\left(Share_{BaseYear} \big/ Eff_{BaseYear} \right)}$$

Where, y means year, e refers to the category of space heating, Share means saturation level of space heating, Eff means efficiency level of space heating based on Energy Information Administration (EIA) data

The sub equation for $XHeatUse_{\mathbf{m}}$ in (A1.3) is:

$HeatUse_{\mathbf{m}}$ = Commercial $GDPIndex^{\beta 1}{}_{\mathbf{m}}$ × $EmploymentIndex^{\beta 2}{}_{\mathbf{m}}$ × $RetailSalesIndex^{\beta 3}{}_{\mathbf{m}}$ × Heating Degree Days $Index_{\mathbf{m}}$.

Where m refers to month specific values and the β values are the elasticities that apply to the various regional economic indices above (i.e., commercial GDP, employment, and retail sales) and small commercial sales. The residential SAE model some of the economic drivers are different to the commercial sector economic drivers. The residential sector drivers include: disposable income, household sizes and weather as non-economic drivers. The economic indices for each variable are developed based on a 12 month rolling average of the economic variable weighted by its average monthly value in the last historical year.

The heating equipment index (HeatIndex) depends on the space heating equipment saturation levels normalized by average operating efficiency levels. As a result, the index will increase over time if there are increases in heating equipment saturation levels, and will decrease over time if there are improvements in equipment and building efficiency levels. Heating system usage levels (HeatUse) are driven on a monthly basis by economic variables and non-economic factors, such as weather (Heating Degree Days).

Constructing XCool. The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables:

- Cooling degree days (weather),

- Cooling equipment saturation levels (fraction of building stock for the commercial sector),
- Assumptions about cooling equipment operating efficiencies,
- Average number of days in the billing cycle for each month,
- Economic variables include employment, retail sales and commercial output.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

(A1.4) $$\mathrm{XCool}_m = \mathrm{CoolIndex}_m \times \mathrm{CoolUse}_m$$

where, XCool_m is estimated cooling energy use in a year and month (m),

$\mathrm{CoolIndex}_y$ is an index of cooling equipment for the year (y), and

$\mathrm{CoolUse}_m$ is the monthly usage multiplier.

As with space heating, the cooling equipment index (CoolIndex) depends on the cooling equipment saturation levels normalized by average operating efficiency levels. As a result, the cooling index will increase over time if there are changes in cooling equipment saturation levels, and will decrease over time if there are improvements in equipment efficiencies or the thermal efficiency of buildings. Space cooling system usage levels (CoolUse) are driven on a monthly basis by several factors, including weather (Cooling Degree Days) and similar economic factors used to develop heating usage.

Constructing XOther. Monthly estimates of consumption for non-weather sensitive end uses can be derived in a similar fashion. Non-weather sensitive end-uses include lighting, refrigeration, cooking, clothes washing and drying, entertainment and other miscellaneous equipment. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels,
- Appliance efficiency levels,
- Average number of days in the billing cycle for each month, and
- Economic variables include employment, retail sales and commercial output.

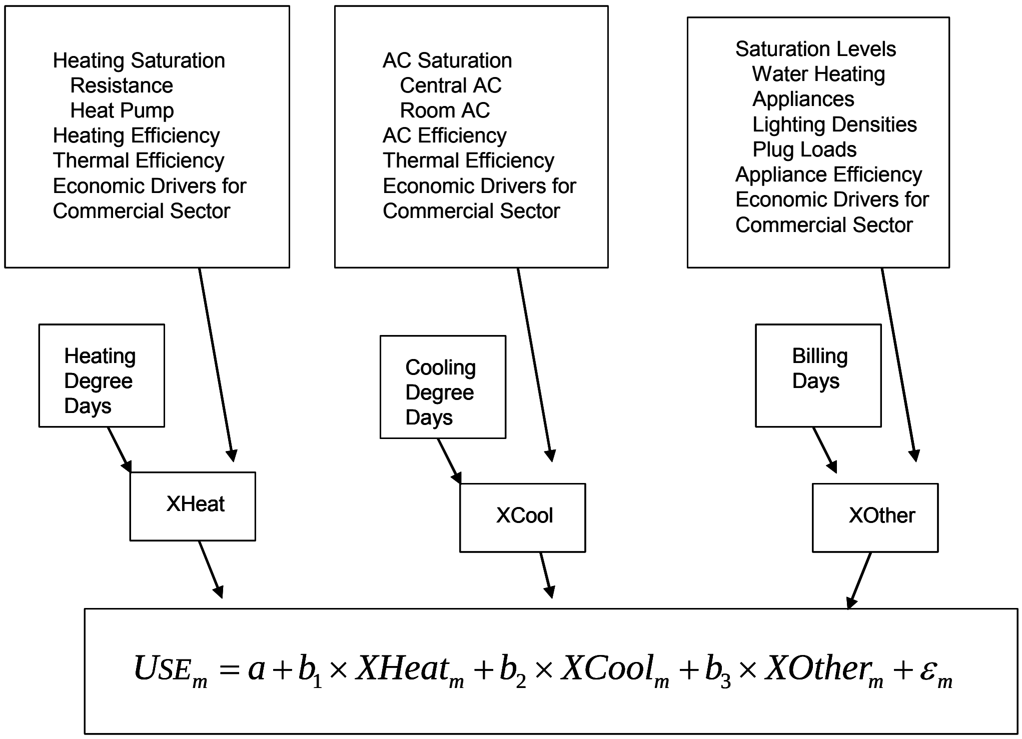
The explanatory variable for other uses is defined as follows:

(A1.5) $$XOther_m = OtherEqpIndex_m \times OtherUse_m$$

The first term on the right hand side of this expression ($\mathrm{OtherEqpIndex}_y$) embodies information about appliance saturation and efficiency levels. The second term (OtherUse) captures the impact of changes in economic variables that impact use of other equipment. These economic variables are similar to those used for explaining heating and cooling.

Figure A1.1 below summarized the inputs that are used in the construction of the regression variables (i.e. the predictor variables) for the commercial sector.

Figure A1.1 Statistically Adjusted End Use (SAE) Model



$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

The main reason BC Hydro adopted the statistically adjusted end use model for the commercial sector is to enhance transparency. In the 2005 Forecast, the commercial sector load forecast was based on a regression approach using GDP as the main driver. Since the 2006 Forecast, BC Hydro has run the SAE models for the distribution class by the four regions.

A1.2. Industrial Forecast Methodology

Industrial Distribution

As indicated in the industrial section, BC Hydro applies a regression model to estimate the sales for the remaining sectors of the industrial distribution customers. The customers do not include sectors such as wood, mining, and oil and gas but includes customers such as agriculture, chemical, and other types of manufacturing and processing. The methodology used to develop the forecast for oil and gas loads please see Appendix A3.2. For mining and wood, the methodology follows from production and intensity, where the production estimates come from third party consultants.

The industrial distribution energy forecast for the remaining segment is developed using regression methods based on the following expression:

(A1.6) $\text{INDD} = (e^{\alpha + \beta * T})*\text{GDP}$

Where:

- INDD is industrial distribution sales

- α and β are the regression coefficients from a time series regression of industrial distribution sales over provincial real GDP and a time trend and appropriate binary variables.
- e is exponential base
- T is a time trend variable

The results of the industrial distribution regression forecast, for the remaining segment, are provided in the table below.

Model A1.1	Model A1.1
Estimation Method	OLS
Constant	2.77
Independent Trend Variable	-0.006
Economy Binary Variable	N/A
Adjusted R-sq	0.13
Autocorrelation Range (AR)	< 0.86 or > 1.56
Durbin-Watson	1.75
Autocorrelation Detected?	No

The forecast as produced by estimated regression and the forecasts for oil and gas, mining and wood sectors are provided in the table below.

Table A1.1 Industrial Distribution Forecast before DSM and Rates

Fiscal Year	Regression Forecast Remaining Industrial Distribution (GWh)	Total Distribution Oil and Gas Mining and Wood (GWh)	Total Industrial Distribution Forecast (GWh)
F2012	2,387	1,465	3,852
F2013	2,427	1,706	4,133
F2014	2,472	1,789	4,261
F2015	2,517	1,883	4,400
F2016	2,563	2,032	4,595
F2017	2,617	2,019	4,635
F2018	2,673	2,033	4,706
F2019	2,742	1,999	4,741
F2020	2,797	2,002	4,799
F2021	2,835	2,049	4,884
F2022	2,863	2,053	4,916
F2023	2,889	2,028	4,917

F2024	2,914	2,037	4,950
F2025	2,936	2,045	4,981
F2026	2,962	2,053	5,015
F2027	2,984	2,061	5,045
F2028	3,011	2,068	5,078
F2029	3,041	2,075	5,116
F2030	3,076	2,083	5,158
F2031	3,107	2,088	5,195
F2032	3,134	2,058	5,192

Industrial Transmission

Development of the load forecast for the gas loads is described in Appendix A3.2. The following information is supplemental to the process outline in the forestry and mining sections in Chapter 8.

The methodology used in forecasting the industrial, transmission-voltage consumption incorporates expertise from many sources. Although the forecast is performed on a sector and customer basis, the methodology within each is basically a three step process: 1) creation of consultant reports, 2) internal verification of the reports and 3) compilation and forecast. The consultant reports, used to develop the forestry and mining are produced by independent industry experts. Most of the reports generated provide a long-term economic outlook for that sector and individual production forecasts for each account within that sector.

During the compilation and forecasting process, the following information is compiled and used to produce the individual account forecasts:

- Historical loads, power factors, load factors, production forecasts, energy intensity factors (such as kWh/ unit of output);
- Expansion and expected in-service dates;
- The perceived risk of projects and new loads; and
- Discussions with BC Hydro's Key Account Managers and other contacts.

These are compiled to develop a forecast for each transmission account in the areas of forestry, coal and metal mining.

For the other large transmission industrial sectors including chemicals and the Other category, (which includes government, transportation and some ports), the forecasts are developed on account-by-account basis for the first 11 years of the forecast and then extended by growth rate in GDP and elasticity to GDP in a similar manner to equation (A1.6).

The industrial transmission elasticity of GDP used to develop the forecasts for the chemical and the other remaining category are estimated to 0.38 and 1.09[12] respectively. The results of the regression models that determined this elasticity are provided in the tables below.

Chemical Sector

The following regression model was used to develop elasticity to GDP estimates for the transmission chemical sector.

(A1.9) Sales = $\alpha + \beta*GDP_t + \chi_1*\text{binary variable}$

[12] For continuity between the 2009 and 2010 Load Forecast, the elasticties and regression models, which inform the elasticities, are unchanged between the two forecasts.

Where:

- Sales is the transmission sales to the chemical sector
- GDP is total provincial real output
- The binary variable accounts for loss of a large chemical customer in F2007

Model A1.2	**Model A1.22**
Estimation Method Variable	OLS
Constant	1115.4 (373.1)
Independent X Variable	4.50 (1.6) (X = GDP)
Binary 1	-291.3(60.3)
Adjusted R-sq	0.68
Durbin-Watson (DW)	2.31
Autocorrelation Range (AR)	<1.56 or >0.86
Autocorrelation Detected?	No. DW is outside AR

Transmission Other Sector

Sales to the Other sector in this section refers to: 1) large industrial Other sales as shown in Table 8.2 and 2) non- Oil & Gas commercial transmission customers.

The following regression model was used to develop elasticity to GDP estimates for these customers. The elasticity is 0.49 which was used to develop the long term forecast for this segment of load.

(A1.10) Sales = $\alpha + \beta * GDP_t$

Where:

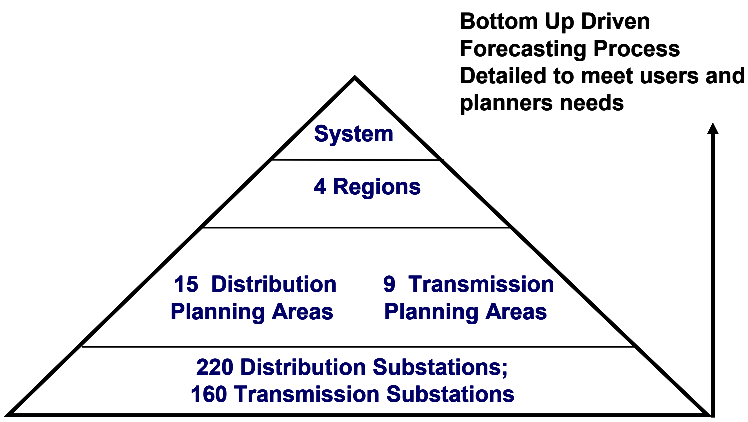
- Sales is sales for the remaining transmission sector
- GDP is total provincial real output

Model A1.3	**Model A1.3**
Estimation Method	OLS
Constant	509.61 (73.10)
Independent X Variable	3.36 (0.49) (X = GDP)
Adjusted R-sq	0.80
Durbin-Watson	1.034
Autocorrelation Range (AR)	<1.34 or >1.01
Autocorrelation Detected?	Neither accept or reject.

A1.3. Peak Demand Forecast Methodology

Figure A1.2 below shows that the bottom-up peak forecast methodology involves several steps for each of the distribution and transmission peak forecasts. The general description of the development stages in system peak forecast is provided following.

Figure A1.2 Peak Demand Forecast Roll-up



The peak demand forecast is built up in three main stages, each incorporating several steps. First stage is the creation of the substation peak in MVA non-coincident[13], second, the four main service region peak forecasts in MW are determined on a region coincident basis and third, the system peak in MW on a system coincident basis.

Stage 1: Substation Peak Demand Forecast

The substation peak forecast is built up in several sub steps: 1 (a) first the weather normalized peak loads by substation/area and short-term forecasts are developed; 1 (b) second the substation peak forecast guidelines are developed from an econometric model for each planning area; 1(c) third an 11-year substation forecast for each substation is created; and, 1 (d) finally the substation and guideline peak forecast are averaged together.

The appropriate equations and description of the sub steps are provided below.

1 (a) Weather Normalized Substation Peak and Short-term Forecast

The equation below is the basis for a linear regression model that estimates the relationship between substation peak demand and temperature:

(A1.11) $$KVA = \alpha + \beta * min$$

Where:

- KVA is the metered peak load; and
- min is the minimum mean temperature for the coldest day during the metered period.

[13] Non-coincident is defined in the glossary.

- α and β are the regression coefficients from a time series regression of peak substation demands on temperatures.

Using the estimated regression coefficients, the weather-normalized peak is then calculated based on the design day temperature for that substation[14]:

(A1.12) $NKVA = \alpha + \beta * designmin$

Where:

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

The first step involves estimating a relationship between substation peak demand and temperature and determining weather normalized substation peak for each substation for the previous winter. This is produced by equation A1.15. The weather normalized substation peak along with historical growth rates of substation peak demands, expected transfers of substation load and expected discrete load additions or closures are used by BC Hydro Distribution planners to prepare a short-term forecast for each substation for the upcoming winter. The first step is completed with an estimate of the weather normalized peak for each substation for the base year or the most recent historical year.

1(b) Distribution Peak Guideline Forecast.

In the section sub step, a distribution substation peak guideline forecast is prepared for 15 planning areas for the first 11 years of the forecast period using the following forecasting and (econometric model) equation:

(A1.18) $SK_{it} = [\alpha_1 SFDHTG + \alpha_2 SFDNON + \alpha_3 MULTHTG + \alpha_4 MULNON + \alpha_5 U35E + \alpha_6 O35E]$

Where:

- SK_{it} is the total substation peak for the i^{th} planning area;
- 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 General under 35 kW;
- O35E is annual energy consumption General over 35 kW;
- 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 rate class Under 35 and Over 35 kW energy consumption.

[14] A regression model using non-linear variables was also used for weather normalization.

The forecasting equation for the distribution peak guideline model is provided in equation A1.18. The guideline forecast provides the expected total substation growth from the base year for each planning area. The drivers of the guideline forecast are based on regional economic information such as housing starts and employment. The guideline forecast is provided to BC Hydro Distribution planners from Market Forecast without adjustments for specific capacity additions or transfers.

1(c) Long-term Substation Forecast

In the third sub-step, an eleven-year substation peak forecast is prepared for each substation using the guidelines, trends in substation growth, forecast load transfers between substations and larger substation load additions. During this step, BC Hydro planners may have additional and information or revised information from field engineers on expected increases or decreases on discrete customer loads as well as operational requirements for substations. This new information, along with the impact of the guideline forecast, may result in a change to the initial short-term forecast for each substation forecast from the first step. The long-term forecasts for each substation are summed up to fifteen planning region totals. These are the total long-term substation forecasts for each planning region.

1(d) Average of Long-term Substation Forecast and Guideline Forecast

The fourth sub step is the calculation of the blending or averaging of the long-term substation forecast and the guideline forecast for each of the 15 planning areas. Prior to the forecasts being averaged, the long-term substation peak forecast and the guideline are aggregated from 15 planning areas into four regional total substation forecasts. These sets substation forecasts (i.e. the long-term substation forecast and the peak guideline forecast) are then averaged together for each of the four service regions based on the following equation:

(A1.13) $$PK_{it} = \Sigma_{it}\ SK_{itGuideline\ +}\ SK_{i\ Substation\ Forecast}$$

Stage 2: Regional Peak Forecast

The regional peak is forecast developed using:

(A1.14) $$RPK_{jt} = \Sigma_j\ [PK_{it}*DCF_j*PF_j + TP_j*TCF_j*PF_j + OP_j*OCF_j]$$

Where:

- DCF is the regional distribution peak coincidence factor;
- PF is the regional power factor for distribution and transmission;
- TP is the transmission peak; this is the aggregate of the transmission account peak forecast in each service region.
- TCF is the transmission coincident factor;
- OP is the other utility peak sales;
- OCF is the other utility coincident factor; and
- PK is the weighted average distribution substation forecast

A transmission peak forecast is prepared for each commercial and industrial transmission account using a bottom-up approach. This involves using the historical peak data, information from Key Account Managers and market information and industry reports.

Stage 3: System Coincident Peak Forecast

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

(A1.15) $SPK = (1 + TL)*\Sigma_j \ RPK_{jt} *SCF_j$

Where:

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

Appendix 2 - Monte Carlo Methods

This Appendix describes the Monte Carlo model that is used to assess the uncertainty associated with BC Hydro's Load Forecast. The description includes a discussion of the methodology, assumptions and parameters of the model.

Load forecasting involves considerable uncertainty. The demand for electricity depends on a large number of factors which fluctuate widely with time and which are difficult to measure. Some of these factors include population, gross domestic product, weather, technology, energy conservation programs (DSM), alternate energy source options, the business climate experienced by major customers and the changing tastes and customers. The challenge of assessing the uncertainty of the load forecast is to quantify the way in which uncertainty in the major causal factors flows through to impact the resultant load.

To quantify load forecast uncertainty, BC Hydro uses a Monte Carlo model and Monte Carlo simulation techniques. The model and simulation analysis proceeds as follows:

- First, several major input variables or causal factors are identified. These are: economic growth (measured by GDP); price of electricity (electricity rates); the effectiveness of DSM, weather (measured by heating degree days) and elasticity of load (with respect to GDP and BC Hydro electricity rates).
- Second, probability distributions are assigned to each input variable and a model is specified that defines the mathematical relationship between the input variable and the output variables.
- Third, a large number of random samples are taken from the input probability distributions. The model is used, with each sample as input, to calculate a large number of simulations of the output variables. These simulations are used to construct probability distributions for the output variables.

The Monte Carlo model calculates the impact of the major causal factors that drive load. The model perturbs the Reference forecast by calculating the impacts for each of the causal factors. The impact factors are random variables. Each of the sectors - Residential, Commercial and Industrial - is perturbed separately, and has separate impact factors, but essentially the same methodology is used for all of them. The model is implemented in Microsoft EXCEL augmented with Palisade Corporation's @RISK software. Energy demand for each sector is computed by the following equation.

(A2.1) $E_t = {}_0E_t\, I_t^P I_t^G I_t^W I_t^U I_t^D$

Here ${}_0E_t$ is base case energy demand, E_t is perturbed energy demand, and the impact factors are identified by their superscripts; P for electricity price (rates), G for GDP, W for weather, U for residual error and D for DSM.

Equation (A2.1) is used to calculate the random variable for energy demand before DSM. A random variable for DSM savings is then calculated and subtracted to give energy after-DSM.

Impact of GDP Uncertainty: In order to assess the impact of uncertainty in future GDP, the base case GDP is perturbed. The base case GDP is denoted by ${}_0G_t$ and the perturbed GDP is denoted by G_t. The perturbed GDP starts off being equal to the base case GDP in the first year. It then grows at a growth rate equal to the base case GDP growth rate (${}_0g_t$) plus a random perturbation growth rate (g_t). This random perturbation is a normally distributed random variable with zero mean and a standard deviation of 1.70%. That is:

(A2.2) $g_t \sim N(0, 1.70\%)$

The perturbed GDP is calculated by:

(A2.3.) $G_t = G_{t-1} [1 + {}_0g_t + g_t]$.

The impact factor for GDP is then given by the following equation:

(A2.4) $I^G_t = \exp(\alpha \ln(G_t / {}_0G_t)) = (G_t / {}_0G_t)^{\alpha}$

where α_0 is the elasticity of load with respect to GDP.

Impact of Price Uncertainty (BC Hydro electricity rates): The calculation of the impact factor for price changes (I^P_t) is treated similarly. A random variable, the perturbed price P_t , is calculated starting from the base case price ${}_0P_t$. The perturbed price starts out being equal to the base case price in the initial year. It then grows at a rate equal to the base case growth rate plus a random perturbation. In the model, the random perturbation has a triangular distribution with parameters (-2.5%, 0, +2.5%). However, unlike the case of GDP, the impact of price change is assumed to take place on a cumulative basis.

Table A2.1 gives the elasticity parameters used in the current Monte Carlo model.

Table A2.1. Elasticity Parameter for Monte Carlo Model

	Mean	Probability Distribution (a,b,c)
Short-term Price Elasticities		
Residential	-0.050	Triangular (-0.075, -0.05, -0.025)
Commercial	-0.050	Triangular (-0.075, -0.05, -0.025)
Industrial	-0.050	Triangular (-0.075, -0.05, -0.025)
Long-term Price Elasticities		
Residential	-0.050	Triangular (-0.075, -0.05, -0.025)
Commercial	-0.050	Triangular (-0.075, -0.05, -0.025)
Industrial	-0.050	Triangular (-0.075, -0.05, -0.025)
GDP Elasticity		
Residential	0.670	Triangular (0.470, 0.670, 0.870)
Commercial	0.780	Triangular (0.580, 0.780, 0.980)
Industrial	0.500	Triangular (0.000, 0.500, 0.100)

In Table A2.1, Triang(a,b,c) refers to a probability distribution known as a triangular distribution because its graph is a triangle. This distribution is zero for values of its random variable less than a or greater than c. It has a maximum (most probable) value at b.

Residual error: This factor incorporates the effect on load of other factors such as changes in technology, consumer taste, household structure, business type, and inter-regional differences. The residual error factor starts out at 1.00 in the base year and grows at a rate that is, in each year, a random variable with the triangular distribution. The impact factor is defined by the following equations:

(A2.5) $I^U_t = I^U_{t-1} (1 + g^U_t) \qquad I^U_0 = 1$

where g^U_t denotes a random variable with a triangular distribution. Again, the @RISK software allows the specification of probability distributions in the model.

Impact of Demand Side Management Uncertainty. The impact of uncertainty in energy savings due to DSM is treated separately from the other impacts. DSM savings are viewed as a random variable (S_t). This variable is subtracted from the previously calculated before DSM energy demand to yield an after-DSM forecast.

(A2.6) $E_t^{after} = E_t^{before} - S_t$

The variability of DSM, as represented by the random variable S_t, was not incorporated into any of the 2011 Forecast uncertainty bands as presented in this document.

Impact of Weather: Variations in weather are an important source of uncertainty in load. The weather impact is most important for the residential and commercial loads, so weather impact is modeled only for these sectors. In British Columbia, the impact of cold weather on residential heating load is the most important weather effect and is modeled using heating degree days (HDD). HDD is an indicator of how much energy is needed to heat housing up to a comfortable temperature. BC Hydro’s summer cooling load is much smaller than the heating load, so the small effect of cooling degree days (CDD) is not modeled.

The weather analysis is based on the last 10 years of daily temperature data at Vancouver International Airport. For every day, the number of heating degree days is calculated by the formula: HDD=max(0, Daily Temperature -18). Then, the annual sum of HDD is calculated for each year.

A standard probability distribution of the Beta type was found to provide the best fit to this data. The Beta distribution has 4 parameters, and is written Beta(a1,a2,Min,Max). Min and max are the maximum and minimum, while a1 and a2 determine the shape of the distribution.

The weather impact factor is calculated by:

(A2.7) $I^W_t = \exp\{ \varepsilon_W \log(HDD_t / 2{,}782) \}$

where ε_W is the elasticity of Residential or Commercial load with respect to HDD. ε_W is estimated judgmentally to be 0.374 for Residential and 0.05 for Commercial. The number 2,782 is the mean value of HDD in the Lower Mainland as calculated from a 10-year rolling historical average.

I^W_t is a random variable as are the other impact factors. However it differs from the other impact factors in that its properties are the same for all years. This is because weather in each year is independent of weather in all other years. Therefore the width of the 80% confidence region for I^W_t does not increase with time.

As mentioned in section 5, the Monte Carlo uncertainty model was expanded to reflect uncertainty in EVs and for overlap in codes and standards between Load Forecast and DSM. This work involved developing distributions for each of these new items and including them in the model.

Appendix 3.1 - Oil and Gas

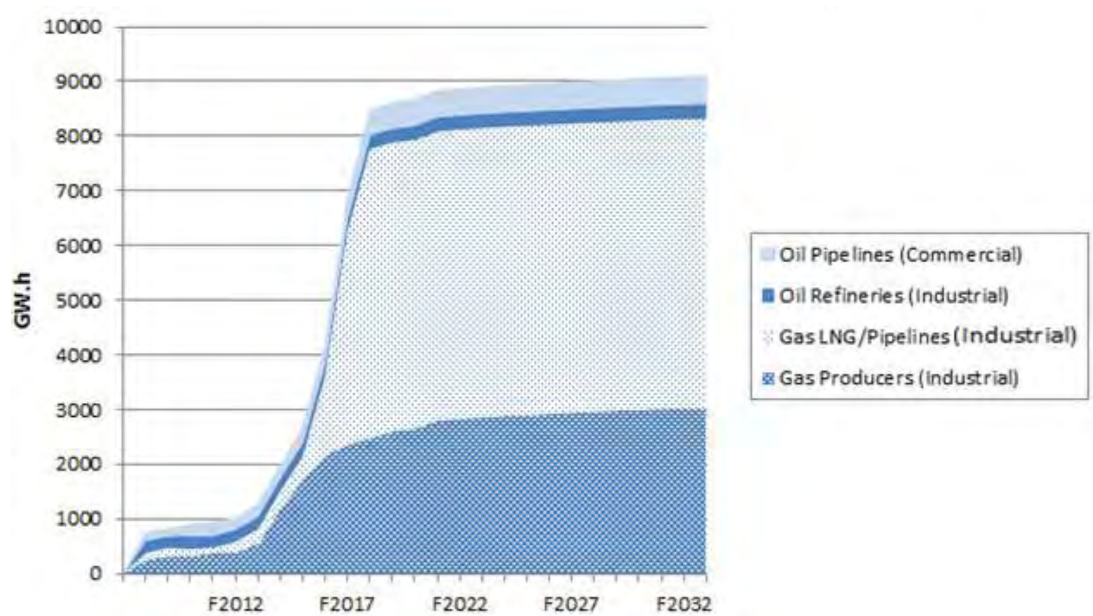
This appendix documents BC Hydro's commercial and industrial oil and gas forecast, and the reasoning behind the forecast for oil and gas sales. As previously indicated, LNG loads are classified in the industrial sector of the 2011 Load Forecast.

The oil and gas sector is categorized into four sub-sectors:

- Oil Pipelines
- Oil Refineries
- Gas LNG/Pipelines
- Gas Producers.

Figure A3.1 illustrates the sub-sector components of the oil and gas load forecast. As shown, significant load growth is expected for the Gas LNG/Pipelines and the Gas Producer sub-sectors.

Figure A3.1: Oil and Gas Sector



Oil and gas customers take electricity service at both transmission and distribution voltages.

The forecast in this section includes the full expected loads for Initial LNG.

A3.1.1 Oil and Gas Overview

Currently, the oil and gas sector makes up five percent of BC Hydro's industrial sales. There are about 70 oil and gas operations located around the province. These operations primarily produce, process and ship petroleum and natural gas. Electricity is mainly used to drive compressors for production and pipeline transportation. In the medium to long term, it is expected that the majority of new gas production will be for export to markets in the U.S. and Asia. The main driver to this sector in the medium to long term is the price for natural gas.

Over the past five years, sales to this sector have been aggressively trending upward, consistent with significant increases in oil and gas production. In F2012, sales are forecast to increase by 9 percent over the previous year. In the short term (F2011-2016), sales are predicted to increase fourfold, primarily due to increased gas production in the Montney Basin and LNG activity on the North Coast.

In the medium term (F2016-F2021), oil and gas sales more than double, largely due to increased activity in the gas production/pipelines and LNG sub-sectors. For the latter 10 years of the forecast period, sales flatten as the level of goods and services provided by oil and customers stabilizes in line with a levelling-off of gas production.

Compared with the 2010 Forecast, the 2011 Forecast is lower in the near term due to the effects of depressed natural gas prices. In the medium to long term, the 2011 Forecast is significantly higher, particularly in the LNG/Pipeline sub-sector, with respect to expectations for LNG on the North Coast. Note that gas producer load for the Horn River has been removed in the 2011 Reference Load Forecast, and is treated as separate scenarios in the analysis for BC Hydro Integrated Resource Plan. Refer to Chapter 9.1 for more details.

A3.1.2 Oil Pipelines Overview

Sales to oil pipelines currently make up 25 percent of BC Hydro's sales to the oil and gas sector. These customers operate pipelines which serve to transport crude oil and petroleum products. Electricity is primarily used in pumping stations and the power sales are correlated to the volume of liquids shipped. Since these customers are providing a service, as opposed to manufacturing a product, they are classified as commercial load.

The main advantage enjoyed by B.C. pipeline operators is that their proximity is conducive to exporting to Asian markets.

Oil Pipelines Outlook

Over the last five years, sales have generally trended up as new pipeline capacity had been added to meet growing demand for exporting crude. In F2012, sales are forecast to decrease by 16 percent compared to previous year, due to short-term operational constraints that will limit shipments and thereby load.

For the first five years of the 2011 Forecast, sales gradually increase as a result of incremental pipeline capacity which is realized by the alleviation of pipeline bottlenecks. From F2016 onward, oil pipelines sales are forecast to grow at a steady pace as anticipated expansion plans are implemented.

Oil Pipelines Drivers and Risk

Drivers:

- Addressing capacity constraints along the pipeline;
- Demand for crude from California and Asia;
- B.C. demand for crude, gasoline and jet fuel, and;
- Economic conditions.

Risk Factors:

- Environmental and social approvals for pipeline expansions and new pipelines.

A3.1.3 Oil Refineries Overview

Sales to oil refineries make up 24 percent of the oil and gas sector. These customers extract, refine and store crude oil and are thus classified as industrial load. A small number of these customers (primarily located in the Lower Mainland) refine crude oil to produce gasoline and jet fuel. They also refine diesel by removing sulphur and provide liquid fuel storage.

Sales in this sub-sector primarily depend on domestic demand for automobiles and air travel. In the future, oil refineries sales are expected to be relatively more dependent on export demand for crude oil and petroleum products. B.C. operators have a competitive advantage due to proximity to petroleum sources, dependability of shipping and receiving, and access to ports.

Oil Refineries Outlook

Over the last five years, sales remained relatively flat in line with local economic conditions. In F2012, sales are forecast to increase slightly due to the expected recovery in gasoline, diesel and aircraft fuel sales from the low levels of the 2008-09 recession.

Over the entire forecast period, sales are expected to increase by 23 percent. Compared to the 2010 Forecast, oil refineries sales in the current forecast are relatively unchanged.

Oil Refineries Drivers and Risk

Drivers

- Demand for gasoline, diesel and jet fuel;
- Oil and gasoline prices; and
- Asian demand.

Risk Factors

- Environmental concerns;
- GHG regulations which might impact refineries; and
- Local and global economic conditions.

A3.1.4 Gas LNG/Pipelines Overview

Sales to this sub-sector compromises 10 percent of the total oil and gas sector sales. Pipeline companies use electricity for compressing gas for shipping and extracting acid gases. LNG operations use electricity primarily for the liquefaction (refrigeration) process which involves chilling and pressurising natural gas. LNG production is a relatively simple process in which the significant majority of work energy is for driving compression in the refrigeration loops, in a process not dissimilar to home-based refrigerators or air conditioning units. BC Hydro has obtained information with respect to LNG demand requirements from potential project proponents and industry publications/studies.

LNG production is a very capital-intensive process; maximizing throughput and utilization are key objectives in LNG plant design. LNG plants therefore are designed to operate continuously, with very little expected intra-day or seasonal variability. Planned maintenance downtime is expected to be minimal, particularly in plants with electrical drives, which is a key attraction of the grid electricity option in plant design.

Gas LNG/Pipelines Outlook

Over the last five years, the load in this sector has been relatively small and highly correlated to North American natural gas prices; however, over, the next 10 years, sales are forecast to significantly grow driven by anticipated LNG requirements in B.C.'s North West and associated pipeline compression. It is expected that the natural gas feedstock for LNG will be primarily supplied from shale gas production in North East B.C. See Appendix A3.2 for more information on northeastern B.C. gas production and electricity demand expectations.

LNG exports to Asia are an attractive market for B.C.'s significant shale gas reserves. North American markets for BC's natural gas are increasingly limited by recent rapid increases in US shale gas production. The price gap between North American gas markets and Asian natural gas markets currently exceeds $10/MMbtu, and is not expected to narrow significantly in the next decade. Canadian producers are increasingly looking to take advantage of this price differential, with a number of LNG export projects being proposed for BC's north Coast.

The 2011 Forecast includes two projects that have both received their export licenses from the National Energy Board (NEB), and have requested electricity service from BC Hydro.

1. **BC LNG Export Cooperative LLC**, which is proposing to build a barge-based liquefaction plant located in Douglas Channel near Kitimat. Preliminary LNG production is expected to be approximately 700,000 tonnes per year. In February, 2012, the NEB granted BC LNG Export Cooperative LLC a license to export 36 million tonnes of LNG at a maximum rate of 1.8 million tonnes per annum (Mtpa). Initial operation is targeted for early 2014. The project could be expanded with additional phases. A final investment decision on the project is expected in 2012.
2. **Kitimat LNG**, a partnership between Apache, EOG and EnCana, is proposing to build an LNG export terminal to be located at Bish Cove on land owned by the Haisla First Nation. The facility would be built in two phases, each totalling approximately 5 Mtpa. The NEB approved a license in October 2011 to export up to 10 Mtpa over 20 years. The currently targeted in-service dates are June 2015 for the first phase and April 2016 for the second. A final investment decision on the project is likely to be made in 2012. A new pipeline, the Pacific Trails Pipeline, has been proposed to transport natural gas from northeastern B.C. to Kitimat.

The 2011 Forecast with Initial LNG, includes the full, undiscounted load for the Kitimat LNG project and the associated pipeline compression and the BC LNG Export Cooperative load on a risk-adjusted basis. BC Hydro assumes that once the plants are fully operational, electricity sales to the two facilities would be constant over the forecast period. The Initial LNG Load is expected to require approximately 5,000 GWh/year of energy for refrigeration and associated pipeline compression load. Since LNG is a very capital intensive undertaking, these operations typically run at very high load factors, with minimal downtime, and little seasonal or intra-day load variations.

Gas LNG/Pipeline Drivers and Risk

Drivers:

- Potential for the conversion of coal-fired generation to less carbon-intensive natural gas-fired generation;
- Asian demand for LNG;
- Possible conversion of some of the Japanese nuclear fleet to gas-fired generation;
- Medium to long term expectations for gas and oil prices;
- BC is the closest of the potential North American LNG sources to major Asian markets;
- Carbon tax and fuel switching for GHG reduction purposes; BC Hydro could service more industry loads at higher carbon prices; and
- Electrification of NE BC unconventional gas production.

Risk factors:

- Social concerns over the footprint of the operations and the exporting/shipping of oil;
- Rate impacts to BC Hydro customers; and
- The speed at which industry customers need electricity supply, and the ability of BC Hydro and the regulatory process to respond to these requests.

A3.1.5 Gas Producers Overview

Sales to this sub-sector currently make up 41 percent of the oil and gas sales. The gas producers are located in northeastern B.C. and primarily use electricity to power their compressors. These customers are categorized as industrial because they produce either conventional gas or shale gas. Although the production of conventional gas in B.C. is expected to remain relatively flat, shale gas production is forecast to grow substantially. BC Hydro anticipates it will be servicing a large portion of shale gas production (see Appendix 3).

Gas Producer Outlook

Over the past five years, sector sales have risen by over 60 percent. In F2012, sales are forecast to remain relatively unchanged due to weak gas prices in the near term, which will dampen B.C. conventional and shale gas production.

In the first five years of the 2011 Forecast, sales are projected to increase nearly six-fold; most of this growth attributable to shale gas development in the Montney Basin (refer to in Appendix 3.2).

During the F2017-22 period, sales growth is forecast to slow and flatten out as new drilling is expected to be directed at maintaining infrastructural efficiency. For the latter 10 years of the forecast, sales are expected to increase marginally with new drilling directed at maintaining gas flows at close to capacity to realize efficiencies.

Compared to the 2010 Forecast, the current forecast for the Gas Producer sub-sector is at similar levels even though sales to Horn River producers have been removed from the 2011 Forecast. Increased sales to shale gas producers in the Montney Basin have mostly offset the 1,200 GWh load previously forecast for the Horn River Basin producers.

Gas Producer Drivers and Risk – See Appendix 3.2

Appendix 3.2 - Shale Gas Producer Forecast – (Montney)

Gas Producer Overview

As indicated in Appendix A3.1, customers serviced by BC Hydro for the production of shale gas are included in BC Hydro's industrial customer sector. This appendix documents BC Hydro's estimates of future load requirements for these shale gas producers.

Shale gas refers to natural gas enclosed in a fine-grained sedimentary formation with low reservoir porosity and low permeability. Although such basins have been uneconomic in the past, new technological advancements such as horizontal drilling and multi-stage hydraulic fracturing have enhanced commercial production of shale gas.

Sales for servicing shale gas production are expected to occur in northeast B.C. BC Hydro's 2010 Load Forecast included expected sales from both the Horn River and Montney shale gas plays; the 2011 Forecast includes sales from only the Montney play and treats potential Horn River sales as a separate scenario for analysis in the Integrated Resource Plan. For more detail on this point, refer to Chapter 9. Regarding the Montney, (in the vicinity of Dawson Creek, see Figure A3.1), sales are expected to increase substantially over the next 10 years, from current low levels, primarily due to regional shale gas development. The Montney Basin shales are believed to contain among the largest untapped reserves of unconventional gas in North America.

Figure A3.1. Map of Montney and Horn River Basins

BC Hydro is closely following a significant number of developments in the Montney area. Below are recent public industry announcements which reflect continued global interest in the Montney Basin:

- The Kitimat LNG is granted a licence to export liquefied natural gas (LNG) from B.C.

- In June 2011, Petronas spends $1.07 billion for a 50 percent interest in three Montney properties from Progress Energy. Petronas is the world's second largest LNG exporter.
- In March 2011, Sasol Ltd. of South Africa paid $1.05 billion for 50 percent of Talisman Energy Inc.'s Cypress A properties in the Montney area. Sasol is a world leader in transforming natural gas into liquid fuels.
- In December 2010, Sasol spends $1.05 billion for a 50 percent stake in Talisman's Farrell Creek properties in the Montney area.

The major advantages for Montney producers are the thickness and richness of the gas reservoirs and their proximity to markets. Montney formations are among the thickest in North America reaching up to 350 meters; which increases the resource base and simplifies drilling. The Montney is also relatively rich in liquids, for which the sale price is more related to an oil-price proxy than a lower gas price. Given foreseeable oil prices, this is a major incentive to production economics. Montney gas is relatively free of contaminants such as CO_2 and sulphur compounds. In terms of infrastructure (roads, personnel, servicing industry) the Montney region is well developed, relative to the more remote Horn River. Finally, Montney gas production may form a significant basis for LNG exports from the BC west coast, which is the closest potential export point from North America to Asian load centers. These advantages serve as primary drivers for investment and drilling activity in the Montney Basin.

Gas Producer Outlook

Sales to gas producers are forecast to continue to rise as it is expected that producers will continue with drilling and completions programs. Drilling in F2012 will likely be motivated less by gas prices and more by high oil prices, existing supply contracts (where gas prices were previously locked in at higher levels) and drilling obligations for the maintenance of land leases.

In the short term (F2011-F2016), sales are forecast to substantially increase, driven mainly from expectations of new drilling operations. These projections are based on customer requests for service and from BC Hydro's forecasting model (see next section for further details).

In the medium term (F2016-F2021), sales are forecast to continue to rise but at a slower pace. It is expected that gas production will continue to expand and that the number of sites serviced by BC Hydro will increase. By the end of F2021, gas production is expected to reach 4,300 million cubic feet per day (MMcf/d) in the Montney Basin. Although this projection is 37 percent higher than last year's gas production forecast, it is in line with third party projections. The primary reason for the increase is that BC Hydro has significantly revised upward its forecast for the northwestern part of the Montney Basin. This area has experienced a great deal of investor activity as of late and is reportedly very rich in valuable natural gas liquids.

For the last 10 years of the forecast, sales peak and then level-off. This differs from the 2010 Load Forecast in which gas production and electricity sales in this timeframe was expected to decline. This change arises from BC Hydro's view that the life of regional shale gas wells will be longer than in the previous forecast, resulting in relatively higher gas recovery. Sales in the 2011 Forecast are not projected to begin an overall decline until F2033.

Compared to the 2010 Forecast, as driven by updated gas production expectations, the 2011 Forecast for Montney gas producers is lower in the initial years but becomes considerably higher afterwards. This is shown in Table A3.1 below. By F2015, the current sales forecast is 12 percent higher, in F2020 the current forecast is 28 percent higher and in F2030 the current forecast is 44 percent higher. This can be attributed to a number of factors including: (i) BC Hydro has experienced increased inquires for electricity service, (ii) industry experts have increased their gas production forecasts; and (iii) additional industry capital is being committed towards gas production and export infrastructure.

Table A3.1 Montney Gas Production and Sales Forecasts – Before DSM and Rate Impacts

	Integrated Area (Peace Region)			
	Total Gas production		Electrical Load	
	MMcf/day		GWh	
Forecast	**2011**	**2010**	**2011**	**2010**
F2012	1,044	1,139	198	448
F2013	1,382	1,471	391	635
F2014	1,800	1,883	1,068	1,123
F2015	2,332	2,213	1,637	1,463
F2016	2,859	2,474	2,136	1,783
F2017	3,428	2,698	2,323	1,939
F2018	3,792	2,879	2,477	2,014
F2019	4,029	3,014	2,610	2,063
F2020	4,204	3,135	2,681	2,101
F2021	4,345	3,205	2,845	2,204
F2022	4,463	3,256	2,889	2,249
F2023	4,563	3,288	2,922	2,294
F2024	4,646	3,302	2,952	2,326
F2025	4,714	3,312	2,979	2,359
F2026	4,768	3,314	3,005	2,390
F2027	4,808	3,297	3,030	2,419
F2028	4,836	3,263	3,055	2,331
F2029	4,853	3,213	3,079	2,230
F2030	4,858	3,147	3,101	2,158

Montney Shale Gas – Drivers and Risk

Drivers

- Natural gas prices in North America – a high price stimulates load demand because it makes it more profitable to produce shale gas;
- Price of oil – a high price elevates load demand. The Montney Basin is one of a limited number of North American gas plays that is rich in natural gas liquids; since liquids prices closely follow oil prices, a high oil price stimulates production in liquids-rich gas plays;
- LNG port development in B.C. – LNG export development would significantly increase demand for natural gas from BC.; and
- Fracturing technology – evolving hydraulic fracturing technology produces proportionally greater benefits to the large rich shale gas plays such as the Montney.

Risk Factors

- Greenhouse gas regulation – GHG emission reduction targets in B.C. and the U.S.;

- Regulation of formation fracturing operations – the U.S. Environmental Protection Agency is reviewing these operations near metropolitan areas in the U.S., which may lead to constrained shale gas production;
- Other new N. American gas supply – which includes coal bed methane and other shale gas plays on the continent and associated gas in Alaska;
- New global gas supplies. Russia, China and Australia have shale gas potential. However, shale gas development in Asia is significantly behind that in N. America. Nevertheless, LNG exports from Russia and Australia will likely provide competition to N. American LNG. And domestic Asian shale gas production could lower demand for N. American LNG; and
- Montney development and operational costs – the Montney is relatively far from the major gas markets, whether in N. America, or potential LNG terminals. These large distances require new pipelines, and higher shipping tariffs and fuel gas costs than LNG that is closer to load (such as in the US Eastern seaboard).

Shale Gas Forecast Methodology

BC Hydro employs two approaches to develop the forecast, referred to as the bottom-up and top-down methodologies. The bottom-up forecast is based on customer-specific information and analysis and serves as BC Hydro's official load forecast. The top-down forecast is a macro forecast that is used to guide and confirm the bottom-up forecast.

Bottom-up Forecast

The 2011 gas producer load forecast is generated using a bottom-up approach; it also includes an iterative exercise with the top-down forecast. The bottom-up forecast originates from a compilation of current and expected customer load requests. In arriving at an 'expected' or most likely net customer service requirement, each customer request is evaluated, shaped and discounted based on information from various sources internal and external to BC Hydro. External factors come from a number of areas such as industry, producer publications and the top-down forecast, as explained below.

Top-down Forecast

The top-down forecast uses macro information to arrive at the Montney load forecast. In doing so, it serves as a guide to check and improve the accuracy of the bottom-up forecast.

As discussed below, the top-down forecast is derived by creating and then multiplying three data sets, as follows:

Top-down Forecast = Production x Intensity x Service Percent

<u>Production Table</u>

The production table is a forecast of annual natural gas volume over the life of the gas play. The production table is constructed using a forecast of two drivers – wells drilled (per year) and a well production profile. These parameters are determined by setting the expected well life, initial production level and well decline rate.

The production table results need to be consistent with expectations for total gas recovered, total wells drilled, average well production, planned pipeline capacities, gas price forecasts and full-cycle economic costs for B.C. gas plays and competing plays in North America. To ensure that the results are reasonable, BC Hydro conducts a comparative analysis with those of industry associations, producers, pipeline companies, and government and industry experts.

For the Montney Basin, the major drivers for the production table are shown in Table A3.2 below:

Table A3.2 Major Driver Characteristics and Production Assumptions

Well life	25 years
Initial well production level first month	5.25 MMcf/day
Well decline rate - month 1 (annualized)	10.3%
Well decline rate - month 60	0.60%
Well decline rate - month 240	0.60%
Drilling pattern	Assumed to be uniform throughout the year
Total recoverable gas	64 trillion cubic feet
Wells drilled	11,000
Average production per well	5.2 billion cubic feet (Bcf)
Peak production year	F2030
Peak production year volume	4.9 Bcf/day
Number of years of drilling	50
Number of years in modelling	70 years

Figure A3.2 shows BC Hydro's shale gas production forecast for the Montney Basin (bold line marked with x's). This is used to produce the Base Case Forecast. Also shown are production forecasts from other third parties.

Figure A3.2 Montney Shale Gas Production Forecast

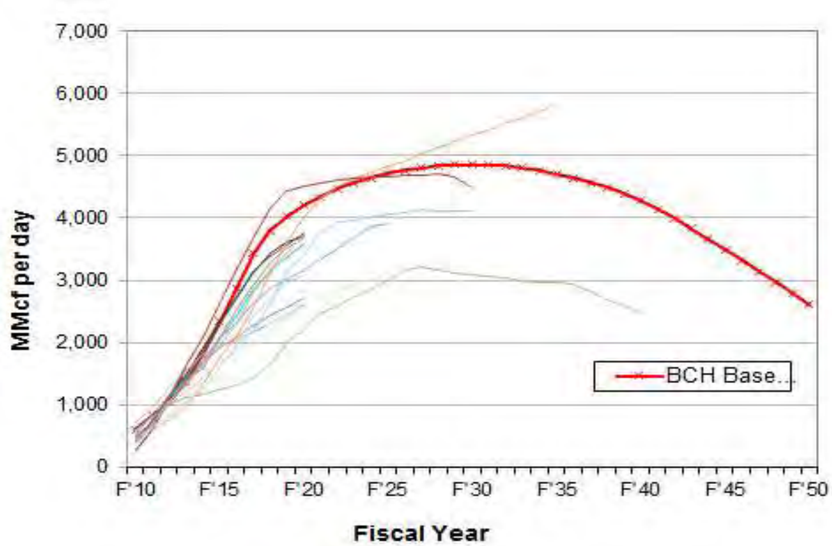
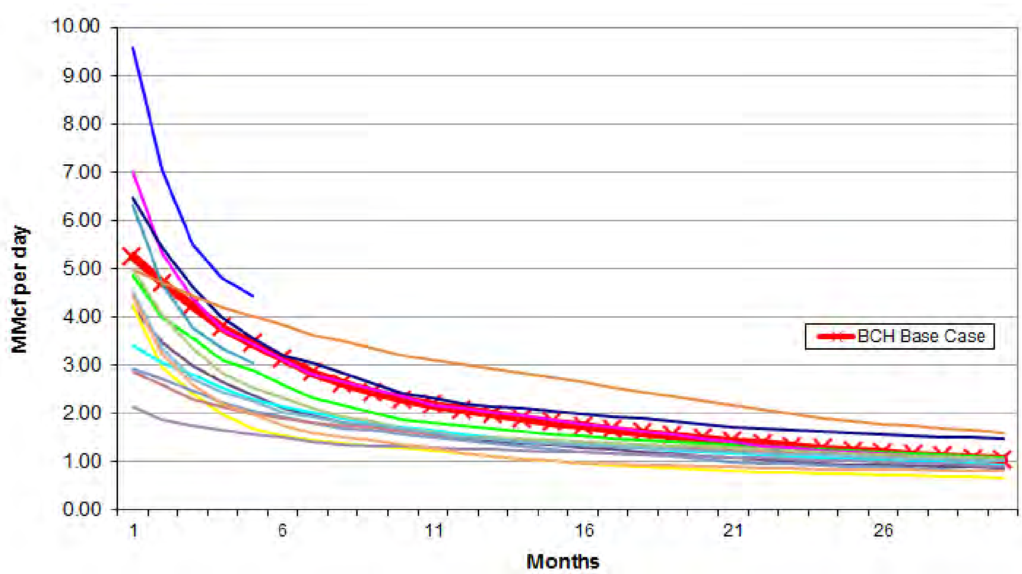


Figure A3.3 shows the production profile of a typical well in BC Hydro's model and typical well projections from other sources. As with Figure A3.2, source of the other well curves is blanked out in the chart legend for the purposes of confidentiality.

Figure A3.3 Well Production Curve (with other industry projections)



Multiplying the production table by an intensity level yields the energy needed to produce the gas over the next 60 years. This represents the total energy required to bring gas to the high pressure pipeline grid. A percentage of this is assumed to be serviced by BC Hydro (see below).

<u>Intensity Table</u>

The intensity factor is multiplied against gas production estimates to determine the total energy requirement needed to produce the gas. Intensity times production equals total energy needed, as shown in the equation below:

Intensity (MW/MMcf/day) x Production (MMcf/day) = Power Requirement (MW)

where: MW is megawatts of power consumption and
MMcf/day is million cubic feet of gas per day

BC Hydro's intensity rate is a compilation of two approaches: (a) determining the energy requirements of the major processes within a typical plant, and (b) conducting an industry survey. BC Hydro's calculation factors for estimating the typical plant requirement are detailed below:

Compression	0.10 MW/MMcf/d
+ Processing	0.010 MW/MMcf/d
+ Additional Compression	0.001 to 0.01 MW/MMcf/d
= Total	0.111 to 0.120 MW/MMcf/d

As shown above, the total intensity rate range is 0.111 to 0.120 MW/MMcf/d. This is comparable to industry information indicating a range of 0.08 to 0.14 MW/MMcf/day, with a number of estimates clustered around a value of 0.120.

The compression intensity of 0.10 MW/MMcf represents the energy needed to move the gas from the wellhead, through the field gathering system and into a centralized processing facility (where electricity is also used in the processing process, (which includes the removal of gas liquids) and then eventually to the high-pressure, downstream pipeline. This calculation assumes:

- Well-head pressures of 140 to 240 Psi
- Mainline pipe pressure of 900 to 1,440 Psi
- 2 or 3 stages of compression.

The processing intensity of 0.010 MW/MMcf/d is for ancillary electric loads for removing water and acid gases. In the Montney, gas can be processed at the processing facility since gathering pressures are low and the gas generally is only slightly sour. This estimate assumes:

- Only a small portion of gas in the Montney is sour (in the regions closest to the Alberta border), per industry sources; and
- The water content of the gas is low and much of the gas meets pipeline specifications of about four pounds of water per MMcf of gas.

The additional compression intensity of 0.001 to 0.01 MW/MMcf/d is BC Hydro's estimate for additional load that is expected to be required to move gas from the processing facility to the downstream pipeline. As the Montney play develops, additional pipeline compression is expected to be required to move gas downstream.

Other assumptions:

- Hydraulic fracturing operations would not require service from BC Hydro; these operations are of a short duration and generally in remote locations;
- Water recycling loads would not be material;
- Downstream pipeline loads would not be served by BC Hydro.

Service Percent Table

The service percent is the proportion of total energy to be provided by BC Hydro's electricity service. A number of factors have been considered by BC Hydro in arriving at this figure – namely, evolving trends for the areas, engineering calculations and economic analysis, discussion with BC Hydro staff who work directly with the new customers and industry surveys conducted by BC Hydro. For the Montney Basin, the forecast is divided into five areas with the following service percentages:

- Dawson Creek: 40% ramping up to 95% over the forecast horizon
- Groundbirch: 15% ramping up to 95%
- Chetwynd: 20% ramping up to 85%
- Fox/Fort St. John: 20% ramping up to 70%
- G.M. Shrum: 20% ramping up to 37%.

Appendix 4 - Electric Vehicles (EVs)

Overview

At present there is significant interest in EVs. Although there is much uncertainty about when and if they will achieve large market penetration, EVs have many attractive features, particularly with respect to emissions and fuel costs. There could be significant numbers of EVs on the B.C. highways, provided charging infrastructure issues are resolved. Since 2010, BC Hydro's long-term forecast has included the impact of EVs. Some of the reasons for introducing EV into the load forecast are:

- BC Hydro's customers are showing greater interest in using EVs.
- Most major automobile manufacturers have announced plans to produce and sell EVs in the next few years. A limited number of models are now under commercial production.
- BC Hydro is working collaboratively with various organizations on issues such as how to prepare the grid infrastructure for EVs, particularly with respect to the management of peak loads from fast charging.

EVs have a large fuel cost advantage over gasoline vehicles. EVs are about four times as efficient in converting fuel to motion. This efficiency results in much lower fuel costs for EVs under all reasonably anticipated ranges of electricity versus gasoline prices. Local environmental benefits are significant for EVs, in particular due to reductions in carbon dioxide and other tailpipe emissions. The amount of these reductions depends on how the electricity used in the EV is produced. Generation by natural gas can reduce net CO_2 emissions by more than 50%, while the use of non-fossil fuels such as hydro, nuclear, wind and solar could reduce emissions to close to zero. Regardless of the generation mix, EVs have negligible emissions in the location where they are used.

There are key barriers to the rapid adoption of EVs via large scale production. For example some production EVs have a range that is too small. While the average daily commute in the U.S. and Canada is less than 60km, most car owners want the option of taking an occasional trip of several hundred kilometres or more. The purchase price of EVs is higher than comparable gasoline vehicles; the difference is typically in the range of $15,000 and $20,000, largely due to the cost of batteries. This is a key barrier to the widespread adoption of EVs. In addition, a system of rapid charging facilities will be needed at key locations such as shopping centers, city centers and major highways. An infrastructure of repair facilities will also be required. Electric cars will also have to prove their reliability. Design, style and size of EVs will have to be acceptable to the public.

The development of improved battery technology is critical to EV introduction; automobile manufacturers must take the risks and make the very large investments that will be needed to move from announcements and small scale pilots to the mass production of EVs.

The next sections discuss the development of the energy and peak demand impacts of EVs included in the 2011 Load Forecast.

EV Impacts on Energy Requirements

For the 2011 load forecast, the energy impacts from EVs in the Reference forecast and high scenario are unchanged from those included in the 2010 Load Forecast.

The load impact of EVs consists of a reference case and a high case scenario. The forecast of EV impact on the load stems from a model that takes into account many variables including: population and vehicle growth, rate forecasts, gasoline and electricity price forecasts, and efficiencies for both electric and gasoline cars. The model produces a forecast of the number of EVs and their annual energy consumption.

The EV reference case is conservative outlook for the development of the EVs and resulting load impacts. The reference case includes the following key assumptions:

- A constant energy efficiency of 25 miles per gallon for gasoline vehicles and 0.20 KWh per km for EVs;
- No specific new policy initiatives for encouraging EVs. The High EV adoption case does include an assumption regarding a purchase incentive;
- The supply of EVs is constrained in the first 10 years of the forecast. Auto manufacturers will need several years to significantly increase mass production once demand for EVs increases. In addition the market place will need time to evolve in areas of battery production, retrofitting current factories or creating new facilities dedicated to EV manufacturing.

The EV adoption rate in the model is driven primarily by economics. Competition between the fuel cost advantage of EVs and the lower capital cost of gasoline cars drives consumer choice. Capital cost for EVs is $42,000 compared with $25,000 for comparable gasoline cars. The penetration rate of EVs is very small in the first 5 years but increases rapidly from 2020 due to the relaxation of assumed manufacturer supply constraints. As shown Figure A4.1, the percentage of all light duty vehicles on the road (Stock Share) increases from 0.3% in 2017 to 16% in 2031 and to 29% in 2041. The number of B.C. EVs increases from approximately 10,000 in 2017 to over half a million in 2031 to over a million in 2041.

Figure A4.1 Stock Share of Electric Vehicles in BC

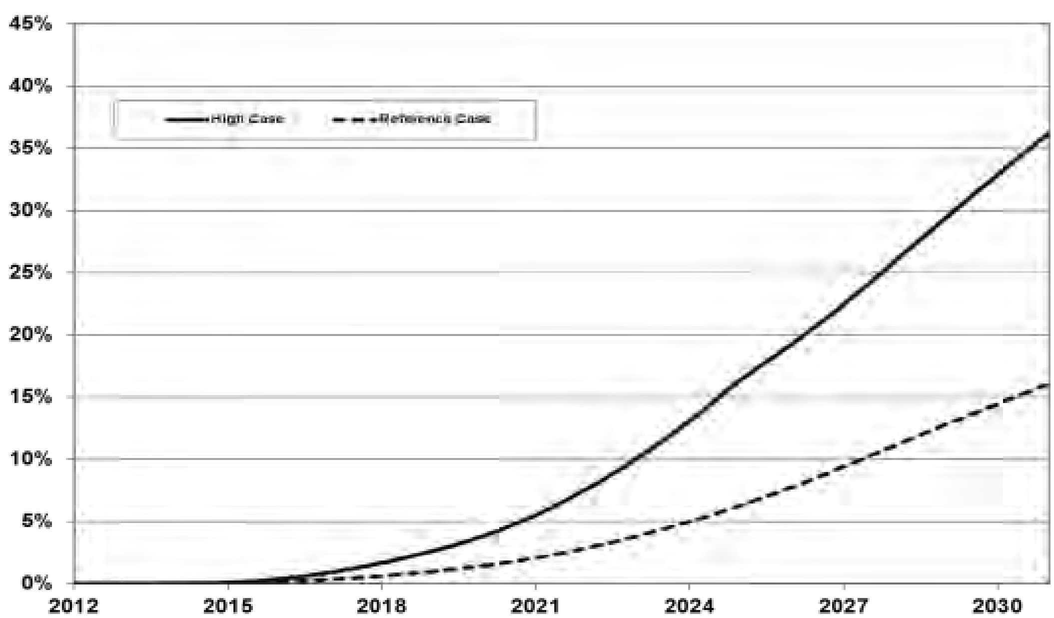


Table A4.1 EV Residential and Commercial Load (GWh) and (MW)

	A	B	C=A+B	D
	2011 Forecast - Residential EV Load	**2011 Forecast - Commercial EV Load**	**Total EV Load Reference Case**	**Total EV Peak Load Reference Case**
Fiscal Year	(GWh)	(GWh)	(GWh)	(MW)
F2012	-	-	-	0
F2013	1	-	1	0
F2014	2	1	2	1
F2015	3	1	4	1
F2016	12	4	16	4
F2017	29	10	38	10
F2018	53	18	71	19
F2019	86	29	115	31
F2020	128	43	171	46
F2021	186	62	248	67
F2022	262	87	349	94
F2023	355	118	473	81
F2024	465	155	620	112
F2025	592	197	790	147
F2026	738	246	984	186
F2027	902	301	1,202	228
F2028	1,075	358	1,433	270
F2029	1,248	416	1,664	313
F2030	1,420	473	1,894	358
F2031	1,590	530	2,120	404
F2032	1,757	586	2,342	451

Note:

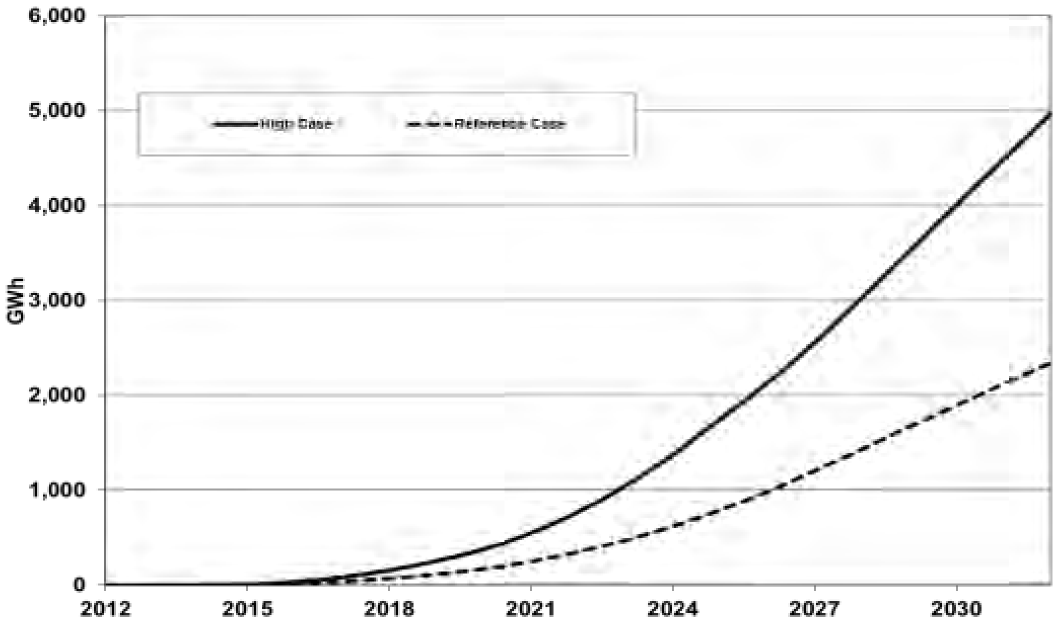
1. The values in the table above do not include any rate impacts.

Table A4.1 shows the residential EV load and commercial EV load and the total EV load included in the 2011 reference load forecast.

In the High Case scenario, a series of potential actions are anticipated to facilitate the introduction of EVs, in particular that the purchase price of EVs is reduced by a $5,000 government purchase price subsidy, which is assume to persist throughout the forecast horizon. Similarly, there is an additional rebate of $2,000 towards home charging equipment costs. Finally, the practical driving range of EVs increase over time based on the assumption of a significant number of EV charging stations in BC Hydro's service territory. As seen in Figures A4.1 and A4.2, these measures and initiatives significantly increase the adoption rate of EVs.

The annual energy load due to EVs is forecast for both scenarios; Figure A4.2 illustrates both load scenarios before rate impacts.

Figure A4.2 EV Load Forecast



Risks and Uncertainties

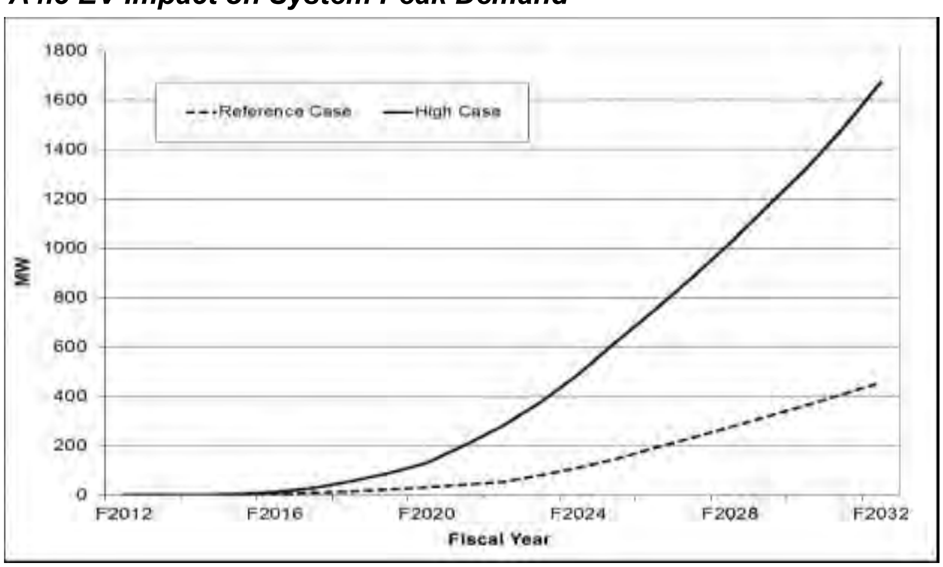
The EV forecast is very uncertain; changes in any of the key model variables would lead to significant modifications to the forecasts. Adoption of EVs will depend upon many variables such as advances in technology, especially battery and fast-charging technologies, consumer acceptance, the availability of charging infrastructure and continued government support and initiatives.

EV Impact on Peak Demand

Overview:

Figure A4.3 shows the approximate peak EV impact included in the 2011 Reference distribution peak forecast.

Figure A4.3 EV Impact on System Peak Demand



Comparison to 2010 Forecast

The impact of EVs on BC Hydro peak load in the reference case is 10 MW in F2017 and approximately 410 MW in F2031, which is about 230 MW lower relative to the peak impact in the 2010 Load Forecast. In the 2010 Load Forecast, a custom EV peak model was developed within BC Hydro and used to estimate the peak impacts of EVs. This model was not updated in 2011, so an alternative approach was taken. Specifically, the peak impact of EVs over the second 10-year period of the load forecast (and beyond) was assumed to follow the energy load growth rates are used to develop the distribution peak forecast over this period. The peak demand impacts in the High Case were assumed to be unchanged relative to the 2010 Load Forecast, as were the energy requirements assumptions in the Reference Case.

Appendix 5 - Codes and Standards Overlap with DSM

Codes and standards are minimum end-use efficiency requirements that come into effect in a jurisdiction, and that are enabled by legislation or by regulation of manufacturers. U.S based codes and standards are reflected in the average stock efficiency forecast of residential and commercial end uses of electricity produced by the U.S. Department of Energy's Energy Information Administration (EIA). This EIA efficiency forecast is one of the main drivers of the residential and small commercial end-use models that are used to produce the BC Hydro load forecast before incremental Demand Side Management (DSM) savings. BC Hydro's DSM plan also considers savings that can be achieved from B.C. and Canadian Federal codes and standards that target similar end uses as those represented in the EIA efficiency forecast data. As such, there is a potential for inconsistency in codes and standards planning assumptions between the before DSM and rate impacts Load Forecast and the DSM plan.

Areas of Overlap between EIA and DSM Plan Codes and Standards

The EIA assumes that no new legislation or regulations fostering efficiency improvements beyond those currently embodied in law or government programs will take place over the forecast horizon. As such, the end-use efficiency levels assumed in the EIA forecast only consider the targeted efficiency level from the mostly recently passed legislation or regulations. These efficiency level assumptions are documented by the EIA[15]. BC Hydro reviewed the EIA baseline codes and standards efficiency assumptions and compared it to the codes and standards baseline efficiency assumptions as of December 2011. Using this information, BC Hydro was able to determine where there were overlaps in assumptions between the before DSM and rate impacts forecast and the savings from codes and standards. The areas are shown as follows:

Areas of Overlap between EIA Codes and Standards and BC Hydro DSM Plan[16]	
Residential Sector	Lighting, ceiling fans, dishwashers, stand-by power, set top boxes, TVs, freezers, refrigerators and external power supply
Commercial Sector	Lighting, large clothes washers, traffic lights, large refrigerators, air conditioning, packaged terminal air conditioning, dry transformers, and building code.

Estimates of Overlap between EIA Codes and Standards and the DSM Savings from Codes and Standards

The method used in the 2011 Load Forecast to estimate the impact of codes and standards double counting was to rely upon on the estimated codes and standard savings included in DSM plan[17]. For lighting codes and standards double counting, a process of freezing the input efficiency levels to the 2007 lighting efficiency forecast was used. This

[15] Appendix A of the EIA Annual Energy Outlook 2009 documents titled "Handling of Federal and Selected State Legislation and Regulation in the Annual Energy Outlook". In addition information from EIA 2011 Annual Energy Outlook and website www.appliance-standards.org was used to develop estimates of the overlap.
[16] Note that in all of the end uses listed, the EIA provides an efficiency forecast for lighting separately. The other end uses listed above are reflected in the "other" category and the EIA provides an efficiency forecast for other category as a total group.
[17] The codes and standards savings forecast included in BC Hydro's latest updated DSM plan was used to inform estimates of the overlap in codes and standards.

method for lighting was chosen to provide consistency with 2010 Load Forecasts that had already identified a double counting issue with lighting codes and standards.

BC Hydro used 50 percent of the DSM savings estimates of the various codes and standards which overlapped with the EIA. The main reasons for using half of the DSM estimates were:

- There is the potential for some error in the double counting impact estimating process because there is uncertainty as to compliance levels for codes and standards.

- At the time the load forecast was developed BC Hydro was exploring 5 future DSM options. As such the overlap associated with the double counted end-uses might vary pending which DSM option would be used for planning purposes.

Table A5.1 and Table A5.2 below show the estimates of the overlap between the residential and commercial sector energy forecasts for the overlap areas. Table A5.3 below shows the BC Hydro's distribution peak forecast with an estimate of the overlap between codes and standards over the long-term[18].

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[18] The impact of overlap in code of standards was included in the overall growth rates of the energy forecast in the second 10 years of the forecast. These energy growth rates are used to develop the distribution peak forecast over this period.

Table A5.1 Residential Energy Forecast (before DSM and rate impacts) with Overlap for Codes and Standards

	A	B	C=A+B
Fiscal Year	**2011 Forecast Residential Sales (GWh)**	**Adjustment for Overlap in Residential Code and Standards (GWh)**	**Residential Sales Forecast with Codes and Standards Overlap (GWh)[1]**
F2012	18,214	28	18,242
F2013	18,641	71	18,713
F2014	19,003	110	19,113
F2015	19,353	125	19,478
F2016	19,731	148	19,878
F2017	20,094	199	20,293
F2018	20,492	238	20,730
F2019	20,915	268	21,183
F2020	21,360	290	21,649
F2021	21,739	309	22,048
F2022	22,110	325	22,434
F2023	22,470	338	22,808
F2024	22,846	359	23,205
F2025	23,158	371	23,528
F2026	23,481	384	23,865
F2027	23,814	390	24,205
F2028	24,186	405	24,591
F2029	24,508	420	24,927
F2030	24,848	433	25,281
F2031	25,197	444	25,641
F2032	25,575	457	26,032

Notes:

1. Note the values in column C do not include any adjustments for the impact of EVs and rate impacts.

Table A5.2 Commercial Energy Forecast (before DSM and rate impacts) with Overlap for Codes and Standards

	A	B	C=A+B
Fiscal Year	**2011 Forecast Commercial Distribution Sales (GWh)**	**Adjustment for Overlap in Commercial Code and Standards (GWh)**	**Commercial Sales Forecast with Codes and Standards Overlap (GWh)** [1]
F2012	14,568	16	14,585
F2013	14,911	29	14,941
F2014	15,218	37	15,254
F2015	15,528	45	15,573
F2016	15,877	55	15,932
F2017	16,212	72	16,284
F2018	16,559	86	16,645
F2019	16,931	100	17,030
F2020	17,283	113	17,397
F2021	17,562	128	17,690
F2022	17,837	141	17,978
F2023	18,095	152	18,248
F2024	18,360	167	18,528
F2025	18,579	179	18,757
F2026	18,840	194	19,033
F2027	19,143	206	19,349
F2028	19,522	223	19,745
F2029	19,901	239	20,140
F2030	20,333	256	20,588
F2031	20,773	271	21,045
F2032	21,231	289	21,521

Notes:
1. Note the values in column C do not include any adjustments for the impact of EVs and rate impacts.

Table A5.3 Distribution Peak Forecast with Overlap for Codes and Standards

	A	B	C=A+B
Fiscal Year	**2011 Forecast Distribution Peak (MW)**	**Adjustment for Overlap in Code and Standards (MW)**	**Peak Forecast with Codes and Standards Overlap (MW)** [1]
F2012	7,888	10	7,898
F2013	8,082	25	8,107
F2014	8,279	37	8,316
F2015	8,456	43	8,499
F2016	8,637	48	8,685
F2017	8,785	60	8,845
F2018	8,939	67	9,006
F2019	9,090	72	9,162
F2020	9,243	74	9,317
F2021	9,381	74	9,455
F2022	9,503	71	9,574
F2023	9,638	85	9,723
F2024	9,776	96	9,872
F2025	9,917	104	10,020
F2026	10,060	105	10,165
F2027	10,205	109	10,314
F2028	10,353	114	10,467
F2029	10,503	120	10,623
F2030	10,657	126	10,783
F2031	10,813	130	10,943
F2032	10,971	138	11,109

Notes:

1. Note the values in column C do not include any adjustments for the impact of EVs and rate impacts.

Appendix 6 - Forecast Tables

Table A6.1 shows the Regional coincident peak (MW) forecast for distribution before DSM with rate impacts (Excluding Initial LNG Load)

Table A6.2 shows the Regional coincident peak (MW) forecast for transmission before DSM with rate impacts (Excluding Initial LNG Load)

Table A6.3 shows the Domestic and Regional peak forecast before DSM with rate impacts (Excluding Initial LNG Load)

Table A6.4 summarizes BC Hydro's 2011 Reference Load Forecast before DSM with rate impacts (Excluding Initial LNG load)

Table A6.5 summarizes BC Hydro's 2011 Reference Load Forecast before DSM with rate impacts (Including Initial LNG load)

Table A6.1 Regional Coincident Distribution Peaks Before DSM with Rate Impacts (Excluding Initial LNG Load) (MW)

Fiscal Year	Coincident Peak (MW)			
	Lower Mainland	**Vancouver Island**	**South Interior**	**Northern Region**
Actual				
F2011	4,360	1,935	979	688
Weather-Normalized Actual				
F2011	4,562	1,847	1,001	707
Forecast (Weather-Normalized)				
F2012	4,596	1,861	1,022	751
F2013	4,709	1,898	1,038	795
F2014	4,858	1,913	1,061	820
F2015	4,966	1,923	1,082	850
F2016	5,070	1,936	1,095	894
F2017	5,172	1,955	1,105	911
F2018	5,275	1,972	1,122	924
F2019	5,380	1,992	1,130	936
F2020	5,483	2,009	1,141	950
F2021	5,576	2,027	1,152	955
F2022	5,680	2,048	1,155	960
F2023	5,821	2,073	1,173	964
F2024	5,960	2,095	1,189	968
F2025	6,102	2,118	1,206	971
F2026	6,248	2,141	1,223	975
F2027	6,397	2,164	1,240	978
F2028	6,550	2,188	1,257	982
F2029	6,707	2,212	1,275	985
F2030	6,867	2,236	1,293	988
F2031	7,031	2,260	1,311	992
F2032	7,199	2,285	1,330	995
5 years: F2011 to F2016	2.1%	1.0%	1.8%	4.8%
11 years: F2011 to F2022	2.0%	0.9%	1.3%	2.8%
21 years: F2011 to F2032	2.2%	1.0%	1.4%	1.6%

Notes:
1. Growth rates based on weather normalized actual peak.
2. Vancouver Island peak values include Gulf Island peak demand.

Table A6.2 Regional Coincident Transmission Peaks Before DSM with Rate Impacts (Excluding Initial LNG Load) (MW)

Fiscal Year	Coincident Peak (MW)			
	Lower Mainland	**Vancouver Island**	**South Interior**	**Northern Region**
Actual				
F2011	359	198	226	653
Forecast				
F2012	430	257	297	603
F2013	452	265	341	679
F2014	457	297	348	889
F2015	470	294	378	997
F2016	462	295	406	1,099
F2017	465	294	414	1,181
F2018	467	231	418	1,247
F2019	485	222	421	1,262
F2020	494	221	420	1,288
F2021	494	221	420	1,284
F2022	495	221	420	1,287
F2023	498	221	410	1,284
F2024	500	221	409	1,289
F2025	502	221	409	1,291
F2026	507	212	355	1,270
F2027	508	212	339	1,217
F2028	510	211	341	1,219
F2029	512	211	361	1,193
F2030	514	211	363	1,210
F2031	517	211	366	1,257
F2032	519	211	368	1,259
5 years: F2011 to F2016	5.2%	8.3%	12.4%	11.0%
11 years: F2011 to F2022	3.0%	1.0%	5.8%	6.4%
21 years: F2011 to F2032	1.8%	0.3%	2.4%	3.2%

Table A6.3 Domestic System and Regional Peak Forecast Before DSM with Rate Impacts (Excluding Initial LNG Load) (MW)

	Lower Mainland (MW)	Vancouver Island (MW)	South Interior (MW)	Northern Region (MW)	Domestic System (MW)	Vancouver Island with Transmission Losses (MW)
Actual						
F2011	4,950	2,133	1,335	1,341	9,915	2,228
Weather-Normalized Actual						
F2011	5,152	2,044	1,358	1,361	10,047	2,136
Forecast (Weather Normalized)						
F2012	5,243	2,118	1,520	1,354	10,308	2,213
F2013	5,379	2,163	1,579	1,474	10,684	2,259
F2014	5,535	2,210	1,609	1,709	11,162	2,309
F2015	5,657	2,217	1,659	1,847	11,490	2,316
F2016	5,753	2,231	1,701	1,993	11,797	2,330
F2017	5,861	2,249	1,719	2,092	12,047	2,349
F2018	5,967	2,203	1,740	2,172	12,215	2,301
F2019	6,091	2,214	1,751	2,199	12,394	2,312
F2020	6,204	2,230	1,762	2,238	12,580	2,329
F2021	6,298	2,248	1,772	2,239	12,710	2,348
F2022	6,405	2,269	1,775	2,248	12,854	2,370
F2023	6,550	2,294	1,782	2,249	13,039	2,396
F2024	6,693	2,316	1,798	2,257	13,236	2,419
F2025	6,838	2,339	1,815	2,263	13,433	2,443
F2026	6,989	2,353	1,778	2,245	13,548	2,458
F2027	7,140	2,376	1,779	2,195	13,678	2,481
F2028	7,296	2,399	1,799	2,200	13,889	2,505
F2029	7,455	2,423	1,836	2,178	14,094	2,530
F2030	7,618	2,447	1,856	2,198	14,331	2,555
F2031	7,785	2,471	1,877	2,249	14,602	2,580
F2032	7,956	2,495	1,898	2,254	14,831	2,605
Growth Rates:						
5 years: F2011 to F2016	2.2%	1.8%	4.6%	7.9%	3.3%	1.8%
11 years: F2011 to F2022	2.0%	1.0%	2.5%	4.7%	2.3%	0.9%
21 years: F2011 to F2032	2.1%	1.0%	1.6%	2.4%	1.9%	0.9%

Notes:

1. Regional peaks include distribution losses only, unless otherwise stated in the table. Regional peaks are not system coincident, as such they do not sum to the Domestic System Peak.
2. Lower Mainland includes peak supply requirement to City of New Westminster and Seattle City Light.
3. South Interior peak includes supply requirement to Fortis BC.
4. Northern Peak includes supply requirement to Hyder, Alaska but does not include Fort Nelson or other Non-Integrated Areas.
5. The Domestic System peak recorded for the winter F2011 was 9,790 MW, excluding curtailment.
6. Actual, weather normalized and forecast values for all Vancouver Island peaks values include Gulf Island peak demand.

LOAD FORECAST TABLES
Table A6.4-A6.5

Table A6.4 2011 Reference Load Forecast before DSM with Rate Impacts (Excluding Initial LNG load)

Total Hydro	2011 REFERENCE FORECAST - PROBABLE - BEFORE DSM WITH RATE IMPACTS (EXCLUDING INITIAL LNG LOAD)											
	BC Hydro Service Area Sales										Integrated System	
	Residential	Commercial	Industrial	Total BCH	Nwest Fortis BC	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Requirement	Total Gross Requirement	Peak
	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(MW)
Actual												
F2007	16,853	15,105	19,469	51,427	1,400	52,828	311	53,139	5,138	58,277	57,982	10,371
F2008	17,462	15,439	18,737	51,639	1,363	53,002	311	53,313	5,722	59,036	58,735	9,861
F2009	17,813	15,577	17,382	50,771	1,291	52,062	308	52,370	5,355	57,725	57,381	10,297
F2010	17,650	15,631	15,608	48,889	1,198	50,087	306	50,393	5,141	55,534	55,220	10,112
F2011	17,898	15,896	15,785	49,579	972	50,552	317	50,869	4,502	55,370	55,047	10,203
Forecast												
F2012	18,199	15,964	16,433	50,597	981	51,578	313	51,891	5,220	57,111	56,803	10,651
F2013	18,652	16,460	17,645	52,756	1,109	53,866	311	54,177	5,426	59,603	59,260	11,026
F2014	19,035	16,957	18,975	54,967	1,250	56,218	311	56,529	5,626	62,154	61,743	11,505
F2015	19,352	17,390	20,082	56,825	1,390	58,215	311	58,527	5,797	64,323	63,895	11,832
F2016	19,711	17,811	20,917	58,438	1,530	59,967	313	60,280	5,956	66,237	65,796	12,140
F2017	20,089	18,196	21,686	59,970	1,536	61,506	311	61,817	6,095	67,912	67,457	12,389
F2018	20,495	18,620	22,317	61,432	1,541	62,973	311	63,284	6,231	69,516	69,055	12,558
F2019	20,923	19,087	22,675	62,686	1,547	64,233	311	64,544	6,354	70,898	70,432	12,737
F2020	21,371	19,433	22,987	63,791	1,553	65,344	313	65,657	6,467	72,124	71,659	12,923
F2021	21,766	19,714	23,037	64,517	1,559	66,076	311	66,387	6,550	72,937	72,476	13,053
F2022	22,218	20,034	23,103	65,355	1,567	66,922	311	67,233	6,643	73,876	73,419	13,197
F2023	22,690	20,353	22,973	66,016	1,575	67,591	311	67,903	6,723	74,626	74,171	13,382
F2024	23,179	20,672	23,049	66,901	1,583	68,483	313	68,796	6,821	75,617	75,164	13,579
F2025	23,615	20,944	22,956	67,515	1,590	69,105	311	69,416	6,896	76,312	75,860	13,775
F2026	24,080	21,267	21,832	67,179	1,598	68,777	311	69,088	6,908	75,996	75,544	13,891
F2027	24,565	21,635	21,899	68,098	1,606	69,704	311	70,015	7,010	77,025	76,573	14,021
F2028	25,105	22,084	21,974	69,163	1,613	70,777	313	71,090	7,128	78,218	77,766	14,232
F2029	25,596	22,535	22,058	70,189	1,621	71,810	311	72,121	7,242	79,363	78,911	14,436
F2030	26,103	23,036	22,312	71,451	1,629	73,080	311	73,391	7,375	80,766	80,315	14,673
F2031	26,613	23,544	22,891	73,047	1,636	74,683	311	74,995	7,532	82,527	82,075	14,945
F2032	27,150	24,069	22,931	74,149	1,644	75,793	313	76,106	7,655	83,761	83,309	15,174
Growth Rates:												
5 yrs F2011-F2016	1.9%	2.3%	5.8%	3.3%	9.5%	3.5%	-0.3%	3.5%	5.8%	3.6%	3.6%	3.5%
11 yrs F2011-F2022	2.0%	2.1%	3.5%	2.5%	4.4%	2.6%	-0.2%	2.6%	3.6%	2.7%	2.7%	2.4%
21 yrs F2011-F2032	2.0%	2.0%	1.8%	1.9%	2.5%	1.9%	-0.1%	1.9%	2.6%	2.0%	2.0%	1.9%

Table A6.5 2011 Reference Load Forecast before DSM with Rate Impacts (Including Initial LNG load)

Total Hydro	**2011 REFERENCE FORECAST - PROBABLE - BEFORE DSM WITH RATE IMPACTS (INCLUDING INITIAL LNG LOAD)**											
	BC Hydro Service Area Sales										Integrated System	
	Residential	Commercial	Industrial	Total BCH	Nwest Fortis BC	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Requirement	Total Gross Requirement	Peak
	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(GW.h)	(MW)
Actual												
F2007	16,853	15,105	19,469	51,427	1,400	52,828	311	53,139	5,138	58,277	57,982	10,371
F2008	17,462	15,439	18,737	51,639	1,363	53,002	311	53,313	5,722	59,036	58,735	9,861
F2009	17,813	15,577	17,382	50,771	1,291	52,062	308	52,370	5,355	57,725	57,381	10,297
F2010	17,650	15,631	15,608	48,889	1,198	50,087	306	50,393	5,141	55,534	55,220	10,112
F2011	17,898	15,896	15,785	49,579	972	50,552	317	50,869	4,502	55,370	55,047	10,203
Forecast												
F2012	18,199	15,964	16,465	50,629	981	51,610	313	51,923	5,224	57,147	56,838	10,656
F2013	18,652	16,460	17,667	52,779	1,109	53,888	311	54,200	5,429	59,628	59,285	11,030
F2014	19,035	16,957	18,998	54,990	1,250	56,240	311	56,551	5,628	62,180	61,768	11,509
F2015	19,352	17,390	20,161	56,904	1,390	58,294	311	58,606	5,805	64,411	63,983	11,845
F2016	19,711	17,811	22,001	59,522	1,530	61,051	313	61,364	6,032	67,396	66,956	12,439
F2017	20,089	18,196	25,238	63,522	1,536	65,058	311	65,369	6,343	71,713	71,258	13,070
F2018	20,495	18,620	27,252	66,368	1,541	67,909	311	68,220	6,577	74,797	74,336	13,238
F2019	20,923	19,087	27,611	67,621	1,547	69,168	311	69,480	6,699	76,179	75,713	13,418
F2020	21,371	19,433	27,922	68,726	1,553	70,279	313	70,592	6,813	77,405	76,940	13,604
F2021	21,766	19,714	27,972	69,452	1,559	71,011	311	71,323	6,895	78,218	77,757	13,733
F2022	22,218	20,034	28,039	70,291	1,567	71,858	311	72,169	6,988	79,157	78,700	13,878
F2023	22,690	20,353	27,909	70,952	1,575	72,527	311	72,838	7,069	79,907	79,452	14,062
F2024	23,179	20,672	27,985	71,836	1,583	73,419	313	73,732	7,167	80,898	80,445	14,259
F2025	23,615	20,944	27,892	72,450	1,590	74,041	311	74,352	7,241	81,593	81,141	14,456
F2026	24,080	21,267	26,767	72,114	1,598	73,712	311	74,024	7,253	81,277	80,825	14,571
F2027	24,565	21,635	26,834	73,034	1,606	74,640	311	74,951	7,355	82,306	81,854	14,701
F2028	25,105	22,084	26,910	74,099	1,613	75,712	313	76,025	7,474	83,499	83,047	14,913
F2029	25,596	22,535	26,993	75,124	1,621	76,745	311	77,057	7,587	84,644	84,192	15,117
F2030	26,103	23,036	27,247	76,386	1,629	78,015	311	78,326	7,721	86,047	85,595	15,354
F2031	26,613	23,544	27,826	77,982	1,636	79,619	311	79,930	7,877	87,807	87,356	15,625
F2032	27,150	24,069	27,866	79,085	1,644	80,729	313	81,042	8,000	89,042	88,590	15,855
Growth Rates:												
5 yrs F2011-F2016	1.9%	2.3%	6.9%	3.7%	9.5%	3.8%	-0.3%	3.8%	6.0%	4.0%	4.0%	4.0%
11 yrs F2011-F2022	2.0%	2.1%	5.4%	3.2%	4.4%	3.2%	-0.2%	3.2%	4.1%	3.3%	3.3%	2.8%
21 yrs F2011-F2032	2.0%	2.0%	2.7%	2.2%	2.5%	2.3%	-0.1%	2.2%	2.8%	2.3%	2.3%	2.1%