Appendix F

Load Forecast Report



2006 Load Forecast

Prepared

September 2006

Table of Contents

Executive Summary 1
Introduction 4
Forecast Models 4
Discussion of Major Inputs 5
Sector Model Inputs 7
Losses 8
Energy Forecast Details 8
Residential Sector Sales 8
Commercial Sector Sales 13
Industrial Sector Sales 15
Total Sales 17
System Losses and Unbilled Sales 17
Net System Requirement 18
Rate Class Sales 19

Residential *19*
Small General *19*
General *20*
Large General *20*
Small Industrial *20*
Medium Industrial *20*
Large Industrial *21*
Municipal *21*
Unmetered Services *22*
Generation Replacement and Load Following *22*
Mersey System *22*
Extra Large Industrial Interruptible Rate (ELIIR) *22*
One-Part Real Time Price (1P-RTP) *23*
Two-Part Real Time Price (2P-RTP) *23*
Extra Large Industrial Interruptible Rate – 2 (ELIIR-2) *23*

System Losses and Unbilled Sales 23
Peak Demand 24
Non Firm Coincident Peak *25*
Total Coincident Firm Peak *25*

Appendix A: 2006 NSPI Forecast 28
Appendix B: Figures 41
Appendix C: High and Low Forecast Scenarios 48
Appendix D: Forecast Sensitivity by Major Variable 51

List of Figures

Figure 1 Annual Net System Requirement 2
Figure 2 Annual Net System Peak (Winter-ending) 2
Figure 3 2007 NSPI Sector Sales 8
Figure 4 Persons per Residential Account 10
Figure 5 Annual NS Heating Degree-Days 11
Figure 6 Annual Energy – Residential Sector 12
Figure 7 Annual Energy – Commercial Sector 14
Figure 8 Annual Energy – Industrial Sector 15

List of Tables

Table 1 Forecast Variables 6
Table 2 Residential Sector Energy 12
Table 3 Commercial Sector Energy 14
Table 4 Industrial Sector Energy 16
Table 5 Total Energy Requirement 18

Executive Summary

The Nova Scotia Power Inc. (NSPI) 2006 Load Forecast provides an outlook on the energy and peak demand requirements of in-province customers for 2006 to 2015. As well, it describes the considerations, assumptions and methodology used in the preparation of the forecast. The NSPI Forecast provides the basis for the financial planning and overall operating activities of the Company.

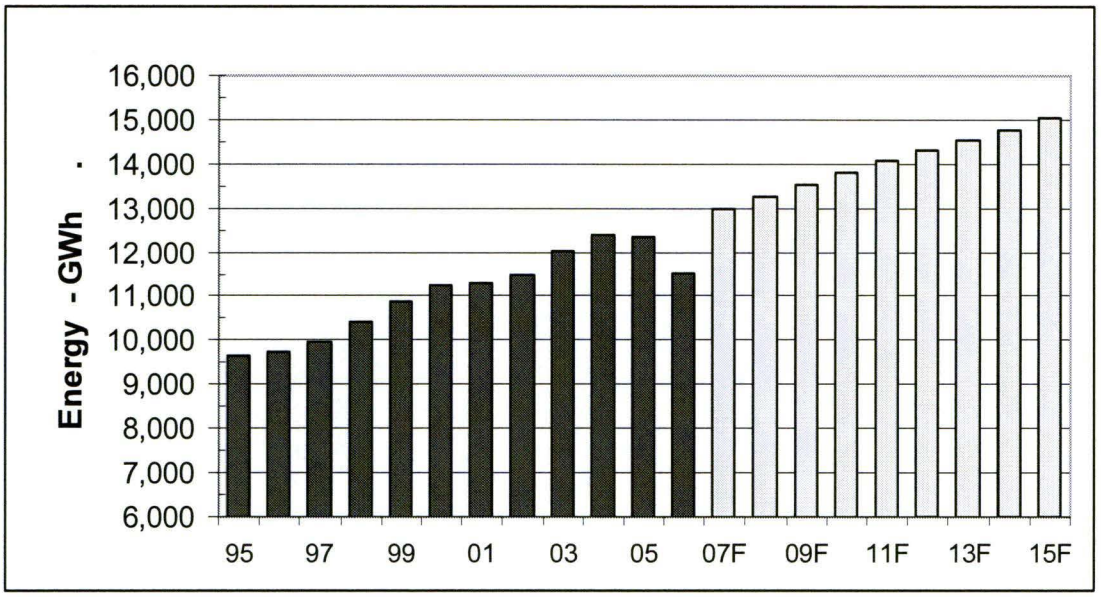
The forecast is based on analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market and the price and availability of other energy sources. Weather conditions, in particular temperature, affect electrical energy and peak demand. The forecast is based on the 30-year average temperatures measured in the Halifax area of the province.

As with any forecast, there is a degree of uncertainty around actual future outcomes. In electricity forecasting, much of this uncertainty is due to the impact of variations in weather, the health of the economy, changes in large customer loads, the number of electric appliances and end-use equipment installed, as well as the manner and degree to which they are used. This forecast presents NSPI's "expected" or "most likely" case for rate-making purposes and also provides less probable, but possible high and low scenarios for longer term planning purposes.

NSPI billed energy sales are initially modeled and forecast as three provincial customer sectors: residential, commercial and industrial. Input variables for each sector are updated and forecast sales calculated using the sector models. The sum of these in-province billed sales plus associated system losses and changes to unbilled sales is then determined. This is referred to as the Net System Requirement (NSR).

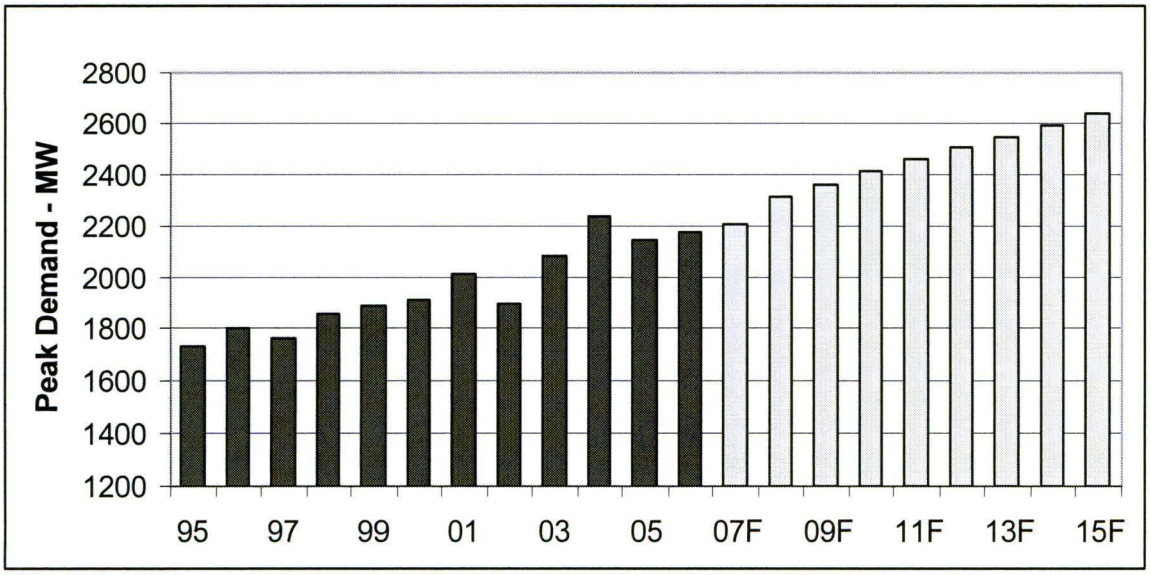
The NSR is forecast to increase from 12,338 GWh in 2005 to 12,981 in 2007, an average increase of 2.6 percent per year. In 2015, NSR is forecast to increase to 15,028, representing an average increase of 2.0 percent per year over the ten year forecast period. Growth in annual net system requirement is shown in Figure 1.

Figure 1 **Annual Net System Requirement**



In addition to annual energy requirements, NSPI also forecasts the peak hourly demand for future years. The process uses forecast energy requirements and expected load shapes (hourly consumption profiles) for the various customer classes. Load shapes are derived from historical analysis, adjusted for any expected changes (e.g. customer plans to add major equipment). Growth in annual net system peak is shown in Figure 2.

Figure 2 **Annual Net System Peak (Winter-ending)**



Over the longer term, Net System Peak is forecast to increase from 2143 MW in 2005, to 2639 MW in 2015, which represents an annual growth rate of 2.1 percent.

The actual hourly peak demand to date in 2006 occurred in February and was 1854 MW, 384 MW lower than the record experienced in 2004 (2238 MW). This lower peak was caused by two factors: first, a large industrial customer shutdown, reducing demand by approximately 215 MW; second, the province experienced a mild winter where temperatures did not go below -10°C around the time of the peak demand (winter peaks are typically set when cold temperatures drive residential and commercial electric space heating load, on weekdays with temperatures in the range of -15°C or colder).

The forecast peak for 2007 is 2256 MW, assuming a return to normal (30 year average) temperatures. No load reductions or changes in demand profiles due to Demand Side Management (DSM) or conservation programs are assumed in this forecast.

Introduction

NSPI annually develops a forecast of energy sales and peak demand requirements to assess the impact of customer, demographic and economic factors on the future provincial system load. It is a fundamental input to the overall planning, budgeting and operating activities of the Company. Produced in the spring of 2006 and using information available at the time, this forecast covers the 10-year period of 2006 - 2015. Unless otherwise noted, average growth rates stated report the average annual rate calculated between 2005 (the last year of actual data) and 2015.

Forecast Models

Nova Scotia electric energy sales are modeled and forecast as three provincial customer sectors: residential, commercial and industrial. Energy forecasts for sector electricity sales are calculated using econometric models in conjunction with forecasts for the independent variables used in those models. Individual customer load forecast survey information is also used for large customers in the Commercial and Industrial sectors.

The sector econometric models are multiple linear regression equations that are designed to capture the relationships between electricity consumption and several independent variables. The models then use these relationships to predict future energy loads. An examination of these variables provides a meaningful explanation of the load growth in each sector. The individual econometric model details are shown in the Appendices.

The variables used in the preparation of the forecast include population, residential customer growth, inflation, GDP, retail sales, oil and electricity prices, appliance saturation levels and average energy use, water and space heat saturation levels and heating degree-days. The primary source of economic and other provincial statistics used in the load forecast is the Conference Board of Canada's *Economic Outlook*, which is released quarterly. This forecast provides a provincial perspective and considers specific Nova Scotia projects and demographics.

While there may be some reduction in energy consumption as a result of increasing electricity prices, the elasticity has generally been quite small. This forecast is required in advance of, and

used as part of the input to determining what, if any increase might be required and therefore this potential but small impact has not been explicitly modeled in this forecast.

Discussion of Major Inputs

The Gross Domestic Product (GDP) for Nova Scotia was $23,528 million (in constant 1997 dollars) in 2005, and is forecast to increase by 2.2 percent in 2006 and 2.5 percent in 2007. This growth continues to be fuelled by a broad base of economic gains. The last federal budget contained increased expenditures for the military, a major contributor to the Halifax area economy. Other budget items such as the reduction in the GST should offer some gains in disposable income and provide for further growth in the retail sector. Housing starts and sales have remained strong, but are expected to soften slightly with possibility of increased mortgage rates. Major commercial investments include the $270 million development at Dartmouth Crossing, the new development centre for Research In Motion and the start-up of the $400 million Sydney Tar Ponds clean-up project. Container traffic through the Port of Halifax is expected to continue to grow as more ships get routed to North America through the Suez Canal. While the elevated Canadian dollar will squeeze the margins of many provincial manufacturers, it could also provide these same manufacturers with opportunities to invest in foreign-sourced equipment (now relatively cost-effective), thereby boosting future productivity. Tourism will continue to be challenged in the face of high gasoline prices and the high dollar.

In 2004, the provincial Consumer Price index (CPI) slowed to 1.8 percent growth from 3.4 percent in 2003. In 2005, CPI growth rose to 2.8 percent and it is forecast to grow at 2.2 percent for 2006, 1.7 percent in 2007, and remain at 1.9 percent or less for the next several years as the Bank of Canada maintains inflation below its 2 percent target.

Single housing starts were approximately 3180 in 2005, and are forecast by the Conference Board of Canada (CBoC) to be 3223 for 2006. For 2007, single starts are forecast at 2460. The housing market is expected to weaken with the satisfaction of pent-up demand. Meanwhile, future demand is expected to become more aligned to the underlying demographics. Additionally, there has been some deterioration in affordability in urban areas. Multi-unit starts were approximately 1590 in 2005 and are forecast to decrease to approximately 720 in 2006 and 540 in 2007.

Retail sales, with 2.8 percent growth in 2004, grew by 3.5 percent in 2005. Strong growth is forecast to be maintained at a rate of 3.8 percent in 2006 and 3.7 percent in 2006 and 2007, as consumer confidence remains positive.

Nova Scotia population in 2005 was estimated to be 937,818 with an average annual growth rate of just 0.07 percent in the past 5 years. Despite the continuing focus on immigration, there is little indication that the prevailing trends will be altered soon, particularly as migration to the bustling economies of the western provinces seems to be picking up. Further population growth is not anticipated in the forecast with the estimate for 2010 at 935,215 for an annual growth rate of -0.06 percent.

Table 1 lists the annual growth rates of some of the major independent variables that affect the forecast.

Table 1 **Forecast Variables**

Forecast Variables	2005 Actual Growth Rate	2006 Forecast Growth Rate	2007 Forecast Growth Rate
N.S. Population	0.02%	-0.11%	-0.04%
N.S. Consumer Price Index	2.8%	2.2%	1.7%
N.S. Real Personal Disposable Income	1.7%	2.2%	2.0%
N.S. Real GDP at basic prices	2.4%	2.2%	2.5%
N.S. Retail Sales	3.5%	3.8%	3.7%
Real residential heating oil price change	19.5%	6.3%	4.3%

Sector Model Inputs

A factor influencing the residential forecast involves market effects including the price of electricity versus other alternatives (e.g. fuel oil) and the effects of natural gas distribution. The stock of electric appliances is estimated through maturities and conversion rates to and from electric units as well as the electric heat penetration for new construction. Technology factors are considered through increases in efficiency and the introduction of new equipment such as Electric Thermal Storage (ETS) units

The outlook for the retail price of furnace oil (#2 light) is consistent with other fuel prices used by NSPI. The ratio of oil prices to electricity prices is used in calculating the saturation of residential water and space heating equipment. Furnace oil prices are estimated to average 91¢ per litre in 2006 and 97¢ in 2007.

Assumptions regarding the effects of natural gas distribution in the province are based on the potential loss of electric space heating and water heating load. The gas impact on this forecast is small however, due to a limited rollout plan. Continued high prices for natural gas are also expected be a deterrent to switching to gas from electric where gas is available.

Electricity sales in the commercial sector are influenced by the level of business activity and as a result, are closely related to the provincial GDP and consumer confidence.

Electricity sales to small and medium industrial customers are correlated to general economic growth in the province. However, energy use in the industrial sector is also highly influenced by large industries such as forestry and pulp & paper. Since changing economic conditions, exchange rates and trade policies can create large fluctuations in sales as companies expand, contract or endure inventory shutdowns; the large industrial forecast relies heavily on input from customer surveys.

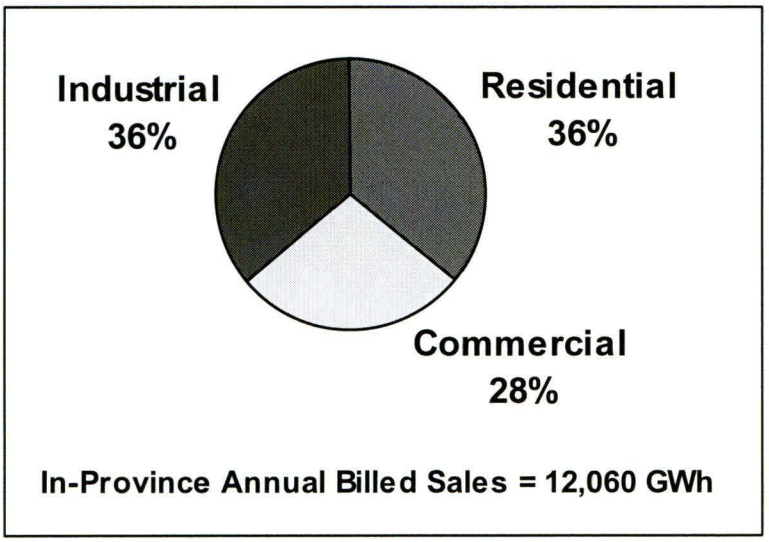
Losses

System losses have averaged 7.0 percent of NSR over the past five years and are expected to remain in the 7 percent range over the 10 year forecast period.

Energy Forecast Details

For forecasting, modeling and sales reporting, Nova Scotia electric load is divided into three sector requirements: residential, commercial and industrial. The relative sizes of sector sales are shown in Figure 3.

Figure 3 **2007 NSPI Sector Sales**



Residential Sector Sales

In 2005, residential customers represented approximately 36 percent of total Nova Scotia energy sales. In addition to direct domestic customers of the Company, the sector also includes residential customers served by six municipal utilities. Seasonal residences comprised 6.5 percent of the residential base.

The residential sector offers an opportunity for more detailed modeling due to the relative similarity of customer end-uses, compared to the wide variations in end-use by commercial and industrial customers.

The residential sector forecast is prepared using an econometric model that uses forecast retail sales, an overall end-use appliance index, a variable representing electric heating load, residential electricity cost per kWh and residential electric load from the previous year. A series of end-use models are used to calculate the appliance index and space heating variable forecasts.

A population forecast is used in conjunction with customer formation trends to produce a residential customer count forecast. Sector average electricity costs per kWh and forecast furnace oil prices are used in a market share model to estimate the annual electric space and water heat penetration rates. A composite variable (CHDD) is calculated for use in the residential model that takes into account the annual number of all-electric customers and the forecast heating degree-days.

Household appliance load is modeled using non-linear regression methods that forecast the annual saturation rates of major appliances. Efficiency improvements for new units are accounted for in the stock vintage models that calculate the overall system average use for each appliance type given the age and efficiency mix of the total stock. This appliance saturation and average use information is used to create a composite variable (AIDX), which is used in the residential sector econometric model.

The real cost of electricity is another factor that may affect residential electricity consumption. Consumers may respond to increases in energy prices by reducing consumption or delaying the acquisition of a major appliance, however the price elasticity of this sector appears to be quite small in the near-term. The econometric model uses the average sector customer price per kWh after tax measured in constant dollars (RREP).

Provincial economic trends are represented in the residential sector model through the forecast of Retail Sales, as measured in current dollars.

To capture the overall sector growth trends, the residential electric load of the previous year is included in the model as a lagged dependent variable. It should be noted however, that the coefficients applied to this and the other variables are the result of estimates using data compiled

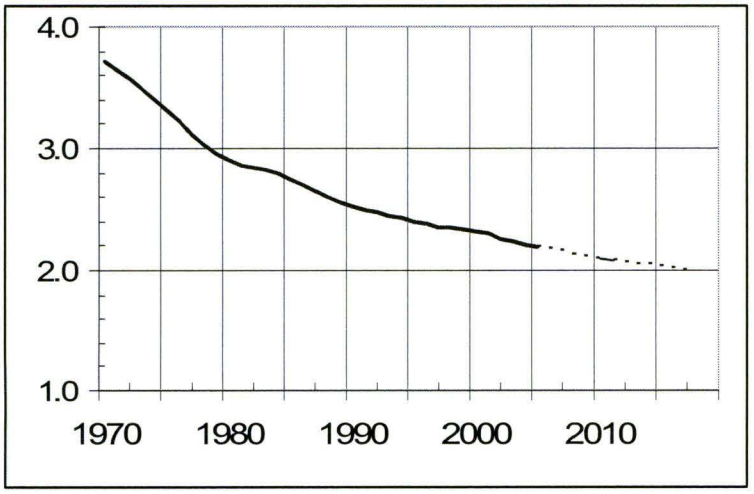
over a 30-year period, and are therefore reflective of longer term relationships and not just the prior year's results.

The residential econometric model is shown below. Complete residential sector model fit statistics and model specifications are provided in the Appendix of this report.

$$Residential\ Load = 683.4\ AIDX + 0.1257\ CHDD - 31.79\ RREP + 0.07878\ RRTS + 0.4599\ Residential\ load_{-1}$$

The forecast for new customers for 2006 is 3921 including seasonal, diminishing to 2405 by 2015. The number of additions has been decreasing steadily from more than 4500 in 1997. Although the Nova Scotia population is expected to grow at a very low rate or even decrease, Nova Scotians are increasingly choosing to live in smaller households. This trend is indicated in Figure 4. The result is an increase in the overall number of households, which in turn boosts total electric customers for a given population.

Figure 4 **Persons per Residential Account**



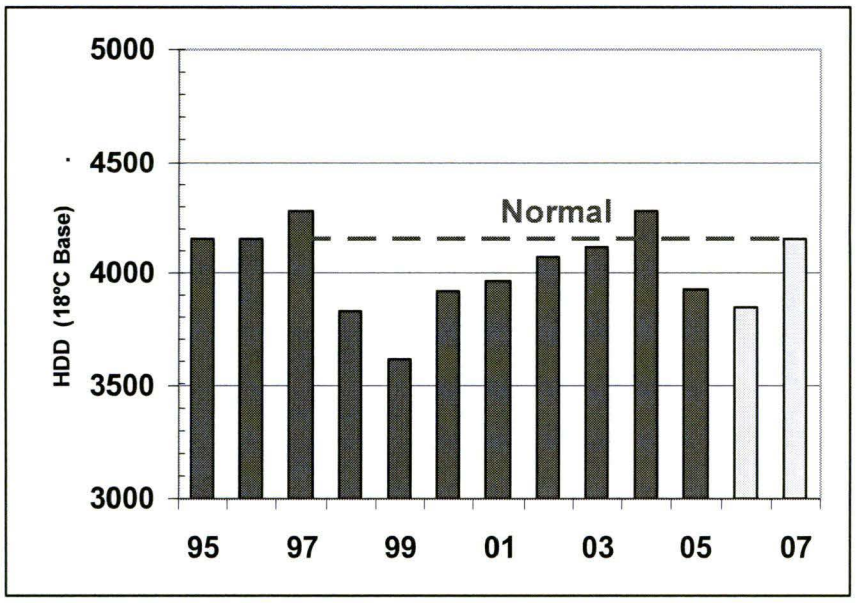
With an ever-increasing array of new technology available, usage per customer continues to grow, despite efficiency improvements for many household appliances. Larger appliances are modeled individually considering the age, efficiency trends and acquisition rates. Efficiency improvements for televisions, dishwashers, clothes washers, and water heaters are forecast at 0.5 percent per year over the forecast period. Efficiency improvements in electric ranges are forecast at 1 percent per year. These improvements apply only to new appliances, and as a

result, the effect on the overall system load is very gradual as older appliances are retired and replaced with more efficient models.

With the rapidly rising oil prices and increasing concerns over hazardous oil spills, the market share of electric space heat has crept up slightly. The saturation of electric space heat has been in the mid to high 20 percent range in recent years and was estimated to be 30 percent in 2005 with continuing customer additions. The saturation of electric water heating hovers around 55 percent and is forecast to grow slowly over the forecast period.

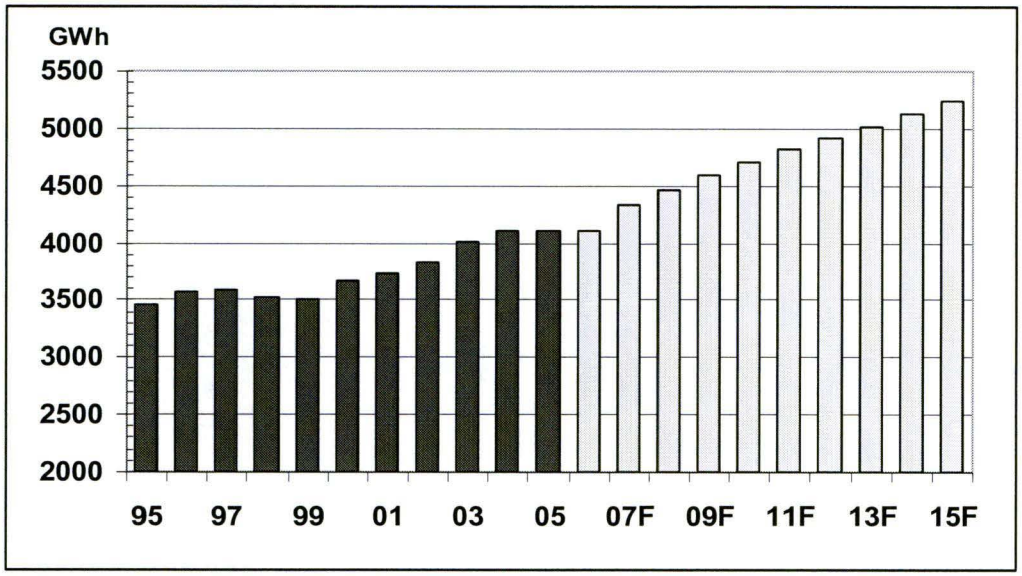
The forecast for weather effects uses 30-year average temperatures, measured in heating degree-days (HDD). Heating degree-days are a common measure of heating requirement, based on the degree departure between the daily mean temperature and a given standard temperature. The standard temperature of 18°C is used for these calculations and is assumed to be a comfortable room temperature below which space heating is generally required. The 30-year average is commonly used as the standard benchmark. The forecast uses the Environment Canada HDD data for Shearwater Airport for the years 1976-2005 and is 4150.1. Figure 5 shows the variation in annual HDDs over the past ten years as well as the forecast for 2006 and 2007.

Figure 5 **Annual NS Heating Degree-Days**



The residential sector load has grown at an average annual rate of 2.3 percent over the past five years or 1.8 percent when adjusted for the effects of weather. Annual residential loads are shown in Figure 6.

Figure 6 **Annual Energy – Residential Sector**



The 2007 load forecast for this sector is 4,327 GWh, or 2.9 percent over the forecast 2006 level.

Table 2 **Residential Sector Energy**

Year	Residential Sector GWh	Growth Rate %
2000	3,672.1	4.6
2001	3,741.2	1.9
2002	3,828.9	2.3
2003	4,010.5	4.7
2004	4,113.5	2.4
2005	4,114.3	0.0
2006F	4,203.6	2.2
2007F	4,326.9	2.9
2008F	4,466.2	3.2
2009F	4,588.4	2.7
2010F	4,706.4	2.6
2011F	4,813.9	2.3
2012F	4,917.5	2.2
2013F	5,018.0	2.0
2014F	5,122.7	2.1
2015F	5,240.2	2.3

Over the 10 year forecast period the residential load is expected to average 2.4 percent per year, reflecting the trend toward more electric heating customers as furnace oil prices are assumed to remain relatively high. Natural gas distribution is not expected to significantly impact the residential sector load in the near term due to limited distribution and expected high gas prices.

Commercial Sector Sales

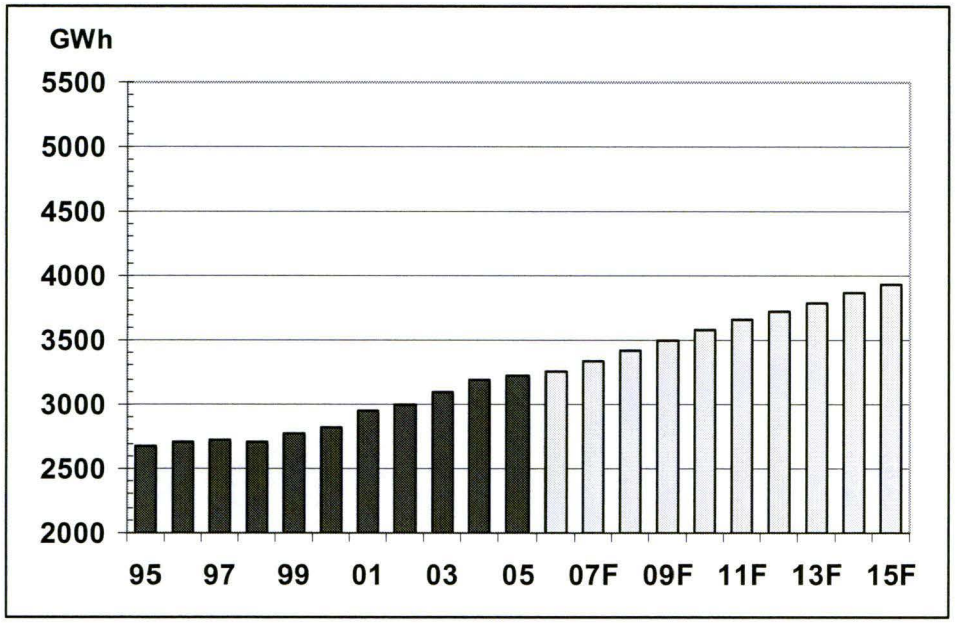
Energy sales to the commercial sector in 2005 represented 28 percent of Nova Scotia sales. This customer group includes restaurants, hotels, offices, recreational facilities, stores warehouses hospitals, schools and universities and street and traffic lights, as well as commercial customers served by municipal utilities. The level of business activity in the province is a major factor in determining the energy sales to this sector. The level of business activity is captured in GDP and as a result, a strong correlation exists between commercial energy requirements and real GDP. Real personal disposable income (RPDI) is also correlated to activity in the commercial sector and is included in the model.

The commercial sector forecast is produced using an econometric model using real GDP, RPDI, residential electricity sales and the commercial electricity sales from the previous year. The equation is shown below. Complete details of the commercial sector model are presented in the Appendix of this report.

$$Commercial = 0.01838\ RQTOS + 0.01969\ RPDI + 0.2015\ Residential + 0.5146\ Commercial\ load_{-1}$$

Additionally, the largest commercial customers are surveyed to obtain their forecasts of any foreseen load changes. This information is used in a reconciliation of the sector load by rate class. Annual commercial sector loads are indicated in Figure 7.

Figure 7 **Annual Energy – Commercial Sector**



Growth in this sector has averaged 2.6 percent over the past 5 years (2.4 percent when adjusted for weather). Driven by strong wholesale trade, consumer confidence and growth in personal disposable income boosting retail trade activity, this sector is forecast to grow by 1.6 percent and 2.1 percent in 2006 and 2007, respectively. The annual growth rate is expected to average 2.0 percent over the next 10 year period. The annual commercial sector loads are shown in Table 3.

Table 3 **Commercial Sector Energy**

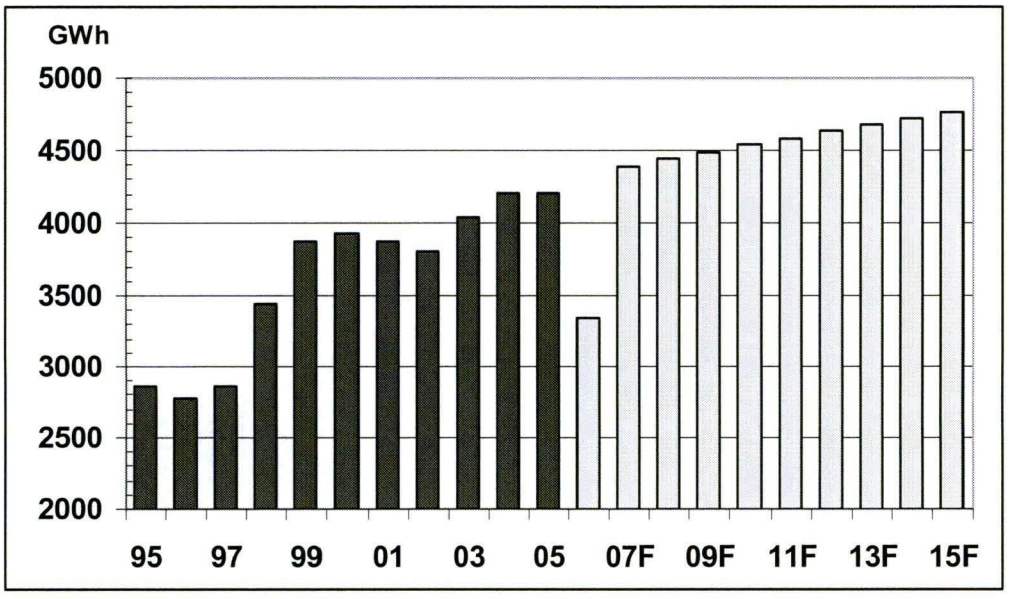
Year	Commercial Sector GWh	Growth Rate %
2000	2,829.4	2.3
2001	2,959.3	4.6
2002	2,996.5	1.3
2003	3,090.6	3.1
2004	3,187.8	3.1
2005	3,223.2	1.1
2006F	3,275.4	1.6
2007F	3,344.6	2.1
2008F	3,423.2	2.3
2009F	3,502.8	2.3
2010F	3,581.4	2.2
2011F	3,656.7	2.1
2012F	3,728.2	2.0
2013F	3,797.7	1.9
2014F	3,864.5	1.8
2015F	3,932.7	1.8

Industrial Sector Sales

In 2005, the industrial sector represented 36 percent of Nova Scotia total electricity sales. This group comprises customers who process raw materials or manufacture finished goods. It includes both primary resource industries such as mining and forestry as well as secondary industries such as manufacturing and food processing. While this sector is made up of over 2,000 customers, a few large customers represent most of the energy. For instance, the five largest customers use two-thirds of the energy in this sector and one-quarter of in-province energy sales. With relatively few customers representing a large proportion of the load in this sector, changes in production levels, equipment and technology changes, expansion or downsizing can have a significant impact on the load.

The demand for manufactured and processed goods is driven by exports as well as the health of the provincial economy. Annual industrial sector loads are shown in Figure 8.

Figure 8 **Annual Energy – Industrial Sector**



The load for this sector is forecast using a combination of econometric modeling and large customer surveys. To avoid the effects of customers migrating between the classes, the Small and Medium Industrial customer loads are combined and forecast together using an econometric model. The economic factors that influence these customers are assumed to be the same regardless of the demand criterion that determines the customer's particular rate class. The

growth rates calculated from the model are then used to forecast each class. This model relates industrial electricity consumption to GDP and load in the preceding year. In the early 1990s, significant load migrated from the Medium Industrial class to the new Interruptible Industrial Rate. A dummy variable, MIGRATE, is used in the model to capture that effect.

The Small and Medium Industrial econometric model equation is shown below. Complete fit statistics and model specifications are shown in the Appendix to this report.

$$SM_IND = 0.009305\ RQTOS + 0.7441\ SM_IND._1 - 28.70\ MIGRATE$$

Large customers are surveyed each year in order to gather their forecast monthly electricity requirements over the next three year period, given planned production levels and equipment changes. The information is used as input to prepare the large industrial load forecast by rate class. The annual industrial sector loads are shown in Table 4.

Table 4 **Industrial Sector Energy**

Year	Industrial Sector GWh	Growth Rate %
2000	3,930.0	1.5
2001	3,872.5	-1.5
2002	3,798.6	-1.9
2003	4,045.9	6.5
2004	4,212.1	4.1
2005	4,215.1	0.1
2006F	3,362.4	-20.2
2007F	4,388.4	30.5
2008F	4,438.0	1.1
2009F	4,487.2	1.1
2010F	4,536.4	1.1
2011F	4,585.0	1.1
2012F	4,632.8	1.0
2013F	4,680.0	1.0
2014F	4,725.8	1.0
2015F	4,770.7	1.0

In the fall of 2004 one of NSPI's largest customers completed a sizeable process expansion, which substantially increased their load over 2003. At the end of 2005, that customer had a temporary shutdown and is expected to remain closed for much of 2006. The forecast for 2007 assumes the plant will be at normal full load. With no new expansions or customer additions of

large magnitude anticipated for 2006 or 2007, growth in the industrial sector will level off in the near-term.

Industrial sector load growth averaged 1.4 percent per year from 2000-2005, but dips by 20 percent in 2006 due to the major customer shutdown. The forecast load for 2007 is 4,388 GWh with major customers assumed at normal full load. Between 2005-2015, growth is expected to average 1.2 percent in this sector.

Total Sales

Given the combined activities of each sector, including large industrial shutdowns, expansions, etc., total sales grew at an average annual rate of 2.5 percent over the last 10 years. As a result of each of the sector sales forecasts, total Nova Scotia sales are expected to grow at an average annual rate 1.9 percent over the next 10 years. The billed sales are therefore expected to grow from 11,553 GWh in 2005 to 13,944 GWh by the year 2015.

System Losses and Unbilled Sales

The load forecast is developed using NSPI "billed" sales rather than "accrued" sales to provide a longer historical time series upon which to base the models. Billed sales refers to the amount of energy billed to customers in a given time period such as a calendar month or a year, whereas accrued sales recognizes the amount of energy actually generated and consumed during that specific time period. Due to the periodic nature and delays inherent in any meter reading and billing process, billed sales will vary somewhat from accrued sales. The difference in the energy generated and sold but not yet billed, is referred to as "Unbilled" sales.

The difference between energy generated for use within provincial borders and the total NSPI billed sales comprises system losses as well as changes to the level of unbilled sales. Losses of approximately 6 percent of sales to municipal utility service areas are also included in this total Nova Scotia losses estimate.

Losses are estimated at both the transmission and distribution levels. Historical estimates for transmission losses are obtained from NSPI's Supervisory Control and Data Acquisition (SCADA) system and are based upon an expected generation and transmission configuration. As a result, transmission losses are forecast at 3.0 percent of the transmission energy requirement. Based on historical estimates, distribution losses are forecast at approximately 6.2 percent of distribution sales. As a result of forecast distribution and transmission losses, total system losses average 6.9 percent of NSR over the forecast period.

Net System Requirement

The Net System Requirement (NSR) is the energy required to supply the sum of residential, commercial, and industrial electricity sales, plus the associated system losses within the province of Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses associated with energy exports are not included. Annual NSR is shown in Table 5.

Table 5 **Total Energy Requirement**

Year	Net System Requirement GWh	Growth Rate %
2000	11,240.1	3.4
2001	11,303.2	0.6
2002	11,501.0	1.8
2003	12,009.1	4.4
2004	12,387.6	3.2
2005	12,338.1	-0.4
2006F	11,784.1	-4.8
2007F	12,980.6	10.5
2008F	13,272.1	2.2
2009F	13,544.7	2.1
2010F	13,812.0	2.0
2011F	14,063.6	1.8
2012F	14,305.8	1.7
2013F	14,541.6	1.6
2014F	14,777.7	1.6
2015F	15,028.4	1.7

The Net System Requirement for the province has grown at an average of 1.9 percent per year from 2000-2005 and is forecast to average 2.0 percent over the next 10 years.

Rate Class Sales

Forecast sales by sector are allocated into 14 rate classes for revenue forecasting purposes. The following section describes these rate classes and their expected energy requirements for the forecast period. In most cases, load growth trends by rate class are due to the same factors that affect the sector to which they belong, however, migration of customers between rate classes in the same sector can affect both historical and forecast energy requirements by class. Sales requirements by class are computed using historical and forecast trends and customer migration between classes.

Residential

This class includes residential sector customers served directly by NSPI and represented 35 percent of total NSPI sales in 2005. All-electric, non-all-electric and residential Time-of-Day (TOD) rate customers are included in this class. As of December 2005, there were approximately 423,500 domestic customers responsible for annual billed sales of 4,039 GWh, an average of 9,537 kWh/customer. Residential class sales grow for the reasons stated in the residential sector description, and are forecast to grow at an average of 2.4 percent per year over the forecast period.

Small General

In the past, this class has comprised commercial sector customers whose annual energy consumption was less than 12,000 kWh. In January 2004, by UARB Order in the fall of 2002, this availability threshold increased to 22,000 kWh/yr, and was increased again to 32,000 kWh/yr in January 2005. This moved some customers previously billed under the General (medium commercial) rate to Small General, thereby decreasing the load in the General class and increasing the Small General load. At the end of 2005, this class was comprised of approximately 22,000 customers. It represented 109 GWh in sales in 2003, 165 GWh in 2004 and 232 GWh in 2005. With the rate migration completed, it is forecast at 242 GWh in 2007 and a return to approximately 2 percent per year growth.

General

In the past, this class comprised commercial sector customers whose annual energy consumption was greater than 12,000 KWh and for whom no other class was applicable. As discussed in the Small General class section, this threshold was changed in 2004 and 2005 causing a migration of customers from General to Small General. As of 2005, this class had approximately 11,200 customers accounting for the major portion of commercial sector energy and 21 percent of total NSPI sales for 2005. By 2007, energy sales for this class are anticipated to be 2,476 GWh and grow annually at an average of 2.1 percent over the forecast period.

Large General

This class comprises large commercial sector customers (malls, universities, hospitals, etc) whose regular maximum demand is 2,000 kVA or more. As of December 2005, there were 18 customers in this class representing 3.6 percent of NSPI sales. Annual load growth over the entire forecast period is expected to average 1.6 percent.

Small Industrial

This class comprises small industrial, farming and processing customers whose regular demand is less than 250 kVA. This class was made up of 2,212 customers as of December 2005, and had energy sales representing 2.1 percent of NSPI total sales. Energy requirements in this class are forecast to grow at an average rate of 2.0 percent per year over the forecast period.

Medium Industrial

This class is applicable to any industrial customer having a regular demand of at least 250 kVA, but less than 2,000 kVA. As of December 2005, there were 225 customers in this class, representing about 4.8 percent of total NSPI sales. Class sales are forecast to grow at an average of 2.0 percent over the next 10 years.

Large Industrial

This class is available to larger industrial customers having a regular demand of 2,000 KVA or more. As of December 2005, there were six customers in the "firm load" category. Customers in this class may choose to have all or a portion of their load served as interruptible in nature with the remaining load considered firm, In 1996, the Interruptible rate class was eliminated and the rate was attached to the Large Industrial class as a rider, available to those customers who have contracted to reduce their system load by a specified demand within 10 minutes of a request by NSPI. Customers on the rider receive a reduction in demand charge for billed interruptible kVA. As of December 2005, there were 25 customers on the Large Industrial Interruptible Rider. The combined energy for the firm and interruptible customers represented 997 GWh, or 8.6 percent of total 2005 NSPI energy sales. The anticipated combined energy for firm and interruptible customers in 2007 is 1,079 GWh, or 8.9 percent of total sales.

Municipal

This class comprises municipal utilities that purchase wholesale electricity from NSPI and distribute it within their own service territories. The six municipalities are: Antigonish, Berwick, Canso, Lunenburg, Mahone Bay and Riverport. Loads within these municipalities include customers in residential, commercial and industrial sectors, and have been included in NSPI's total Nova Scotia sector sales estimates. Energy in this class also includes the losses incurred by the municipal utility in delivering the electricity requirements. These losses are estimated to average approximately 6 percent of sales.

The UARB recently approved the Open Access Transmission Tariff (OATT), which supports the opening of the electricity market in Nova Scotia to power producers and the six municipal utilities. Beginning in 2006, it will be possible for these municipalities to source their electricity from providers other than NSPI. In 2005, this class represented 1.7 percent of total NSPI sales. Municipal sales are forecast to grow at an average annual rate of 2.1 percent over the next 10 years.

Unmetered Services

This class comprises street and area lighting, as well as miscellaneous lighting and small loads. In 2005, unmetered sales represented approximately 0.9 percent of total NSPI sales. Energy sales in this class are forecast to grow at an average of 2.0 percent over the forecast period.

Generation Replacement and Load Following

This class is available to customers who have their own generation capacity of no less than 2,000 kW. As of December 2005, this class comprised three customers and represented about 0.1 percent of total NSPI sales. This class is also interruptible load and is currently forecast to remain near its 2005 level of approximately 12 GWh annually.

Mersey System

This class involves specific contract energy to one customer, Bowater Mersey Paper Company, in accordance with the Mersey System Agreement.

Extra Large Industrial Interruptible Rate (ELIIR)

This rate is calculated annually in advance and based on NSPI's budgeted base load costs. It is optionally available to, and currently in use by, two large industrial customers who commit blocks of more than 20 MW of load and are served at 138KV or more. This rate was designed to reward high monthly load factors and contains an economic interruptibilty provision. In addition, it is priority interruptible in nature from a supply perspective. Sales under this rate in 2005 were 1791 GWh or approximately 16 percent of NSPI sales. The ELIIR rate remains in place for 2006, but will be replaced in 2007 with a newly developed rate.

One-Part Real Time Price (1P-RTP)

This is an energy-only rate based on NSPI's 20 minute-ahead forecast hourly marginal energy costs plus differing fixed cost adders for on-peak and off-peak usage. It is available to customers served at transmission or distribution voltages with loads of 2,000 kVA or more. The fixed cost adders are calculated annually in advance and are based on NSPI's budgeted costs. Potentially lower prices in off-peak periods can provide an incentive to customers to shift energy consumption from weekdays to nights and weekends, off the NSPI system peak. This rate was used significantly in 2001 and 2002, but became unattractive to customers in 2003 as off-peak marginal costs rose.

Two-Part Real Time Price (2P-RTP)

By its September 28, 2006 Decision in the matter of replacing the ELIIR rate, the UARB directed NSPI to modify the formerly approved 2P-RTP to incorporate aspects contained in that Decision. NSPI, as directed, will file the revised rate on October 16, 2006. Until that time, specific details of the rate and associated load remain uncertain.

Extra Large Industrial Interruptible Rate – 2 (ELIIR-2)

By its September 28, 2006 Decision in the matter of replacing the ELIIR rate, the UARB directed NSPI to modify the existing ELIIR rate to incorporate aspects contained in that Decision. NSPI, as directed, will file the revised rate on October 16, 2006. Until that time, specific details of the rate and associated load remain uncertain.

System Losses and Unbilled Sales

This category includes NSPI transmission losses, distribution losses and the year-over-year change in unbilled sales. The annual change in unbilled sales is currently in the order of 14 GWh, based on forecast growth in the accrued sales classes. Losses on sales within the service area of municipal utilities are not included in this class, but are included in the municipal rate class to which they belong. Transmission losses are forecast at approximately 3.0 percent of the transmission system energy requirement. NSPI distribution losses are forecast at 6.2 percent of

distribution level sales. Residential and commercial classes tend to have higher losses due to the lower voltages at which they are served. The overall mix of sales to each sector results in total NSPI losses which are forecast to average 6.9 percent of NSR over the forecast period.

Peak Demand

The Total System Peak is defined as the highest single hourly average demand experienced in a year. It includes both firm and interruptible loads and due to the weather-sensitive load component in Nova Scotia, the Total System peak occurs in the period from December through February.

Although peak demands are measured on an individual hour-by hour-basis and are not directly related to monthly heating degree days, January 2006 did not have particularly cold weather. The monthly peak of 1798 MW occurred at a temperature of just -6°C and a largest industrial customers were operating approximately 225 MW below typical load.

The February 2006 peak was only slightly higher at 1854 MW, with termperature of -10°C and the largest industrial customers were again approximately 225 MW below typical loads.

With the exception of large customer classes, monthly and annual Net System Peaks are computed using forecast monthly energies and average historical coincident load factors for each of the rate classes. For large customers, individual demand contributions to system peak are assessed based on recent history or new customer information. Monthly peak loss percentages are applied to each monthly sales peak to produce losses by class and are then summed to produce the total peak demand forecast. This method produces forecast peaks that while not explicitly tied to a particular hourly temperature, recognize and average the actual peak and energy relationships from recent years.

The system peak for 2007 is forecast at 2256 MW. Over the longer term, Net System Peak is forecast to increase from 2143 MW in 2005 to 2639 MW in 2015, which represents an average annual growth rate of 2.1 percent.

Non Firm Coincident Peak

NSPI offers interruptible, or "non-firm" service to industrial customers who meet certain criteria and contract to have their electricity supply interrupted on short notice in order to meet any necessary emergency peak reductions. These rate classes are the "Generation Replacement and Load Following" rate, the "Extra Large Industrial Interruptible" rate and the "Interruptible" rider of the Large Industrial rate. As of the January 2005 peak, there were 30 customers on these rates, representing a combined coincident non-firm peak of 392 MW.

Non-firm coincident peak demand is forecast explicitly by customer for the near-term and an allowance is made for unallocated or new customer growth in the longer term. The customers who currently take non-firm service are expected to continue on the rate and therefore non-firm coincident peak is forecast to grow only moderately from its current level assuming there are no major changes made to the rate's availability or requirements over the forecast period.

Total Coincident Firm Peak

Total Coincident Firm Peak is the demand at the time of NSPI's system peak that is attributable to all firm classes (e.g.: residential, small general, etc), but excluding the non-firm customer classes mentioned above.

Total Non-coincident Firm Peak is defined as the highest peak demand for the combined firm classes, which may or may not be coincident with the time of NSPI's total system peak, depending upon non-firm customer demand fluctuations.

While strictly speaking, the Firm Non-coincident Peak is generally referred to with respect to planning, NSPI typically uses Total Coincident Firm Peak as being representative of Total Non-Coincident Firm Peak, given that it is much more readily available each month (estimating non-coincident peak requires a full hourly load shape analysis, whereas coincident peak focuses on the peak hour only).

Load shape statistics indicate that especially during winter months, the non-coincident firm peak and the coincident firm peak are usually close, due to the peak often being driven by cold temperatures.

Load Forecast

Appendices

Appendix A

2006 NSPI Forecast

Residential Sector Econometric Model Detail

$$DOMENG = 683.4\ AIDX + 0.1257\ CHDD - 31.79\ RREP + 0.07877\ RRTS + 0.4599\ DOMENG_{-1}$$

```
Forecast Model for DOMENG
Regression(5 regressors, 0 lagged errors)

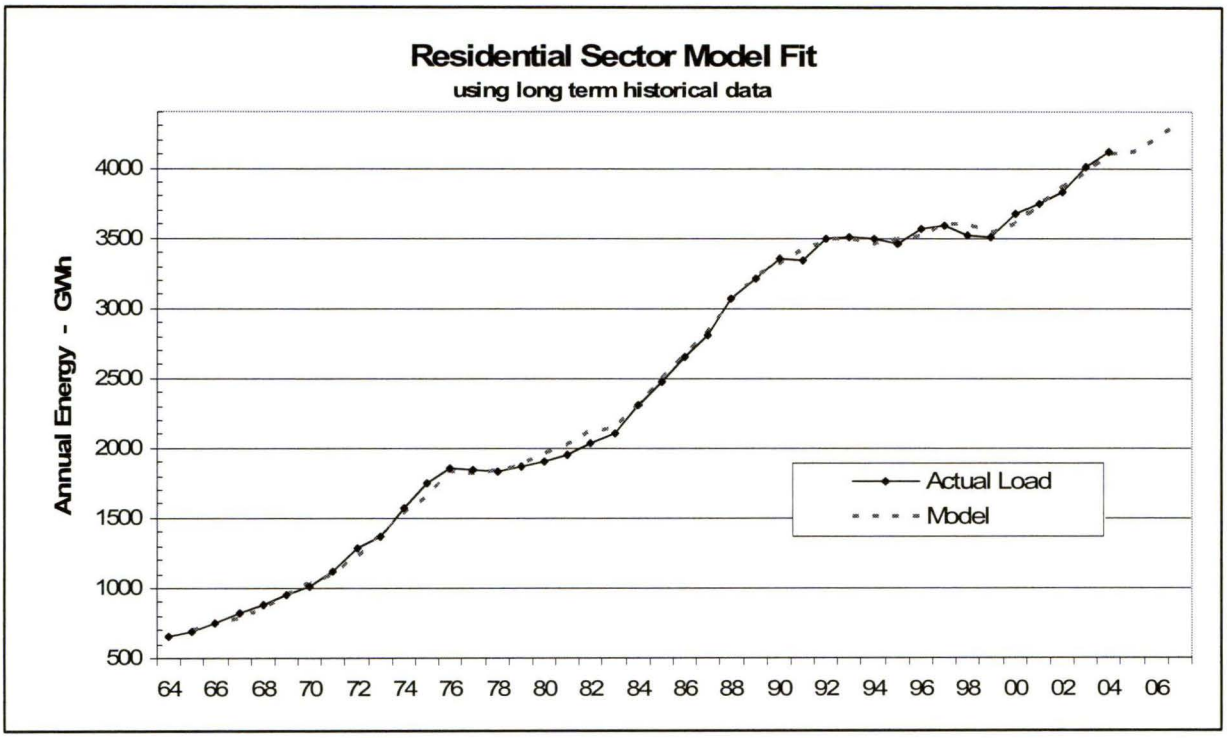
Term                 Coefficient  Std. Error  t-Statistic  Significance
------------------------------------------------------------------------
EFFIDX             683.420493    74.620566     9.158608     1.000000
CUSTHDD              0.125711     0.035709     3.520432     0.998811
RREP               -31.791492     5.282988    -6.017710     0.999999
RRTS                 0.078778     0.012295     6.407588     1.000000
DOMENG[-1]           0.459957     0.075438     6.097196     0.999999

Within-Sample Statistics
------------------------------------------------------------
Sample size 41                   Number of parameters 5
Mean 2499                        Standard deviation 1096
R-square 0.9984                  Adjusted R-square 0.9982
Durbin-Watson 1.523              Ljung-Box(18)=18.36 P=0.5681
Forecast error 46.15             BIC 54.23
MAPE 0.01681                     RMSE 43.24
MAD 34.81
```

Residential Model Input Variables and Contributions

Year	AIDX	AIDX Contrib.	CHDD	CHDD Contrib.	Electric Price	Electric Price Contrib.	Retail Sales	Retail Sales Contrib.	DomEng[-1]	DomEng[-1] Contrib.	Nat. Gas Effect	DomEng*	Actual	Growth
		GWh		GWh		GWh		GWh		GWh	GWh	GWh	GWh	%
1994	1.79	1221.2	3,192	401.2	9.94	-316.0	6,859	540.3	3,506.9	1,613.0	0	**3459.8**	**3498.3**	-0.2%
1995	1.77	1209.8	3,574	449.2	9.80	-311.7	6,795	535.3	3,498.3	1,609.1	0	**3491.8**	**3462.9**	-1.0%
1996	1.75	1193.3	3,714	466.9	10.03	-319.0	7,455	587.3	3,462.9	1,592.8	0	**3521.3**	**3564.6**	2.9%
1997	1.74	1189.6	3,798	477.5	9.79	-311.3	7,762	611.5	3,564.6	1,639.6	0	**3606.9**	**3594.8**	0.8%
1998	1.73	1182.2	3,460	435.0	9.79	-311.1	8,103	638.4	3,594.8	1,653.5	0	**3597.9**	**3524.4**	-2.0%
1999	1.71	1165.8	3,223	405.1	10.16	-323.0	8,615	678.7	3,524.4	1,621.1	0	**3547.6**	**3512**	-0.4%
2000	1.67	1144.7	3,529	443.7	9.75	-310.0	8,956	705.5	3,512.0	1,615.4	0	**3599.2**	**3672.1**	4.6%
2001	1.68	1144.9	3,727	468.5	9.53	-303.0	9,278	730.9	3,672.1	1,689.0	0	**3730.3**	**3741.2**	1.9%
2002	1.66	1132.2	4,213	529.6	9.28	-294.9	9,840	775.1	3,741.2	1,720.8	0	**3862.9**	**3828.9**	2.3%
2003	1.67	1137.9	4,463	561.0	9.19	-292.1	10,015	789.0	3,828.9	1,761.1	0	**3956.9**	**4010.5**	4.7%
2004	1.64	1118.7	4,871	612.3	9.00	-286.2	10,297	811.1	4,010.5	1,844.7	0	**4100.7**	**4113.5**	2.6%
2005	1.63	1115.2	4,634	582.6	9.36	-297.6	10,655	839.4	4,113.5	1,892.0	0	**4114.3**	**4114.3**	0.0%
2006	1.63	1112.5	5,282	664.1	9.97	-317.1	11,055	870.9	4,113.2	1,891.9	-0.3	**4203.6**		2.2%
2007	1.63	1110.7	5,653	710.6	9.81	-311.9	11,460	902.8	4,203.6	1,933.5	-0.4	**4326.9**		2.9%
2008	1.62	1108.3	5930	745.4	9.27	-294.7	11,882	936.1	4326.9	1,990.2	-0.7	**4466.2**		3.2%
2009	1.62	1106.2	6101	767.0	9.17	-291.5	12,340	972.1	4466.2	2,054.2	-1.3	**4588.4**		2.7%
2010	1.62	1104.2	6235	783.8	8.79	-279.5	12,792	1007.7	4588.4	2,110.5	-1.7	**4706.4**		2.6%
2011	1.62	1102.4	6367	800.4	8.82	-280.4	13,293	1047.2	4706.4	2,164.8	-2.1	**4813.9**		2.3%
2012	1.61	1101.2	6503	817.5	8.85	-281.3	13,794	1086.7	4813.9	2,214.2	-2.4	**4917.5**		2.2%
2013	1.61	1100.1	6645	835.3	8.96	-285.0	14,302	1126.7	4917.5	2,261.8	-2.6	**5018.0**		2.0%
2014	1.61	1099.2	6785	852.9	8.88	-282.2	14,799	1165.8	5018.0	2,308.1	-2.8	**5122.7**		2.1%
2015	1.61	1098.7	6923	870.3	8.48	-269.6	15,307	1205.9	5122.7	2,356.2	-2.9	**5240.2**		2.3%

* - to align forecast to actuals in 2005, the modeled DomEng contains a launch adjustment of 18.4 GWh for 2005-2015


Residential Sector Model Fit
using long term historical data
Annual Energy - GWh
4000
3500
3000
2500
2000
1500
1000
500
64 66 68 70 72 74 76 78 80 82 84 86 88 90 92 94 96 98 00 02 04 06
Actual Load
Model

Commercial Sector Econometric Model Detail

$$COMENG = 0.01838\ RQTOS + 0.01968\ RPDI + 0.2015\ DOMENG + 0.5145\ COMENG_{-1}$$

Forecast Model for COMENG
Regression(4 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance
RQTOS	0.018387	0.003946	4.660185	0.999960
RPDI	0.019686	0.006249	3.150433	0.996777
DOMENG	0.201502	0.043502	4.631997	0.999956
COMENG[-1]	0.514591	0.075251	6.838373	1.000000

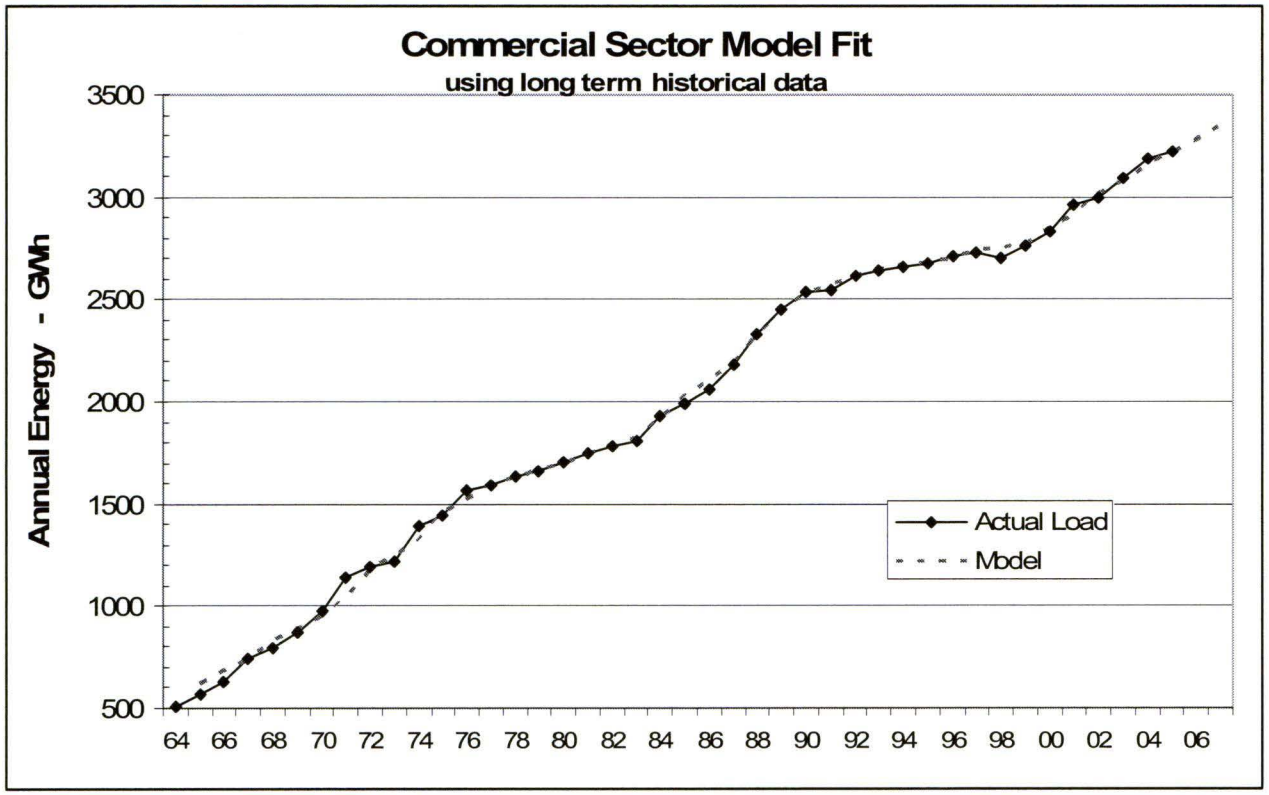
Within-Sample Statistics

Sample size 41	Number of parameters 4
Mean 2008	Standard deviation 778.1
R-square 0.9983	Adjusted R-square 0.9982
Durbin-Watson 1.89	Ljung-Box(18)=8.424 P=0.02837
Forecast error 32.91	BIC 37.47
MAPE 0.01641	RMSE 31.26
MAD 22.82	

Commercial Model Input Variables and Contributions

Year	RQTOS	RQTOS contrib GWh	RPDI	RPDI contrib GWh	DomEng	DomEng contrib GWh	ComEng[-1]	ComEng[-1] contrib GWh	ComEng* GWh	Actual GWh	Growth %
1994	17,535	322.4	14,168	278.9	3,498.3	704.9	2,638.3	1,357.6	**2,663.9**	2,660.2	0.8
1995	17,888	328.9	14,273	281.0	3,462.9	697.8	2,660.2	1,368.9	**2,676.6**	2,676.0	0.6
1996	17,922	329.5	14,027	276.1	3,564.6	718.3	2,676.0	1,377.0	**2,701.0**	2,712.9	1.4
1997	18,379	337.9	14,258	280.7	3,594.8	724.4	2,712.9	1,396.0	**2,739.0**	2,725.3	0.5
1998	19,063	350.5	14,796	291.3	3,524.4	710.2	2,725.3	1,402.4	**2,754.4**	2,702.4	-0.8
1999	20,169	370.8	15,254	300.3	3,512.0	707.7	2,702.4	1,390.6	**2,769.5**	2,766.8	2.4
2000	20,867	383.7	15,354	302.3	3,672.1	739.9	2,766.8	1,423.8	**2,849.7**	2,829.4	2.3
2001	21,607	397.3	15,593	307.0	3,741.2	753.9	2,829.4	1,456.0	**2,914.1**	2,959.3	4.6
2002	22,415	412.1	15,619	307.5	3,828.9	771.5	2,959.3	1,522.8	**3,014.0**	2,996.5	1.3
2003	22,630	416.1	15,540	305.9	4,010.5	808.1	2,996.5	1,542.0	**3,072.1**	3,090.6	3.1
2004	22,981	422.5	15,697	309.0	4,113.5	828.9	3,090.6	1,590.4	**3,150.8**	3,187.8	3.1
2005	23,528	432.6	15,958	314.1	4,113.1	828.8	3,187.8	1,640.4	**3,215.9**	3,223.2	1.1
2006	24,035	441.9	16,304	321.0	4,203.5	847.0	3223.0	1,658.5	**3,275.4**		1.6
2007	24,624	452.8	16,634	327.5	4,326.8	871.9	3275.4	1,685.5	**3,344.6**		2.1
2008	25,097	461.5	16,947	333.6	4,466.2	899.9	3344.6	1,721.1	**3,423.2**		2.3
2009	25,582	470.4	17,238	339.3	4,588.4	924.6	3423.2	1,761.5	**3,502.8**		2.3
2010	26,103	480.0	17,450	343.5	4,706.4	948.4	3502.8	1,802.5	**3,581.4**		2.2
2011	26,554	488.2	17,700	348.4	4,813.9	970.0	3581.4	1,842.9	**3,656.6**		2.1
2012	26,963	495.8	17,926	352.9	4,917.5	990.9	3656.7	1,881.7	**3,728.3**		2.0
2013	27,371	503.3	18,173	357.7	5,018.0	1,011.1	3728.2	1,918.5	**3,797.7**		1.9
2014	27,678	508.9	18,393	362.1	5,122.7	1,032.2	3797.7	1,954.2	**3,864.5**		1.8
2015	27,993	514.7	18,616	366.5	5,240.2	1,055.9	3864.5	1,988.6	**3,932.7**		1.8

* - to align forecast to actuals in 2005, the modeled ComEng contains a launch adjustment of 7.0 GWh for 2005-2015


Commercial Sector Model Fit
using long term historical data
Annual Energy - GWh
3500
3000
2500
2000
1500
1000
500
64 66 68 70 72 74 76 78 80 82 84 86 88 90 92 94 96 98 00 02 04 06
Actual Load
Model

Industrial Econometric Model Details

Small and Medium Industrial Classes are summed and modeled together.

$$SM_IND = 0.009305\ RQTOS + 0.7441\ SM_IND_{-1} - 28.69\ MIGRATE$$

Forecast Model for SM_IND
Regression(3 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance
MIGRATE	-28.699063	6.694597	-4.286899	0.999745
RQTOS	0.009305	0.002628	3.540010	0.998331
SM_IND[-1]	0.744101	0.083565	8.904460	1.000000

Within-Sample Statistics

Sample size 27	Number of parameters 3
Mean 566	Standard deviation 125.4
R-square 0.9866	Adjusted R-square 0.9855
Durbin-Watson 1.022	* Ljung-Box(18)=33.36 P=0.9849
Forecast error 15.11	BIC 17.1
MAPE 0.01931	RMSE 14.24
MAD 10.42	

Industrial Model Input Variables and Contributions

Year	RQTOS	RQTOS contrib GWh	MIGRATE	MIGRATE contrib GWh	$SM_Ind_{[-1]}$	$SM_Ind_{[-1]}$ contrib GWh	SM_Ind* GWh	Actual GWh	Growth %
1994	17,535	163.2	1	-28.7	517.8	385.3	**519.7**	528.3	2.0
1995	17,888	166.4	1	-28.7	528.3	393.1	**530.9**	529.6	0.2
1996	17,922	166.8	1	-28.7	529.6	394.1	**532.1**	530.9	0.3
1997	18,379	171.0	0	0.0	530.9	395.1	**566.1**	569.2	7.2
1998	19,063	177.4	0	0.0	569.2	423.5	**600.9**	606.6	6.6
1999	20,169	187.7	0	0.0	606.6	451.3	**639.0**	670.0	10.5
2000	20,867	194.2	0	0.0	670.0	498.6	**692.7**	703.5	5.0
2001	21,607	201.0	0	0.0	703.5	523.5	**724.5**	740.3	5.2
2002	22,415	208.6	0	0.0	740.3	550.8	**759.4**	766.8	3.6
2003	22,630	210.6	0	0.0	766.8	570.6	**781.1**	795.9	3.8
2004	22,981	213.8	0	0.0	795.9	592.2	**806.1**	806.6	1.3
2005	23,528	218.9	0	0.0	806.6	600.2	**798.2**	798.2	-1.0
2006	24,035	223.6	0	0.0	798.1	593.9	**817.5**		2.4
2007	24,624	229.1	0	0.0	817.5	608.4	**837.4**		2.4
2008	25,097	233.5	0	0.0	837.5	623.2	856.8		2.3
2009	25,582	238.0	0	0.0	856.8	637.5	875.6		2.2
2010	26,103	242.9	0	0.0	875.6	651.6	894.5		2.2
2011	26,554	247.1	0	0.0	894.5	665.6	912.7		2.0
2012	26,963	250.9	0	0.0	912.7	679.2	930.1		1.9
2013	27,371	254.7	0	0.0	930.1	692.1	946.9		1.8
2014	27,678	257.5	0	0.0	946.9	704.6	962.2		1.6
2015	27,993	260.5	0	0.0	962.2	715.9	976.5		1.5

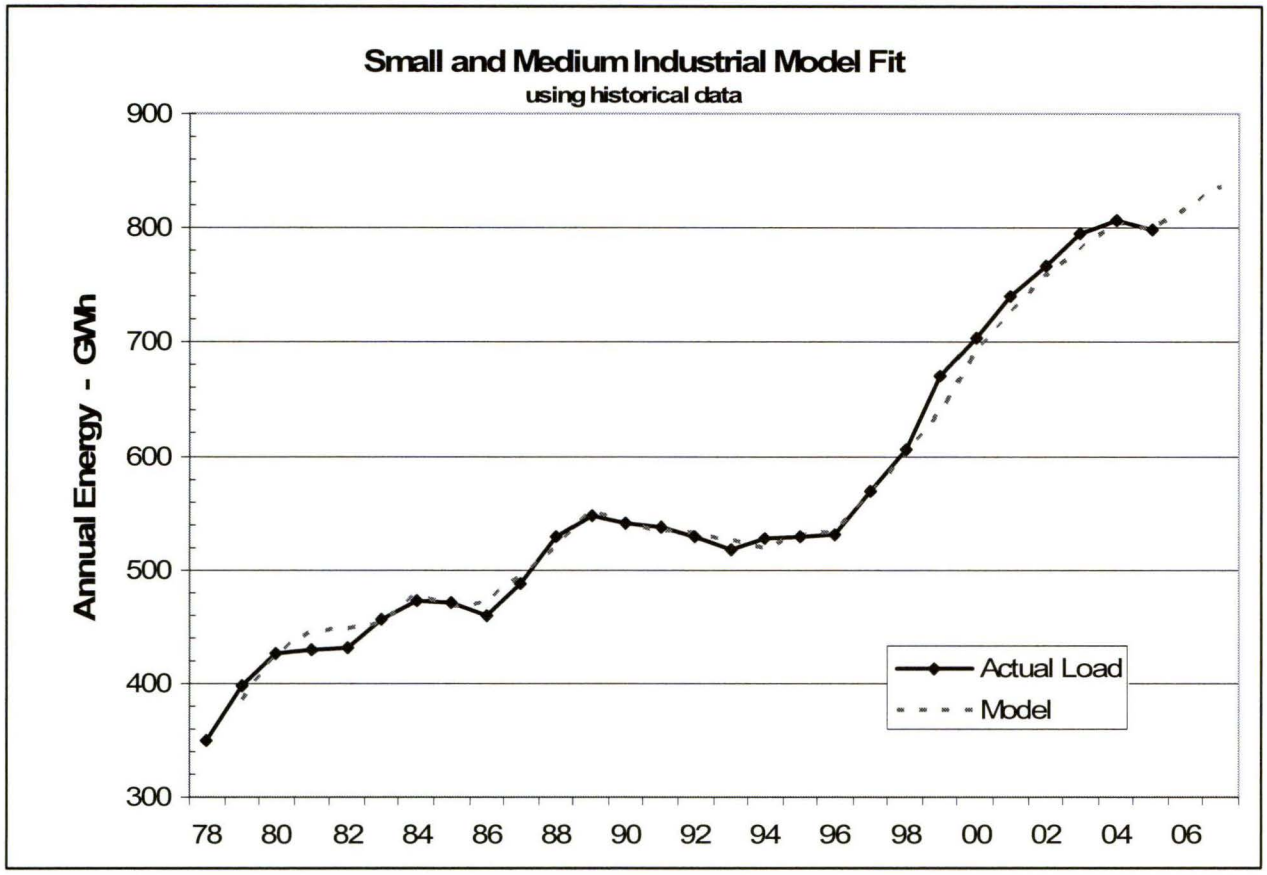

Small and Medium Industrial Model Fit
using historical data
Annual Energy - GWh
900
800
700
600
500
400
300
78
80
82
84
86
88
90
92
94
96
98
00
02
04
06
Actual Load
Model

Table A1: Energy Requirement – 2006 NSPI Forecast

Energy Forecast

Year	Residential Sector GWh	Growth %	Commercial Sector GWh	Growth %	Industrial Sector GWh	Growth %	Total Sales GWh	Growth %	Losses GWh	Total Energy GWh	Growth %
1994	3,498	0.4	2,660	1.0	2,756	0.3	8,914	0.5	679	9,593	0.0
1995	3,463	-1.0	2,676	0.6	2,864	3.9	9,003	1.0	671	9,674	0.8
1996	3,565	2.9	2,713	1.4	2,774	-3.1	9,052	0.5	701	9,753	0.8
1997	3,595	0.8	2,725	0.5	2,867	3.3	9,187	1.5	778	9,965	2.2
1998	3,524	-2.0	2,702	-0.8	3,442	20.1	9,668	5.2	743	10,412	4.5
1999	3,512	-0.4	2,767	2.4	3,872	12.5	10,150	5.0	720	10,870	4.4
2000	3,672	4.6	2,829	2.3	3,930	1.5	10,431	2.8	809	11,240	3.4
2001	3,741	1.9	2,959	4.6	3,873	-1.5	10,573	1.4	730	11,303	0.6
2002	3,829	2.3	2,996	1.3	3,799	-1.9	10,624	0.5	877	11,501	1.8
2003	4,010	4.7	3,091	3.1	4,046	6.5	11,147	4.9	862	12,009	4.4
2004	4,114	2.6	3,188	3.1	4,212	4.1	11,513	3.3	874	12,388	3.2
2005	4,114	0.0	3,223	1.1	4,215	0.1	11,553	0.3	785	12,338	-0.4
2006	4,204	2.2	3,275	1.6	3,362	-20.2	10,841	-6.2	907	11,748	-4.8
2007	4,327	2.9	3,345	2.1	4,388	30.9	12,060	11.2	921	12,981	10.5
2008	4,466	3.2	3,423	2.3	4,438	1.1	12,327	2.2	945	13,272	2.2
2009	4,588	2.7	3,503	2.3	4,487	1.1	12,578	2.0	966	13,545	2.1
2010	4,706	2.6	3,581	2.2	4,536	1.1	12,824	2.0	988	13,812	2.0
2011	4,814	2.3	3,657	2.1	4,585	1.1	13,056	1.8	1008	14,064	1.8
2012	4,918	2.2	3,728	2.0	4,633	1.0	13,279	1.7	1027	14,306	1.7
2013	5,018	2.0	3,798	1.9	4,680	1.0	13,496	1.6	1046	14,542	1.6
2014	5,123	2.1	3,864	1.8	4,726	1.0	13,713	1.6	1065	14,778	1.6
2015	5,240	2.3	3,933	1.8	4,771	1.0	13,944	1.7	1085	15,028	1.7

Table A2: Coincident Peak Demand - 2006 NSPI Forecast

Peak Forecast

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2009	6.6	412	33.3	1597	1.3
2001	1988	-1	369	-10.4	1619	1.4
2002	2078	4.5	348	-5.7	1730	6.9
2003	2074	-0.2	291	-16.4	1783	3.1
2004	2238	7.9	377	29.6	1861	4.4
2005	2143	-4.2	392	4.0	1751	-5.9
2006	2029	-5.3	386	-1.5	1644	-6.1
2007	2256	11.2	381	-1.3	1876	14.1
2008	2312	2.4	385	1.2	1927	2.7
2009	2363	2.2	390	1.1	1973	2.4
2010	2413	2.1	394	1.1	2019	2.3
2011	2460	1.9	399	1.1	2061	2.1
2012	2504	1.8	403	1.1	2102	2.0
2013	2548	1.7	407	1.0	2141	1.9
2014	2592	1.7	411	1.0	2181	1.9
2015	2639	1.8	415	1.0	2224	2.0

Table A3: Energy Sales by Rate Class - 2005 NSPI Forecast

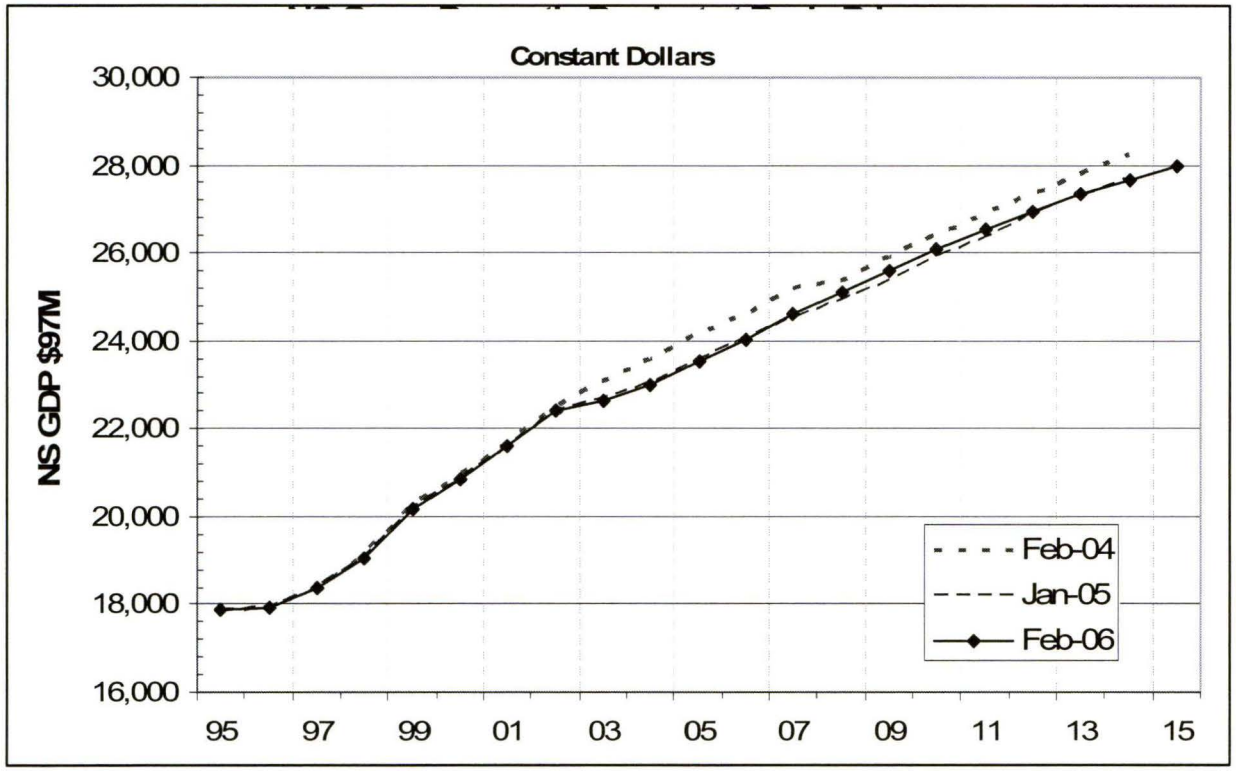
Rate Class Energy Sales

Class Sales (GWh)	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006	2007
Residential	3,760	3,940	4,040	4039	4130	4251
Small General	104	109	165	232	237	242
General Demand	2,350	2,417	2,426	2381	2424	2476
Large General	358	375	401	413	413	421
Unmetered	100	102	105	108	110	112
Small Industrial	235	238	239	241	247	253
Medium Industrial	531	558	567	557	571	585
Large Industrial	292	330	135	143	135	137
RTP	85	26	49	234	161	218
L.I. Interruptible	1,038	1,147	924	853	924	942
Mersey System	190	190	190	190	189	189
Mersey Additional Energy					179	179
GR&LF	444	385	223	190	12	12
Municipal	178	184	190	191	192	196
Ind. Expansion Rate	968	1,158	0	0	0	0
ELII Rate	0	0	1,870	1791	930	1858
Total Billed Sales	10,635	11,158	11,525	11,564	10,853	12,072
Losses & Unbilled	866	851	863	774	895	909
Net System Requirement	11,501	12,009	12,388	12,338	11,748	12,981

Appendix B

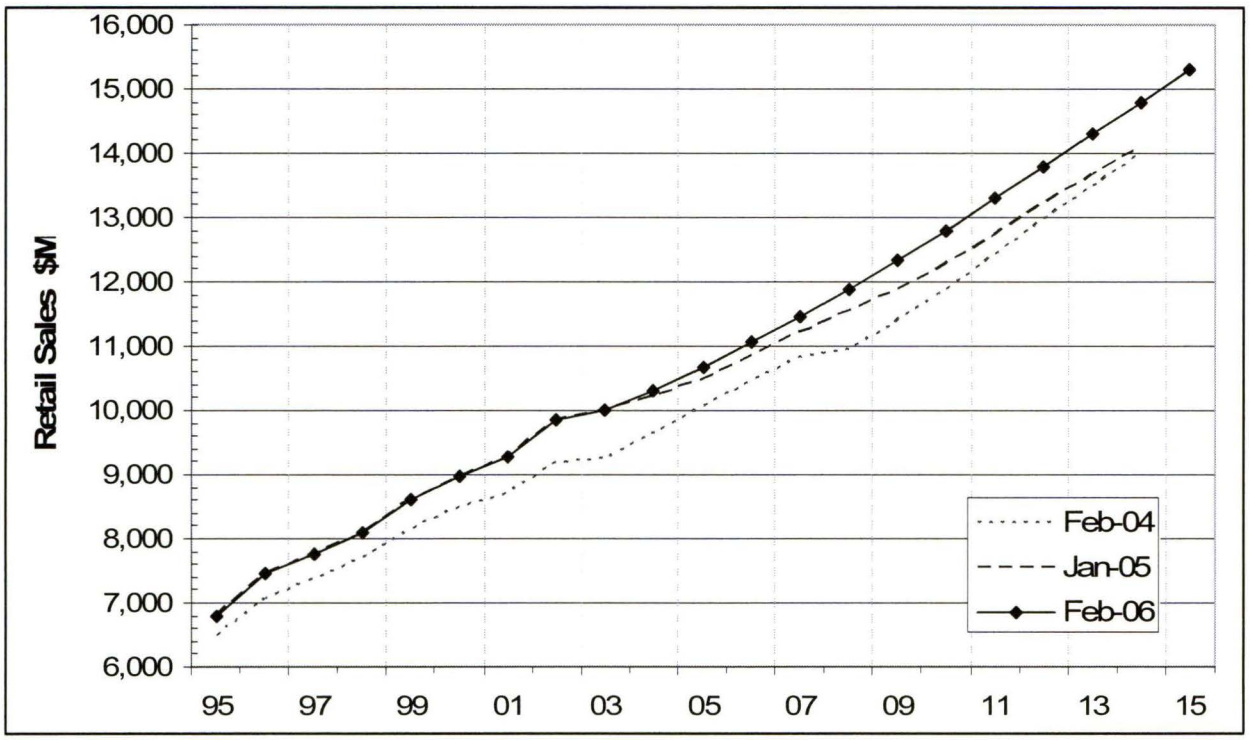
Figures

Figure B1: NS Gross Domestic Product Basic Prices



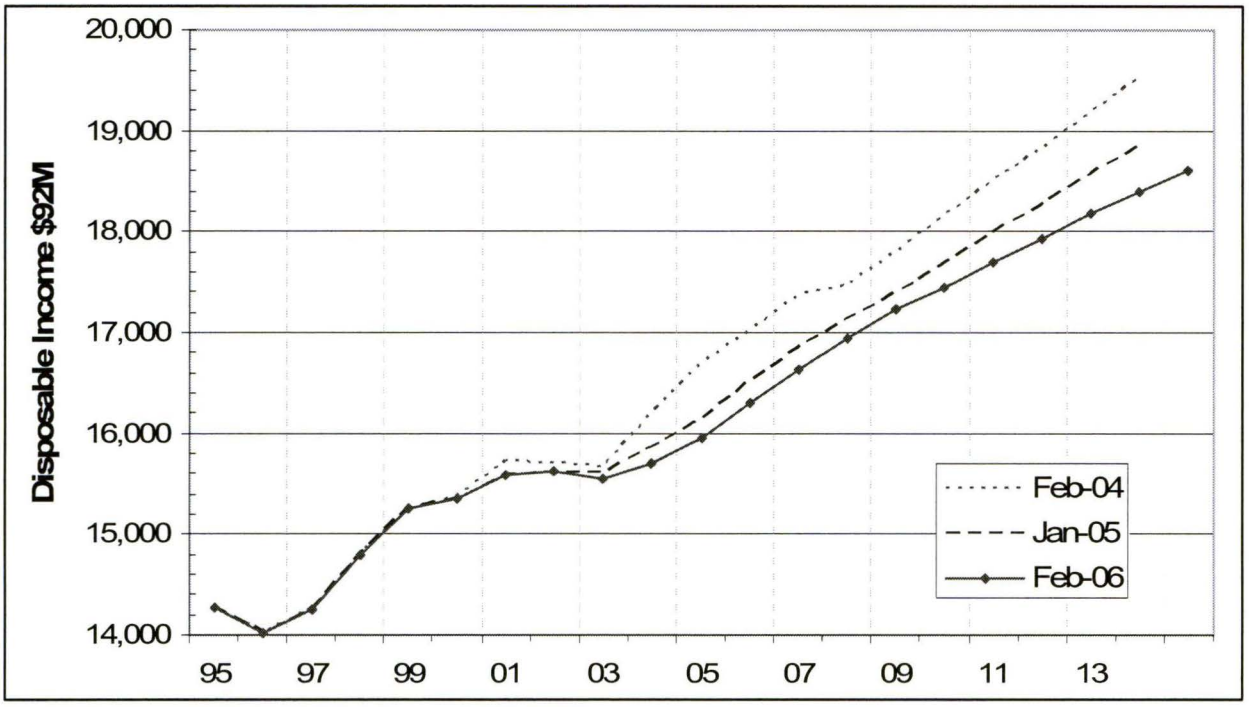
Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B2: NS Retail Sales



Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B3: NS Real Disposable Income



Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B4: NS Energy Sales

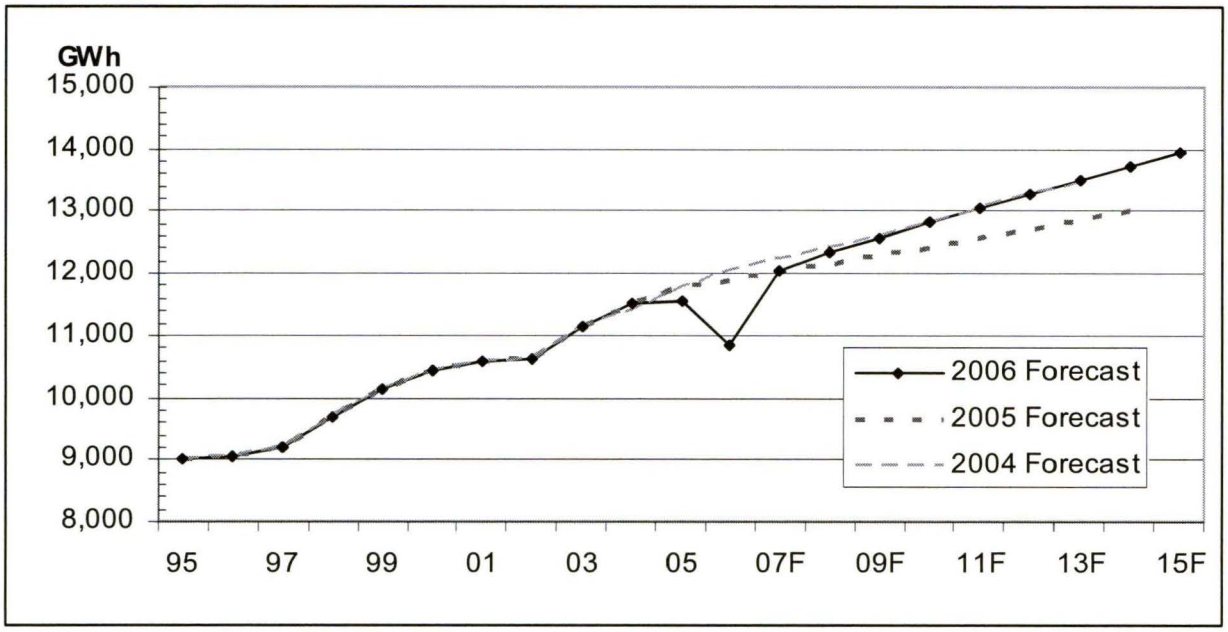


Figure B5: Total NS Energy Losses

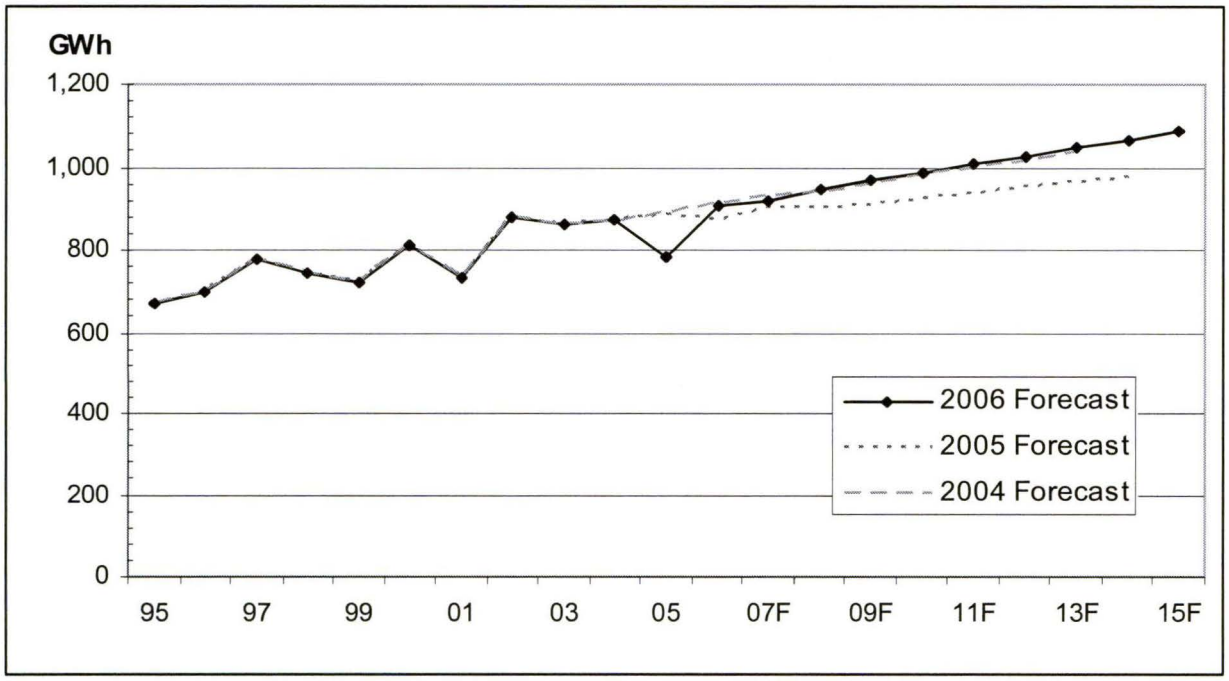


Figure B6: Total NS Energy Requirement

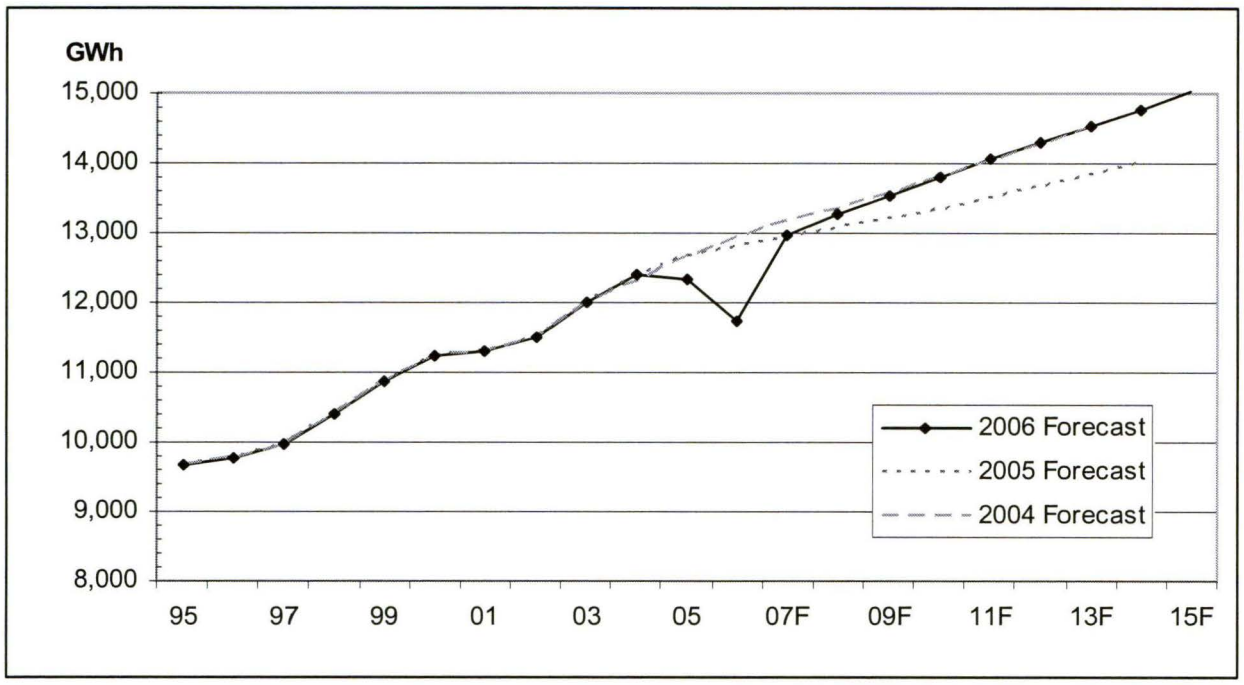
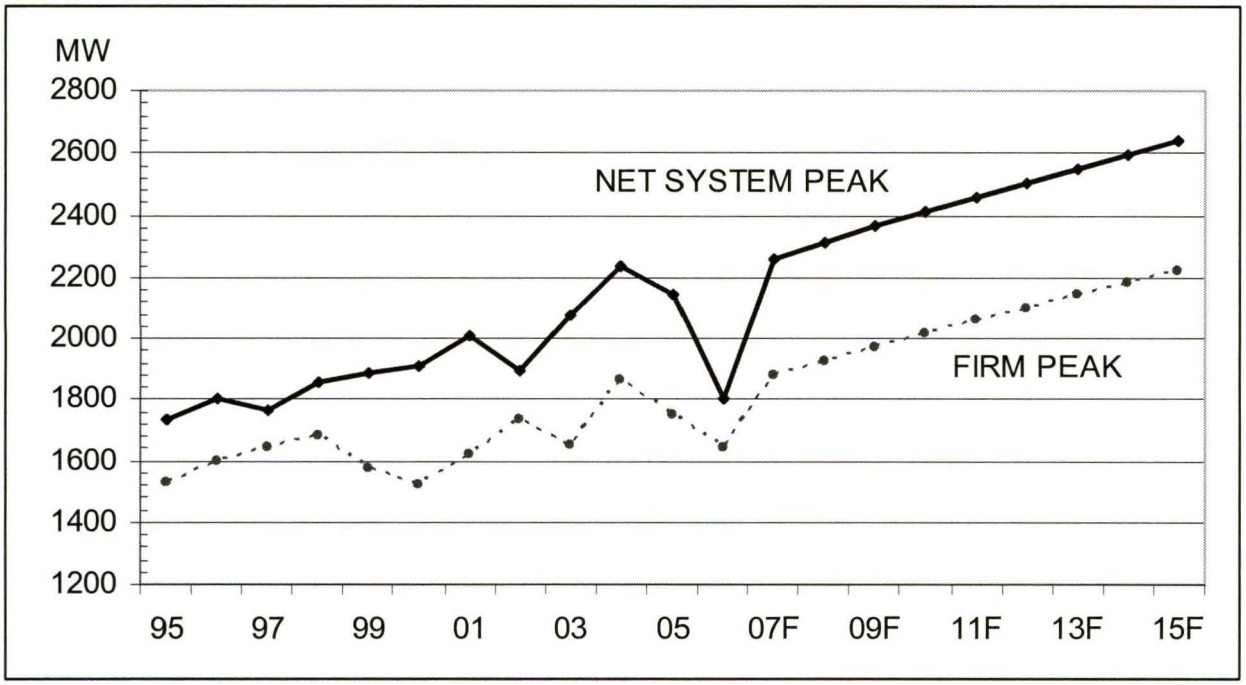


Figure B7: Net System Peak Demand and Firm Peak Demand



Appendix C

High and Low Forecast Scenarios

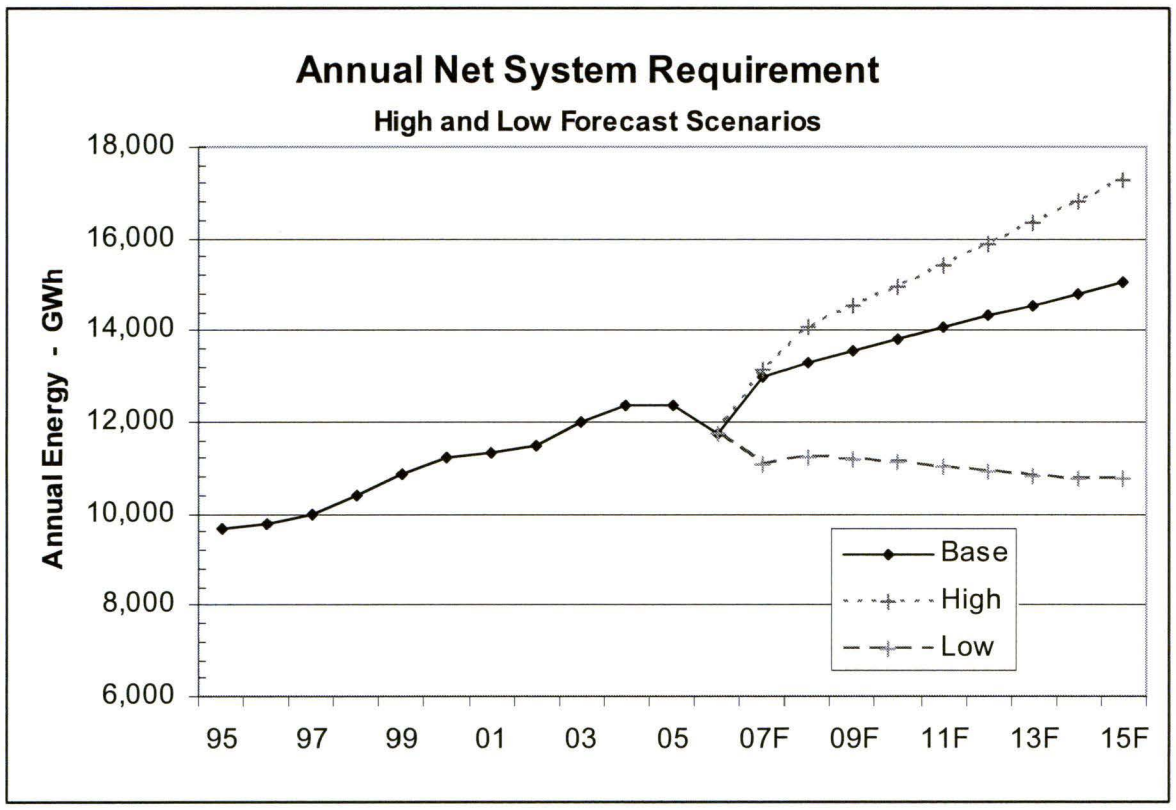
Appendix C: High and Low Forecast Scenarios

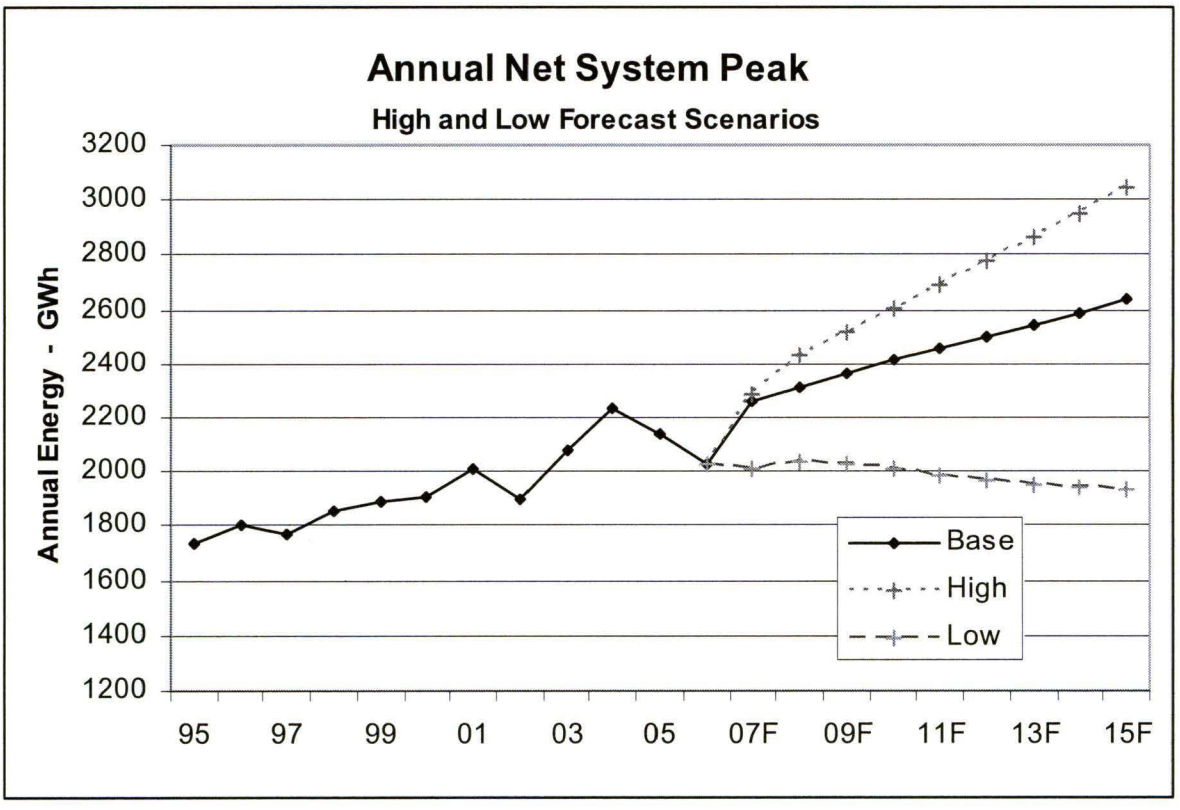
High and Low Forecast Scenarios

Low Forecast Scenario Assumptions	
1	*Major Paper Mill Closure (- 1,700 GWh /yr from 2007 onward)*
2	*Economic Growth Diminishes (Base case growth rate decreases by 50%)*
3	*45% reduction in home heating oil price in 2007*
4	*Electricity Price Increase (10% above base case)*
5	*Residential customer additions (base case reduced by 250/yr)*

High Forecast Scenario Assumptions	
1	New industrial load base added, +500 GWh/year, beginning in 2008
2	Economic Growth Improves (Base case growth rate increases 50%)
3	78% increase in home heating oil price in 2007
4	*Electricity Price decrease (10% below base case)*
5	Residential customer additions (base case +250/yr)

	Low		Base		High	
Year	NSR GWh	Peak MW	NSR GWh	Peak MW	NSR GWh	Peak MW
2007	11,084	2228	12,981	2,257	13,125	2,285
2008	11,210	2254	13,272	2,312	14,071	2,433
2009	11,184	2247	13,545	2,363	14,513	2,517
2010	11,100	2229	13,812	2,413	14,971	2,604
2011	10,998	2207	14,064	2,460	15,430	2,691
2012	10,904	2187	14,306	2,504	15,887	2,778
2013	10,828	2171	14,542	2,548	16,344	2,864
2014	10,772	2159	14,778	2,592	16,801	2,952
2015	10,752	2154	15,028	2,639	17,273	3,042


Annual Net System Requirement
High and Low Forecast Scenarios
Annual Energy - GWh
18,000
16,000
14,000
12,000
10,000
8,000
6,000
95
97
99
01
03
05
07F
09F
11F
13F
15F
Base
High
Low


Annual Net System Peak
High and Low Forecast Scenarios
Annual Energy - GWh
3200
3000
2800
2600
2400
2200
2000
1800
1600
1400
1200
95
97
99
01
03
05
07F
09F
11F
13F
15F
Base
High
Low

Appendix D

Forecast Sensitivity by Major Variable

Appendix D: Forecast Sensitivity by Major Variable

Forecast Sensitivity by Major Variable

Based upon the 2006 load forecast models, the following table shows the relative sensitivity of the forecast to changes in various input assumptions.

Variable	Assumed Change	Effect on 2007 Load GWh	Effect on 2011 Load GWh
Lagged Dependent Variable 2% growth on base year, 2005	Residential	27.2	2.2
	Commercial	18.7	1.3
	Industrial	9.7	3.0
	All	55.5	6.5
Retail Sales	+2%/yr (2006 on)	58.3	286.7
Gross Domestic Product	+2%/yr (2006 on)	55.3	273.3
Real Disposable Income	+2%/yr (2006 on)	17.8	79.8
Residential Electricity Price	+10% in 2006	-66.0	-97.1
Heating Degree-Days	+ 200 HDD/yr (2006 on)	68.0	112.9
Heating Oil Price	+10¢ per litre (2006 on)	10.0	69.7
Residential Customer Additions	+2000/yr (2006 on)	26.0	113.4

Note: This table portrays changes to individual variables only. In many cases, there are interdependencies that would require scenario development for more complete evaluation.