Public Service Company of New Hampshire

Least Cost Integrated Resource Plan

September 30, 2007

Public Service
of New Hampshire
The Northeast Utilities System
www.psnh.com

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I. Executive Summary

Public Service Company of New Hampshire's ("PSNH" or "the Company") 2007 Least Cost Integrated Resource Plan ("LCIRP") is filed pursuant to RSA 378:38. PSNH's previous LCIRP was filed in 2005.

A. Current Planning Environment

Since PSNH filed its previous LCIRP, the environment in which PSNH operates has undergone significant changes. There has been a movement toward a "greener" environment, while the cost of energy and generating capacity has continued to increase. PSNH has successfully completed and placed in service Northern Wood Power, but is unable to materially add to its renewable generating capacity due to State policy. Some of the more significant changes are listed below:

- On May 9, 2006, the Governor signed legislation into law requiring PSNH to cut mercury emissions by 80 percent by 2013 at its coal-fired power plants. As a result, PSNH is installing a scrubber at its Merrimack Station in Bow to achieve the reduction target.
- Climate change and global warming have become highly visible political issues nationwide resulting in a heightened awareness of the need for energy conservation and renewable energy sources.
- On June 16, 2006, the Federal Energy Regulatory Commission ("FERC") approved a newly designed Forward Capacity Market ("FCM") that replaced the Locational Installed Capacity Market ("LICAP"). A transitional capacity market design commenced in December 2006. The first FCM auction to procure capacity for the 2010-2011 Power Year is scheduled for February 2008. The initial show of interest includes 133 MW of demand resources and 42 MW of supply resources in New Hampshire.
- Overall energy costs have increased due to the rising cost of crude oil caused by supply problems in such places as Nigeria, Iraq and the Gulf of Mexico, as well as the threat of supply problems in Iran combined with refining problems due to the effect of devastating hurricanes like Hurricane Katrina in August 2005.
- PSNH experienced an increase in migration of large commercial and industrial customers to third party competitive suppliers due to a short-term drop in natural gas prices, making it more difficult to accurately forecast the amount of energy and capacity PSNH must purchase.
- In December 2006, Northern Wood Power, PSNH's conversion of a coal boiler to a 50 MW biomass (wood) boiler, went into service allowing PSNH to begin burning wood chips to produce electricity and selling Renewable Energy Certificates ("RECs") to suppliers in states with Renewable Portfolio Standard requirements.
- On May 11, 2007, the Governor signed into law the New Hampshire Renewable Portfolio Standard ("RPS") requiring utilities, including PSNH, to obtain up to 25 percent of their electricity from renewable power sources by 2025.
- During the 2006 and 2007 Legislative sessions, efforts to enable PSNH to expand its renewable generation ownership failed to pass.

- In 2007, legislation was enacted focusing on upgrading electricity transmission in the northern part of the state, expediting the site evaluation process for renewable energy generation projects, and requiring that the State Energy Policy Commission study demand response and the appropriateness of allowing electricity distribution companies to invest in generation.
- Congress enacted the Energy Policy Act of 2005. In 2007, the Commission began its consideration of various standards required by that law.

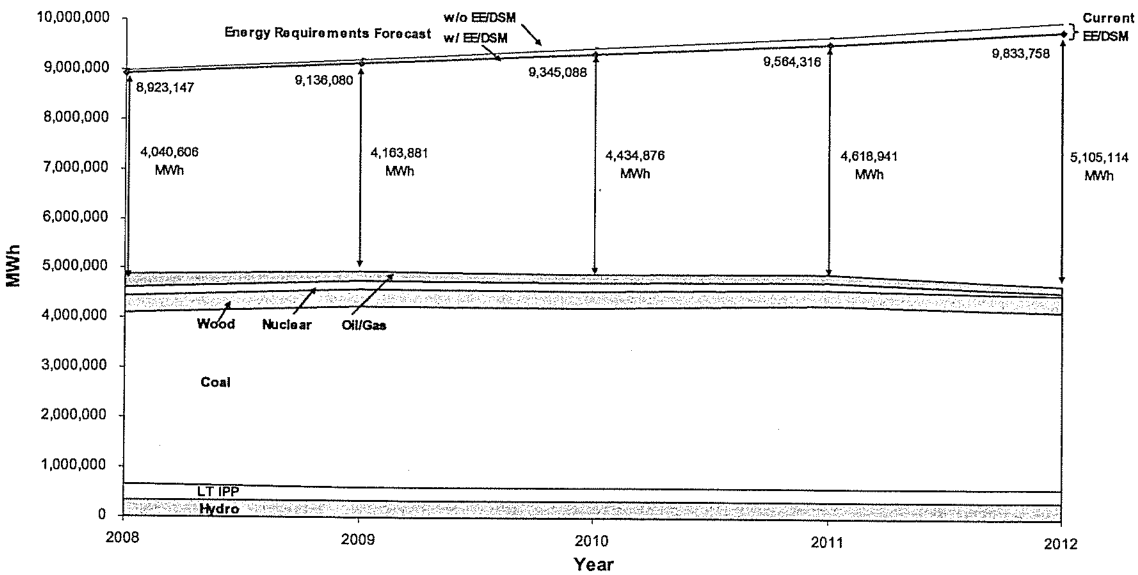
The events listed above highlight the changing environment in which PSNH operates and the challenges PSNH faces in planning due to the uncertainty that exists and the volatility of the underlying energy market. PSNH continues to monitor external events and provide input to legislators, regulators, policymakers and other stakeholders on shaping policies, regulations and rules. PSNH utilizes its supply resources, energy efficiency, and demand resources to meet increasing customer demand and highlights PSNH's involvement as it relates to ISO-New England, state, and industry initiatives.

B. Resource Needs

During the LCIRP planning period (2008-2012) PSNH customers' energy consumption is expected to grow about 2.3 percent per year while PSNH's system peak demand is expected to grow 2.5 percent per year. In addition, the newly enacted New Hampshire Renewable Portfolio Standard requires PSNH to supply a portion of its customers' energy requirements from renewable sources. PSNH's major generation resources are presently fixed due the absence of State policy regarding the expansion of utility ownership of regulated generation plants. As a result, PSNH will become more dependent on market power purchases to meet customer energy requirements, will be required to make additional capacity payments to ISO-New England due to PSNH's capacity deficiency, and will be required to either purchase Renewable Energy Certificates from qualified facilities or make Alternative Compliance Payments to the State of New Hampshire for the renewable resource deficiency.

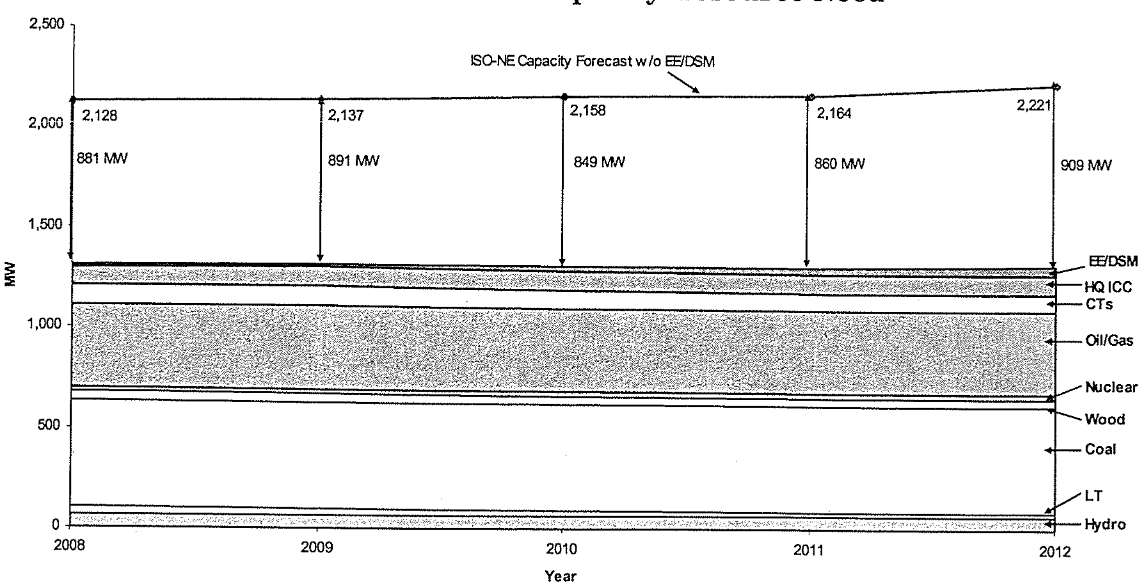
To meet the projected energy requirements, PSNH will need to purchase 4 to 5 million MWh annually in the open market over the planning period as shown by the vertical arrows in Exhibit I-1.

Exhibit I-1: PSNH's Energy Resource Need



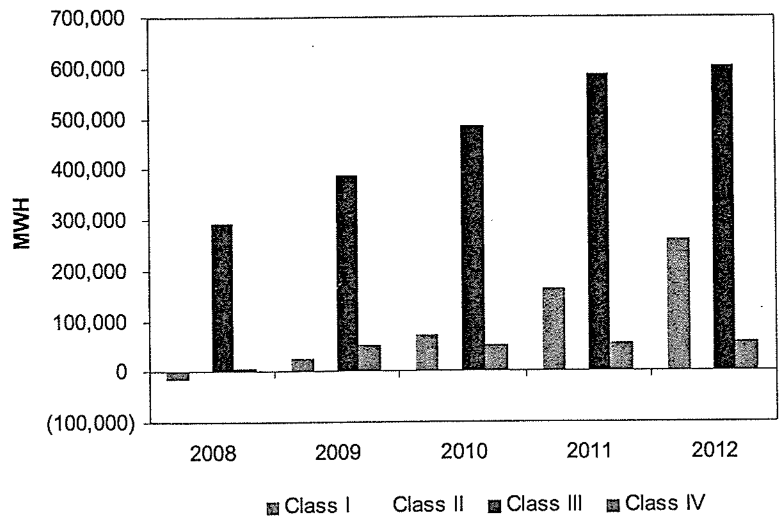
To meet PSNH's projected ISO-New England capacity requirement, between 900 and 1,000 MW of capacity will need to be procured annually over the planning period as shown by the vertical arrows in Exhibit I-2.

Exhibit I-2: PSNH's Capacity Resource Need



To meet the New Hampshire RPS requirements, PSNH will need to procure 261,000 MWh from Class I renewable resources, 13,000 MWh from Class II renewable resources, 601,000 MWh from Class III renewable resources, and 58,000 MWh from Class IV renewable resources to meet its RPS deficiency by 2012 as shown in Exhibit I-3.

Exhibit I-3: PSNH's Current Renewable Resource Need

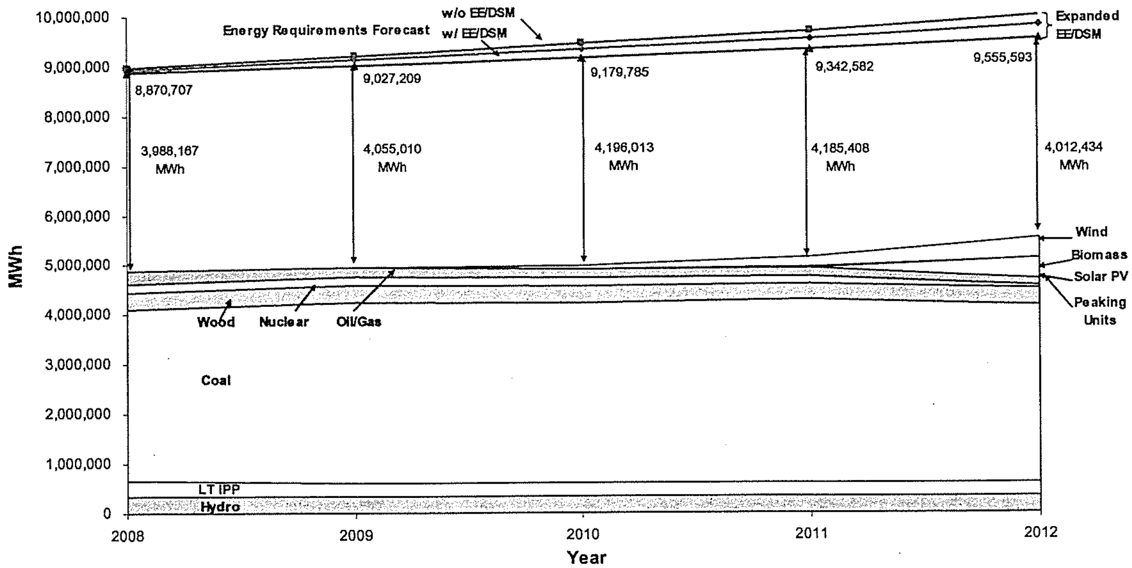


C. Meeting the Energy and Capacity Needs of PSNH's Customers

The projected resource gap described above can be met through purchases of energy in the open market, capacity payments to either ISO-New England or purchases of capacity through bilateral contracts, and purchases of Renewable Energy Certificates or Alternative Compliance Payments. However, in order to provide PSNH's customers with the lowest costs, PSNH analyzed adding a portfolio of PSNH-owned cost-of-service rate-based assets including at least one 50 MW biomass plant, up to three 20-25 MW distributed generation units to help meet peak load requirements, up to 12 MW of photovoltaic (solar) cells, up to six 24 MW wind projects, and increasing energy efficiency and demand-side programs. PSNH believes that this balanced portfolio of assets and load reductions keeps customers' best interests in mind, adds more renewable generation to New Hampshire, and is a lower cost alternative than purchasing the entire requirement need in the open market. Even with this portfolio, PSNH will still purchase a significant portion of its energy and capacity resource requirements from the market. Exhibits I-4, I-5, and I-6 below show the updated energy, capacity, and renewable portfolio requirements gap after factoring in PSNH's potential portfolio.

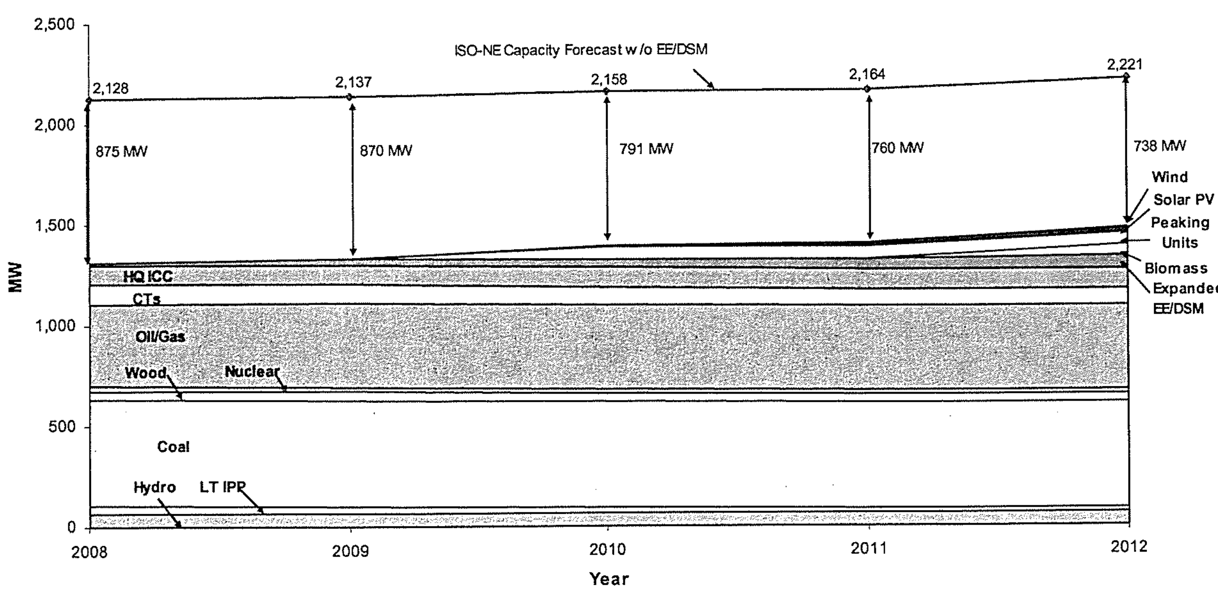
With the portfolio, PSNH anticipates reducing the market purchases from 4 to 5 million MWh to just less than 4 million MWh over the planning period as shown by the vertical arrows in Exhibit I-4.

Exhibit I-4: PSNH's Approach to Meeting the Energy Requirement Need



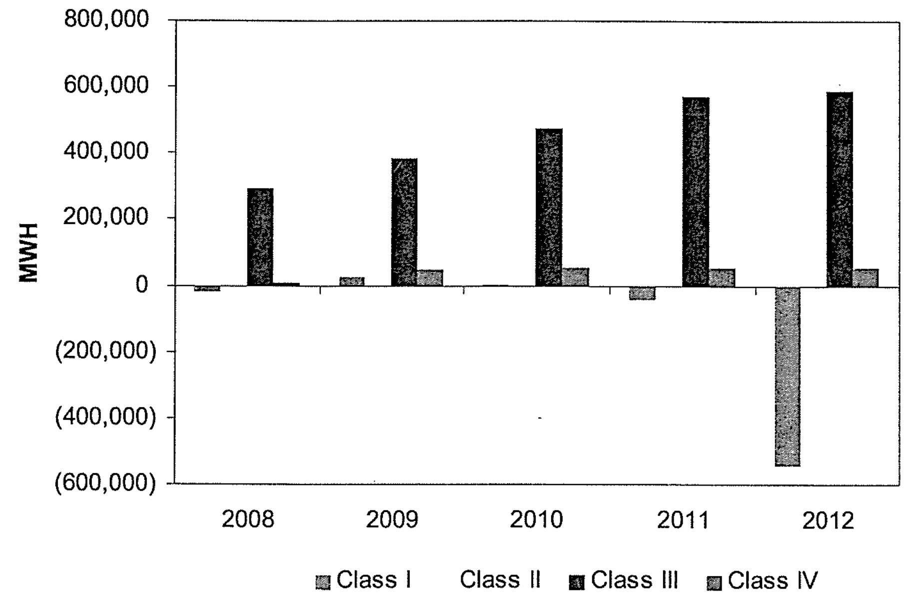
PSNH would also reduce the capacity purchases using this portfolio from about 900 MW in the final year of the planning period to just over 700 MW as shown by the vertical arrows in Exhibit I-5.

Exhibit I-5: PSNH's Approach to Meeting the Capacity Requirement Need



The portfolio would also reduce PSNH's renewable resource need to zero in Class II solar and would allow PSNH to sell additional RECs to other utilities from the additional Class I biomass MWh produced as shown in Exhibit I-6.

Exhibit I-6: PSNH's Renewable Portfolio Standard Need with Potential Portfolio



D. Conclusion

Continued ownership of generating units providing energy on a cost-of-service basis has allowed PSNH to maintain the lowest energy prices in New England. Despite the expectation of lower prices and new service offerings to customers through competition, prices in the region have not decreased as expected, and customers of utilities that divested their generating assets have observed the most significant price increases. Moreover, the new service offerings that were anticipated have not significantly materialized. A demonstration of the lack of new service offerings is the Commission's expressed interest in a docket to have regulated utilities implement advanced metering and time-based energy service pricing. Time-of-use pricing is an example of one of the new service options that was anticipated to possibly be offered by the competitive market, yet no such offering has materialized on a wide scale.

While PSNH's generation ownership keeps its energy prices relatively low, PSNH will be required to increase its purchases from the market in order to meet the energy needs of its customers, as well as to comply with renewable portfolio requirements. As the amount of energy, capacity, and renewable energy certificates purchased from the market increases, PSNH's energy service prices will correspondingly increase.

In order to maintain some price stability and to ensure that PSNH could provide energy at the lowest reasonable cost, PSNH would need the ability to add to its regulated generation fleet. This need is particularly acute in view of the recently enacted Renewable Portfolio

Standard, which creates a mandate for PSNH to meet a portion of its customers' needs with renewable resources. Absent the ability to construct new regulated generating units, PSNH's only option for meeting the requirements of the RPS are to purchase Renewable Energy Certificates from the market, or make an Alternative Compliance Payment. Under current State policy, PSNH is precluded from pursuing what could be its least cost option to meet customers' energy service requirements.

To remedy this situation, PSNH will continue to support the enactment of legislation that will allow it to add to its existing owned generation resources. By providing PSNH with all possible options for meeting the energy needs of its customers and complying with RPS requirements, policy makers can increase the likelihood that PSNH will be able to provide energy at the lowest reasonable cost.

E. Overview of LCIRP

A summary of the sections contained in the LCIRP filing are described below.

Introduction and Nature of the Plan: Provides an understanding of the environment in which PSNH operates and the role that PSNH plays in the current market.

Electrical Energy Demand Forecast: PSNH develops short-term and long-term energy and demand forecasts mainly for use in financial planning. This section describes the methodology and assumptions used to develop the delivery energy and peak demand forecasts and illustrates forecast scenarios based on high and low growth scenarios.

Assessment of Demand-Side Programs: PSNH is involved in conservation and load management ("C&LM") efforts through the CORE Energy Efficiency programs, a statewide energy efficiency program offered by each of New Hampshire's electric utilities. In addition to the CORE programs, PSNH offers several additional demand-side management programs including the Peak Smart and HEATSMART. ISO-New England also offers demand-side programs at the wholesale level.

Assessment of Supply Options: This section describes PSNH's existing generation supply resources including fossil fuel steam generating resources, fossil fuel combustion turbines, hydroelectric generating stations, biomass, purchased power contracts and Independent Power Producer ("IPP") contracts and rate orders. This section also discusses how PSNH meets its customers' energy requirements with a mix of owned resources and supplemental purchases.

Assessment of Transmission Requirements: ISO-New England is responsible for the coordination and planning of transmission in New England, including PSNH's transmission system.

Provision for Diversity of Supply Sources: PSNH's supply mix is diverse and includes coal, coal/oil, oil/natural gas, hydroelectric, biomass, Independent Power Producer contracts and rate orders and wholesale purchases. This supply diversity gives PSNH a flexible energy supply strategy.

Integration of Demand-Side and Supply-Side Options: Provides an analysis of a portfolio of supply side options in combination with demand side programs and identifies a combination of options that provides lower costs to customers compared to pure market purchases and is achievable given the constraints of the current environment.

Assessment of Plan Integration and Impact on State Compliance with the Clean Air Act Amendments of 1990: The federal Clean Air Act Amendments of 1990 established emissions goals for the electric power industry. PSNH has been proactively working to comply with these regulations using fuel switching and emissions allowance management strategies.

Compliance with the New Hampshire Renewable Portfolio Standard: The New Hampshire Legislature passed the Renewable Portfolio Standard requiring that a portion of PSNH's electricity supply come from renewable sources. This section describes the RPS requirements and PSNH's strategy for compliance.

Compliance with the National Energy Policy Act of 1992: The Energy Policy Act ("EPAct") of 1992 added certain provisions to the Public Utility Regulatory Policies Act ("PURPA") of 1978 standards which relate directly to integrated resource planning. This section describes PSNH's compliance with the EPAct in the areas of integrated resource planning and energy efficiency and demand-side management programs.

Assessment of the Plan's Long-and Short- Term Environmental, Economic and Energy Price and Supply Impact on the State: In addition to the Clean Air Act Amendments of 1990, there have been several federal and state environmental initiatives affecting PSNH's air emissions including sulfur dioxide (SO_2), nitrogen oxide (NOx), carbon dioxide (CO_2) and mercury (Hg). This section discusses the impact that current and potential federal and state regulations will have on PSNH and its customers.

II. Introduction and Nature of Plan

This section introduces PSNH's Least Cost Integrated Resource Plan filing, describes the regulatory background behind the filing and the current environment in which PSNH operates.

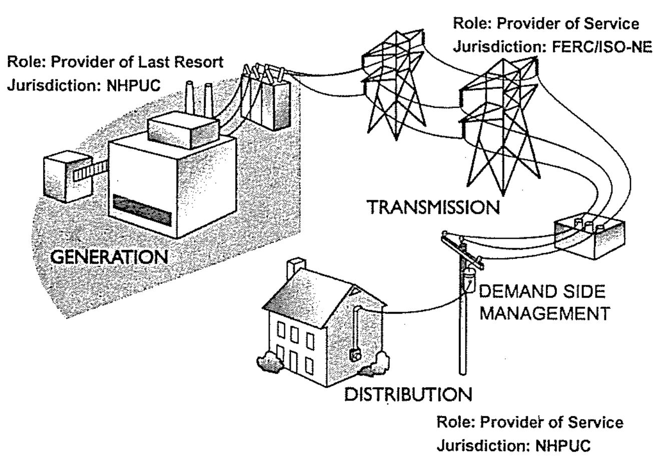
A. Regulatory Compliance

This plan is filed with the Commission in accordance with requirements established by New Hampshire RSA 378:38. Its content is consistent with the Partial Settlement Agreement approved by Order No. 24,695 dated November 8, 2006.

B. Role in Delivering Energy to Customers

Exhibit II-1 illustrates the current operating environment for delivering energy in New Hampshire and indicates the role that PSNH plays in each part of the energy delivery process and the authoritative body that has jurisdiction over each function.

Exhibit II-1: Energy Delivery Roles in New Hampshire



Due to the fact that PSNH owns a diverse generation portfolio, the total cost of electricity to our customers has been lower than other utilities in New England who have to procure their energy supply entirely in the open market. As seen in recent years, the market can be affected by a number of factors including geopolitical and weather-related events leading to high market prices all around. Generation ownership by PSNH has saved customers millions of dollars since the inception of restructuring. PSNH's objective in ownership of generation is to provide customers with reasonably priced energy service, thereby offering a measure of price discipline in an otherwise unpredictable marketplace while also ensuring customers may freely choose a competitive energy supplier. As can be seen in Exhibit II-2 below, PSNH's energy service rates are among the lowest in the region.

Exhibit II-2: New England Energy Service Rates
(in order of highest to lowest residential customer rate)

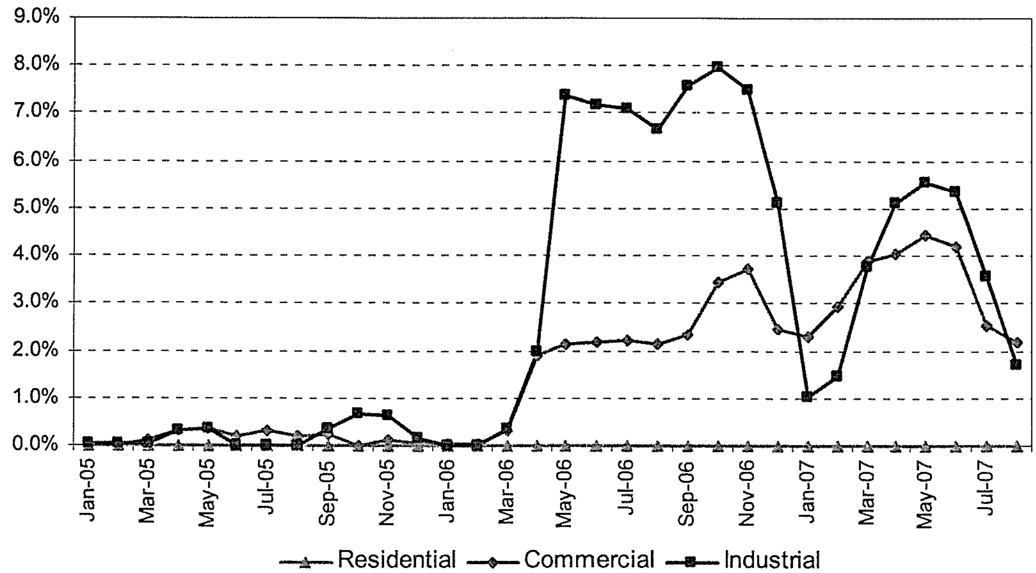
Utility Name	Residential (¢/kWh)	Small C&I	Large C&I	Effective Date
Unitil (MA)	12.3430	12.3660	MARKET	05/01/07
United Illuminating (CT)	11.9045	12.5090	12.7237	07/01/07
Connecticut Light & Power (CT)	11.6060	11.5570	12.1771	07/01/07
NSTAR (MA)	10.8380	11.0970	11.418 (NEMA) 10.804 (SEMA)	07/01/07
National Grid (MA)	10.2150	10.2870	10.508 (NEMA) 10.716 (SEMA) 10.221 (WCMA)	05/01/07, 08/01/07 (Lg)
Western Mass Electric (MA)	10.1840	10.9830	11.1590	07/01/07
Unitil Energy Systems Inc. (NH)	9.4310	9.4310	9.5123	05/01/07
Bangor-Hydro (ME)	9.0121	8.8270	10.3200	03/01/07
Central Maine Power (ME)	8.7994	8.7200	9.2550	03/01/07
National Grid (NH)	8.7770	8.7770	9.1090	05/01/07
New Hampshire Electric Co-op (NH)	8.6950	8.6950	8.7060	05/01/07
National Grid (RI)	8.3620	8.3620	8.3620	01/01/07
PSNH (NH)	7.8300	7.8300	7.8300	07/01/07

Source: PSNH analysis as of July 2007
Notes:
- The latest available published rate was used.
- Where on and off peak or variable pricing only exists, an average rate was calculated.

C. Competitive Environment

The competitive force of multiple suppliers vying to serve retail customers is the basis of the belief that competition will bring lower prices to retail customers in New Hampshire. PSNH continues to support customer choice in the competitive retail market. Over the past two years, the number of customers supplied by third party suppliers has increased as shown in Exhibit II-3 below. The increased migration activity occurs when near-term market conditions enable retail suppliers to offer contract options that are competitive with PSNH's energy service rate. Under current rules, migrated customers are free to return to PSNH's default service at any time. Customers choose the least cost option for them by comparing the PSNH's Energy Service rate to the market rate for energy supply.

Exhibit II-3: Percent of Load Served by Third Party Suppliers by Class



In addition to providing energy supply to its customers, PSNH, as a regulated utility, implements energy efficiency programs in accordance with public policy requirements, as directed by the Commission. Competitive energy suppliers and other contractors may also provide energy efficiency programs to electric retail customers; however, to date, PSNH remains the principal supplier of such services in its service territory.

D. Regional Energy Supply

At the time of the previous LCIRP filing, FERC issued a report estimating that ISO-New England would have a 20 percent summer reserve capacity margin[1], but that within New England there are load pockets that have insufficient generation to meet local needs and transmission constraints that prohibit the importation of generation from other areas. There are also areas with surplus generation locked in as a result of transmission constraints. ISO-New England predicted that capacity deficiencies would ultimately lead to load-shedding in the 2008-2010 time-frame absent significant changes to demand or supply.

Two years later, in 2007 ISO-New England now predicts that an additional 4,000 MW of generating capacity will be needed by 2016[2]. The newly created ISO-New England Forward Capacity Market is intended to provide an incentive to companies to build new supply resources or bid demand resources into the market to resolve the deficiency.

In addition, many states in New England have enacted Renewable Portfolio Standards which requires a certain percentage of total generation to come from renewable sources

[1] FERC's 2004 "State of the Markets Report" issued June 2005, page 83
[2] ISO-New England Presentation at the 31st Meeting of the Conference of New England Governors and Eastern Canadian Premiers, June 26, 2007 - http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2007/neg_ecp_6_26_07.pdf

(e.g., wind, solar, biomass, water). New Hampshire passed its own version of an RPS (2007 N.H. Laws, 26) that phases in the renewable requirements over a 17 year period.

E. Planning Under Uncertainty

Since the previous LCIRP was filed, the planning environment that PSNH operates in has undergone significant changes. Environmental requirements and transmission and capacity constraints have come to the forefront. The increased environmental requirements and ISO-New England mandated programs will increase costs to customers. PSNH is acutely aware of the additional costs that these programs place on customers and works to minimize the cost impact on customers by efficiently operating its generation facilities and promoting energy efficiency programs. In addition, PSNH looks for lower cost alternatives to keep up with customer demand and regulatory requirements.

PSNH undertakes short-term energy supply planning to provide customers who are not served by a competitive retail supplier with economic energy service. The Commission has approved PSNH's generation planning and operation during annual stranded cost reconciliation and energy service dockets. Additionally, PSNH has demonstrated cost effective planning through the construction and operation of Northern Wood Power at Schiller Station and the runner upgrade at Smith Hydro. These examples demonstrate PSNH's willingness to creatively prepare for the future energy supply of its customers, while being sensitive to market realities of cost and the environment while complying with State energy policy and regulations. PSNH was supportive of legislation to increase the amount of renewable energy and continues to work to educate and prepare interested parties on the impact that these requirements will have on our state's economy.

Uncertainty persists with regard to potential investment in generation assets. PSNH, like other generation owners, operates in a changing world, where future environmental regulations are likely to increase operating costs. Furthermore, markets for future fuel supply of oil and natural gas are highly volatile. In addition, coal prices and transportation costs have advanced as this generation fuel source takes on greater prominence, but such increases in coal and transportation may decline if increased environmental requirements reduce the use of coal. These variables and changes require PSNH to remain flexible in the operation of its generation assets. With so much changing so fast, the planning horizon has been shortened as compared to what was used in previous integrated resource planning. Due to the restrictions on expansion of generation ownership by PSNH, the Company has not planned on building or purchasing new generating capacity. However, to comply with the least cost planning process, PSNH developed a potential portfolio of supply options and energy efficiency and demand side management programs that could reduce the resource imbalance, resulting in less dependence on the volatile market if existing barriers were removed. This potential portfolio presents a reasonable list of options that PSNH could develop and provides customers with a lower cost option than solely purchasing energy from the market.

III. Electrical Energy Demand Forecast

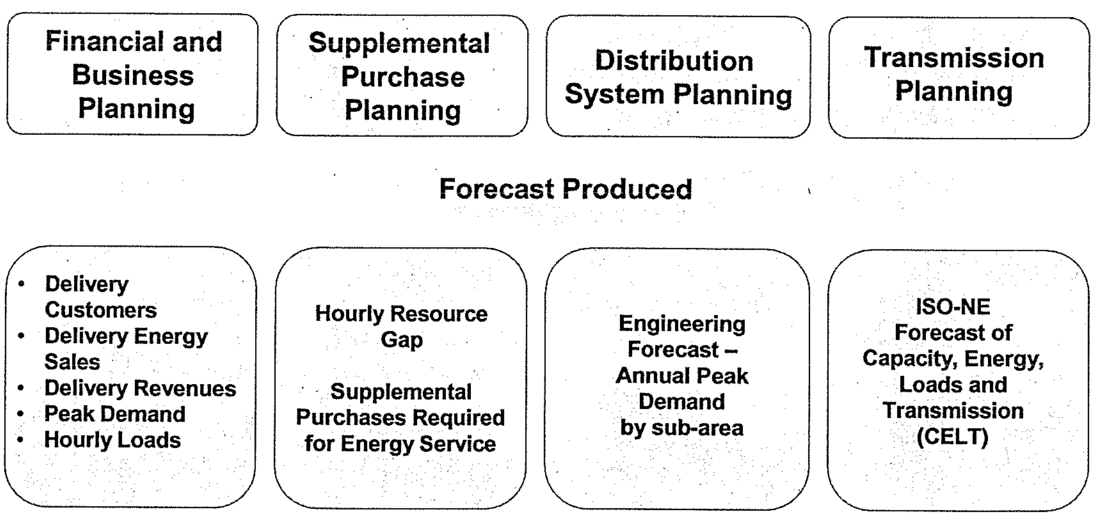
This section describes the process used for forecasting electrical energy and demand for use in long-term financial planning, supplemental energy purchasing planning, and capital planning. The methodology, assumptions and scenarios are discussed in the sections below.

A. Overview

PSNH uses four types of forecasts for different business purposes as shown below in Exhibit III-1:

- Financial and Business Planning: Customer, Delivery Energy Sales by Class, Peak Demand, and Hourly Load forecasts.
- Supplemental Energy Purchase Requirement Planning: Hourly load forecast, adjusted for customer migration or other forecast sensitivities, is used to develop the supplemental energy purchase requirement plan.
- Distribution System Planning: Engineering forecasts of the peak load by area for planning major capital projects affecting lines and substations.
- Transmission Planning: The ISO-New England has responsibility for regional transmission planning and develops its own forecast independently which is used by PSNH for its transmission planning. Refer to Attachment E for the Transmission Plan filed herewith.

Exhibit III-1: Forecast Types



B. Financial and Business Planning Forecasting

B.1. Overview

PSNH produces two types of forecasts used for financial and business planning:

- Short-term (1-2 year) energy forecast used for budgeting purposes
- Long-term (5 year) energy and peak demand forecast used for business planning purposes

PSNH does not utilize long-term forecasts greater than five years for financial and business planning purposes because of uncertainty in the market and the inherent inaccuracy of forecasts. The long-term forecast is reviewed and revised annually to recognize the volatility of even a five year forecast. The forecasts presented in this section describe the market conditions that PSNH anticipates assuming the existing regulatory climate as of March 2007 (the date the forecast was prepared).

The following sections describe the forecast methodologies and discuss the base case, high case and low case forecast scenarios.

B.2. Methodology

The following section provides a high level description of methodologies for the various types of forecasts that PSNH develops. For a more in depth discussion of the methodologies used, see Appendix A.

<u>**Customer Count Forecast**</u>

PSNH begins its forecast process with the development of a customer forecast. Econometric models are used to forecast customers by class, with customers as a function of an economic variable (households, non-manufacturing employment, or manufacturing employment).

<u>**Delivery Energy Sales Forecast**</u>

The next step in the forecasting process is the development of a Trend forecast and a Reference forecast for delivery energy sales. The Trend forecast is the starting point for the forecast development before any adjustments are made. The Reference forecast is equal to the Trend forecast adjusted for PSNH's Conservation & Load Management (C&LM), economic development programs, and projected net gains or losses resulting from large customer changes. These forecasts can also be described as "50/50" forecasts meaning that there is a 50 percent chance that the forecast will be exceeded. Both the Trend and the Reference forecasts assume normal weather conditions, are based on the total franchise area that PSNH serves, and represent all energy delivered to PSNH's retail customers. It is important to note what is included and excluded from the forecast.

The delivery energy sales forecast includes:
- Former CVEC customers beginning in 2004
- Customers of third party competitive suppliers
- Seabrook Station service

The delivery energy sales forecast does not include:
- Wholesale sales for resale and bulk power sales (Ashland, Wolfeboro, New Hampton, Unitil, New Hampshire Electric Co-operative and Central Maine Power customers served by PSNH's distribution system).
- Electrical losses

As a delivery company, changes in sales of Default Energy Service due to industry restructuring are irrelevant and are therefore not factored into the financial and business planning forecast. However, for supplemental purchase requirements planning, customer migration to third party suppliers is factored into the forecast used for that purpose, as discussed in section III.C.

Peak Demand Forecast

The next step in the forecasting process is the development of a Reference Peak Demand forecast. The highest hourly demand, which usually occurs during extremely hot or extremely cold weather, is referred to as the "peak demand." The purpose of the peak demand forecast is to develop the hourly energy forecast used for supplemental energy purchase requirements planning.

The Peak Demand forecast uses the totalized results from the Reference Delivery Energy Sales forecast described in the previous section as an input to the process. Additional inputs include weather and historical peaks for each month. The peak demand is also adjusted to include electrical losses estimated at 6.2 percent.

Hourly Energy Forecast

The hourly energy forecast is used as an input into the supplemental energy purchase forecast. To develop the hourly energy forecast, the monthly sales and monthly peaks are combined into an econometric model and the shape of the line is adjusted so that the hourly loads add up to the monthly energy from the Reference Delivery Energy Sales forecast and the highest hour matches the monthly peaks from the Reference Peak Demand forecast.

The hourly loads for each year include company use, wholesale requirements, and electrical losses and are divided by a delivery efficiency factor of 0.942 to convert into a pool transmission level. This is the base forecast of system electrical energy requirements or output and is the amount of energy which must be supplied by generating plants or power purchases to serve the loads on the system. For more detail on how the hourly forecast is used to make supplemental purchase requirements decisions, see section III.C.

B.3. Key Forecast Assumptions

Energy use forecasts for long-term planning purposes are based primarily on economic activity, price of electricity, projected efficiency improvements and saturation rates, weather, conservation and load management, and other key assumptions affecting energy usage. The sections below describe the major assumptions in greater detail.

B.3.1. Economic and Demographic Assumptions

PSNH utilizes national and state economic and demographics forecast models developed by Moody's Economy.com in the delivery energy sales forecast models. These forecasts are developed by Moody's Economy.com for base, high growth, and low growth scenarios. A national forecast of inflation, the implicit price deflator for gross domestic product (PGDP), is used to measure income and prices on an inflation adjusted basis. All other economic and demographic variables used in the forecast are for the state of New Hampshire. Exhibit III-2 shows the economic and demographic assumptions used in PSNH's forecast and the Compound Annual Growth Rate ("CAGR") from 2007 to 2012.

Exhibit III-2: Economic Outlook, 2007-2012 (Base Case)

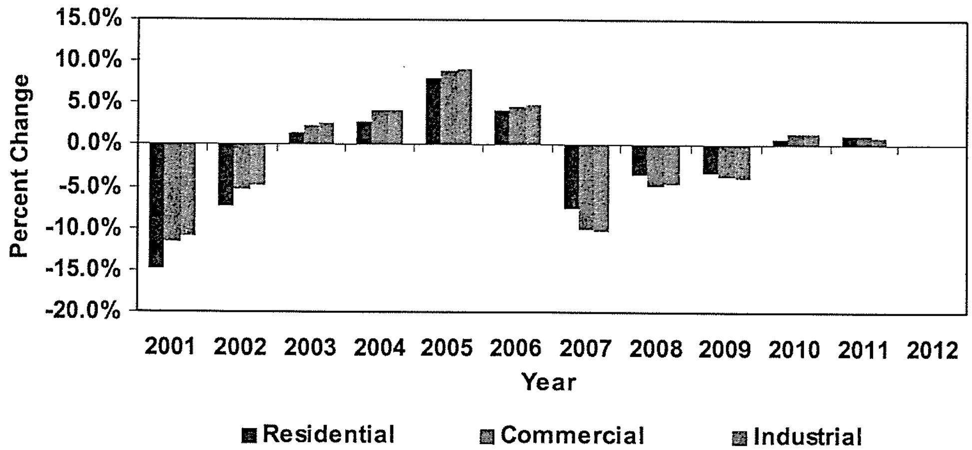
	2007	2008	2009	2010	2011	2012	CAGR
New Hampshire							
Personal Income (Mil)	$54,465	$57,595	$60,672	$63,780	$67,061	$70,525	5.3%
Real Personal Income ($2000 Mil)	$45,961	$47,468	$48,951	$50,440	$51,976	$53,622	3.1%
Population (Thous.)	1,328	1,344	1,358	1,371	1,385	1,401	1.1%
Housing Permits	4,234	4,460	4,405	4,437	4,582	4,826	2.7%
Households (Thous.)	513	521	528	535	543	551	1.4%
Non-Manufacturing Emp (Thous.)	571.5	580.7	589.5	598.5	607.7	618.0	1.6%
Manufacturing Emp (Thous.)	76.4	76.1	76.0	75.9	75.6	75.4	-0.3%
Service Producing Emp (Thous.)	538.8	547.9	556.5	565.2	573.8	583.6	1.6%
Non-Mfg Gross Product ($2000 Bil)	$44,275	$45,889	$47,515	$49,068	$50,622	$52,268	3.4%
Mfg Gross Product ($2000 Bil)	$7,692	$7,859	$8,021	$8,182	$8,324	$8,449	1.9%
Service Producing Gross State Product ($2000 Bil)	$42,006	$43,610	$45,222	$46,756	$48,272	$49,878	3.5%
United States							
Implicit Price Deflator for GDP	1.185	1.213	1.239	1.264	1.290	1.315	2.1%

Source: Moody's Economy.com, February 2007

B.3.2. Retail Energy Price Assumptions

The forecast for each of the major retail classes contains a price of electricity variable. Annual historic prices of electricity used in the model estimations are based on typical bills calculated from rate schedules by class of service. The forecast of electricity prices is based on current rate levels, revenue projections and cost of service for delivery rates. Prior to final analysis, all nominal electric prices are adjusted for inflation to provide real prices. Exhibit III-3 shows the real electric retail rate forecasts over the next five years for residential, commercial and industrial customer classes.

Exhibit III-3: Real Retail Electricity Prices, based on typical bills (Base Case)



Total delivery service is equal to the sum of the distribution, transmission, stranded cost recovery, system benefits, energy service, and consumption tax charges. The electric rate forecast assumes the following:

- Distribution Charge - Distribution rates reflect the rate levels on July 1, 2007, January 1, 2008, and July 1, 2008 in accordance with the DE 06-028 PSNH Rate Case Settlement Agreement. 2009-2012 rates assume annual rate increases to achieve a Cost of Capital ROE of 9.25 percent in 2009-2012.

- Transmission Charge - Transmission revenues are calculated reflecting the rate levels on July 1, 2007 in accordance with the DE 06-028 PSNH Rate Case Settlement Agreement, including the adoption of a Transmission Cost Adjustment Clause ("TCAM"). The approved settlement calls for annual TCAM adjustments that would incorporate the recovery/refund of the previous period's deferrals and projected costs for the upcoming calendar year, beginning January 1, 2008. Rates in 2009-2012 are adjusted to assume annual rate relief to fully recover transmission charges.

- Stranded Cost Recovery Charge ("SCRC") - SCRC rates are adjusted every year to fully recover the remaining securitized and ongoing non-securitized stranded costs (Part 1 and Part 2). The Stranded Cost Recovery Charge is expected to decrease in 2008 to 0.8 cents per kWh and remain constant throughout the forecast period.

- System Benefit Charge ("SBC") – Assumed to remain at the current level of 0.30 cents per kWh (consisting of 0.18 cents per kWh for C&LM and 0.12 cents per kWh for Low Income) as approved in the 2000 Restructuring Settlement.

- Consumption Tax Rate – Assumed to remain at the current level of 0.055 cents per kWh.

- Energy Service Rate – The Energy Service rate for 2007 is based upon the currently effective Energy Service rate, updated for current power market conditions as of February 14, 2007. The Energy Service rates for 2008-2012 are adjusted annually to reflect the forecasted energy and capacity cost from PSNH's owned generating assets and the projected market cost of purchasing additional energy to serve load. The Energy Service rate assumes 60-65 percent contribution of PSNH resources.

Additionally, high and low price scenarios were developed for use as inputs to the high and low forecast scenario analysis. The high price scenario is defined as a 10 percent price increase in 2008 and a constant real price in years 2009-2012. The high price is used in the Low Growth Case forecast since high prices generally indicate a weaker economy. The low price scenario is defined as a 10 percent price decrease in 2008 and a constant real price in years 2009-2012. The low price is used in the High Growth Case forecast since low prices generally indicate a stronger economy.

B.3.3. Conservation Savings Assumptions

Estimates of projected C&LM reductions are developed based on the current level of funding through the System Benefits Charge. The Trend Delivery Energy Sales forecast is directly adjusted for these projected sales losses. Exhibit III-4 lists the estimated MWh saved by class each year on a cumulative basis as a result of conservation and load management programs. It is assumed that there will be continued funding for existing C&LM programs throughout the forecast period.

Exhibit III-4: Conservation and Load Management

Cumulative C&LM Savings (MWh)						
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Residential	4,006	16,489	28,972	41,455	53,938	66,421
Commercial	3,729	15,067	26,405	37,744	49,082	60,420
Industrial	2,664	10,800	18,936	27,072	35,207	43,343
Streetlighting	0	0	0	0	0	0
Total	10,399	42,356	74,313	106,270	138,227	170,184

B.3.4. Other Key Assumptions

<u>Economic Development</u>

PSNH's Economic and Community Development department produces estimates of job gains or retentions as a direct result of economic development programs. An estimate of the additional MWh per class is developed using employment multipliers, an assumed average kWh per employee or customer, and an assumption on the percent of load due to economic development efforts already contained in the historical trend. Exhibit III-5 demonstrates the cumulative MWh effect of economic development programs. The Trend Delivery Energy Sales forecast is directly adjusted upward to account for the expected addition of load growth as a result of economic development programs.

Exhibit III-5: Economic Development

Cumulative Economic Development Adders (MWh)						
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Residential	370	1,065	1,760	2,455	3,150	3,845
Commercial	3,500	9,922	16,345	22,767	29,190	35,612
Industrial	2,606	7,306	12,005	16,705	21,404	26,104
Streetlighting	0	0	0	0	0	0
Total	6,476	18,293	30,110	41,927	53,744	65,561

Large Customer Changes

PSNH surveys its Account Executives to solicit field input on large accounts entering or leaving PSNH's service territory as well as anticipated changes in load usage of existing large accounts in the coming year. The Trend Delivery Energy Sales forecast is directly adjusted for the net result of sales as a result of large customer gains or losses.

Exhibit III-6 lists the estimated net MWh gained or lost by class each year on a cumulative basis due to changes in large customer usage. The forecast presented in this plan was adjusted to account for the losses associated with the closure of manufacturing facilities and expansions in hospital and office buildings.

Exhibit III-6: Large Customer Changes

Cumulative Large Customer Changes (MWh)						
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Residential	0	0	0	0	0	0
Commercial	5,550	12,000	12,000	12,000	12,000	12,000
Industrial	(17,545)	(27,746)	(27,746)	(27,746)	(27,746)	(27,746)
Streetlighting	0	0	0	0	0	0
Total	(11,995)	(15,746)	(15,746)	(15,746)	(15,746)	(15,746)

Self-Generation Losses

PSNH tracks customers that are planning to operate self-generation units and therefore will not be taking full service from PSNH in the near future. Self-generation customers normally become Rate B customers since PSNH must deliver and possibly supply the customer with default energy service when the self-generation unit is unable to meet the load demands of the customer. Estimates of the amount of load served by self-generation are developed from discussions between PSNH Account Executives and the customer. The Trend Delivery Energy Sales forecast is directly adjusted to exclude this self-generation from the forecast of PSNH delivery energy sales.

Exhibit III-7 lists the net estimated MWh provided each year on a cumulative basis due to self-generation operation. The current long-term forecast was adjusted for continuing amounts associated with a major university's self-generation and a wood pellet facility's move to self-generation in 2007.

Exhibit III-7: Self-Generation

Cumulative Self-Generation Deductions (MWh)						
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Residential	0	0	0	0	0	0
Commercial	(4,832)	(7,247)	(7,247)	(7,247)	(7,247)	(7,247)
Industrial	(2,381)	(8,094)	(8,094)	(8,094)	(8,094)	(8,094)
Streetlighting	0	0	0	0	0	0
Total	(7,212)	(15,341)	(15,341)	(15,341)	(15,341)	(15,341)

Generator Station Service

PSNH adjusts the Trend Delivery Energy Sales forecast to account for additional load provided to Seabrook Station during its refueling and maintenance outages. There is a specific adjustment for Seabrook Station load because of the large amount of energy delivered to the facility during a refueling and maintenance outage. PSNH does not adjust the Trend Delivery Energy Sales forecast for energy provided to other station service customers during generator outages due to their smaller size.

PSNH estimates the amount of additional load required for generation outages and adjusts the forecast to include additional sales expected as a result of increased station service requirements. Due to restrictions on public information related to specific generator outage schedules, the timing of planned outages at Seabrook are not known to the parties responsible for creating the PSNH forecast and therefore assumptions are made as to the timeframe and anticipated increase in load. Exhibit III-8 lists the additional load predicted as a result of Seabrook Station maintenance outages.

Exhibit III-8: Station Service Additions

Annual Station Service Additions (MWh)						
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Residential	0	0	0	0	0	0
Commercial	1,238	11,326	11,326	0	11,326	11,326
Industrial	0	0	0	0	0	0
Streetlighting	0	0	0	0	0	0
Total	1,238	11,326	11,326	0	11,326	11,326

Weather

PSNH bases its forecasts on normal weather defined as the thirty-year average (1977-2006) of heating and cooling degree days for the Concord, New Hampshire weather station. Historical actual billed sales are weather normalized using heating and cooling degree days as reported for the Concord, New Hampshire weather station. The Trend and Reference Delivery Energy Sales forecasts assume normal weather conditions.

Electrical Loss Factors

The electrical loss factor, expressed as a percent of sales, used in reporting PSNH system output is estimated at 6.2 percent for the distribution system. The electrical loss factors include distribution system losses but do not include transmission losses. Electrical loss factors are applied during the peak demand forecast development process.

B.4. Energy and Demand Forecasts

Delivery energy and demand forecasts for 2008 through 2012 form the basis of resource planning in this integrated resource plan.

The Reference forecast is a 50/50 forecast. Additional forecast scenarios were developed to model high and low economic and price conditions and are demonstrated in this section. PSNH analyzed three growth scenarios to capture sensitivities to the forecast associated with uncertain economic and price conditions. The customer forecast and energy delivery forecasts were developed using these scenarios. The impact of extreme weather on the peak demand forecast was also analyzed resulting in extreme weather scenarios based on a hot or cool summer and a cold or warm winter. These forecast scenarios provide sensitivities to the forecast and demonstrate the range of potential outcomes rather than a single reference forecast. Economic and price conditions are modeled for energy and weather is modeled for peak because general economic and price conditions have more of an impact on energy sales than peak demand whereas weather has the most impact on the peak day. Higher or lower economic conditions can change the delivery energy sales forecast by ± 2.5 percent whereas higher or lower weather conditions can change peak demand by ± 9 percent. The forecast scenarios modeled for energy and peak demand include:

- The Reference or Base Case forecast, which assumes that the New Hampshire and United States economies grow consistently and smoothly into the future with no disruptions. For the peak demand forecast, this case assumes normal weather conditions.

- The High Growth Case, which models good economic conditions and low energy prices and their impact on the customer and delivery energy sales forecasts.

- The Low Growth Case, which models weak economic conditions and high energy prices and their impact on the customer and delivery energy sales forecasts.

- The Extreme Weather Cases, which model extreme weather conditions (i.e., hot or cool summer and cold or warm winter) and their impact on the peak demand forecasts.

B.4.1. Customer Forecast

Exhibit III-9 graphs the customer forecasts for the Base Case, High Growth Case, and Low Growth Case scenarios over the planning horizon. The Base Case forecast shows a compound annual growth rate ("CAGR") of 2.3 percent whereas the Low Growth Case shows a 1.9 percent annual growth rate and the High Growth Case shows a growth rate of 2.7 percent. Higher or lower economic conditions can cause average annual growth to be 0.4 percent higher over the forecast period and can cause customers to be ± 0.7 percent in any year. See Appendix B for the detailed data behind the forecast scenarios.

Exhibit III-9: Customer Count Forecasts

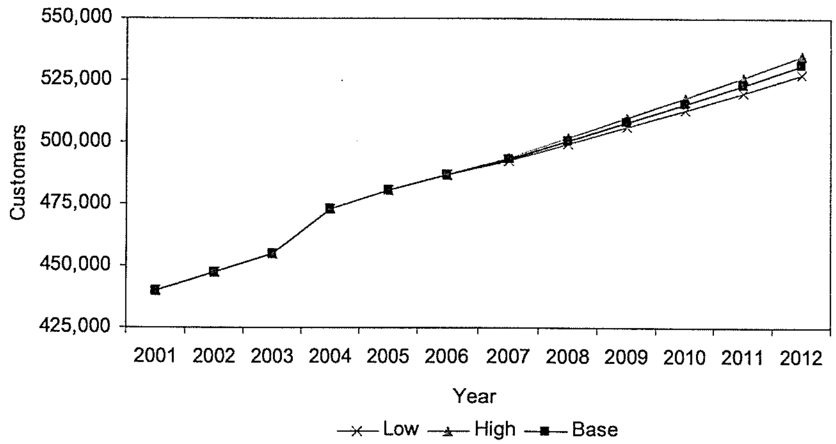


Exhibit III-10 below illustrates the Base Case forecast results by customer class. The 2002-2006 compound annual growth rate for total customers is 2.1 percent, compared to 1.5 percent over the 2006-2012 forecast period. The main reason for the decline in growth rates is due to the acquisition of CVEC assets on January 1, 2004. CVEC added about 10,000 customers to PSNH's system with the majority of those customers being residential. The acquisition of CVEC customers increased PSNH's total customer count by about 2.3 percent, causing the historical compound annual growth to look higher than it otherwise would have been. The forecast period returns to a consistent customer growth rate of around 1.5 percent.

Exhibit III-10: Customer Count History and Forecast (Base Case)

Annual Customer Counts										
Year	Res	% Chg	Com	% Chg	Ind	% Chg	St Light	% Chg	Total Retail	% Chg
History										
2002	382,481		61,775		2,818		509		447,583	
2003	388,133	1.5%	63,324	2.5%	2,758	-2.1%	523	2.7%	454,738	1.6%
2004*	403,088	3.9%	66,572	5.1%	2,783	0.9%	536	2.6%	472,979	4.0%
2005	408,959	1.5%	68,232	2.5%	2,768	-0.5%	563	4.9%	480,521	1.6%
2006	413,980	1.2%	69,528	1.9%	2,761	-0.3%	554	-1.6%	486,823	1.3%
Compound Annual Growth Rates (2002-2006)										
	2.0%		3.0%		-0.5%		2.1%		2.1%	
Forecast										
2007	419,430	1.3%	70,490	1.4%	2,763	0.1%	574	3.6%	493,258	1.3%
2008	425,522	1.5%	71,859	1.9%	2,757	-0.2%	583	1.6%	500,721	1.5%
2009	431,682	1.4%	73,081	1.7%	2,757	0.0%	593	1.7%	508,114	1.5%
2010	437,852	1.4%	74,229	1.6%	2,756	0.0%	603	1.7%	515,441	1.4%
2011	444,252	1.5%	75,337	1.5%	2,755	0.0%	613	1.6%	522,957	1.5%
2012	451,362	1.6%	76,475	1.5%	2,754	0.0%	623	1.6%	531,215	1.6%
Compound Annual Growth Rates (2006-2012)										
	1.5%		1.6%		0.0%		2.0%		1.5%	
* Acquisition of CVEC customers on January 1, 2004										

B.4.2. Delivery Energy Sales Forecast

Exhibit III-11 shows the Reference Delivery Energy Sales forecasts for the Base Case, High Growth Case, and Low Growth Case scenarios over the planning horizon. The Base Case has an average annual growth rate of 2.3 percent over the planning horizon while the Low Growth Case has an average annual growth rate of 1.9 percent and the High Growth Case has an average annual growth rate of 2.7 percent. Therefore, based on these specific scenarios, there is approximately a 0.4 percent band around the Base Case forecast as a result of economic and price variability. See Appendix B for the detailed data behind the forecast scenarios.

Exhibit III-11: Reference Delivery Energy Sales Forecasts

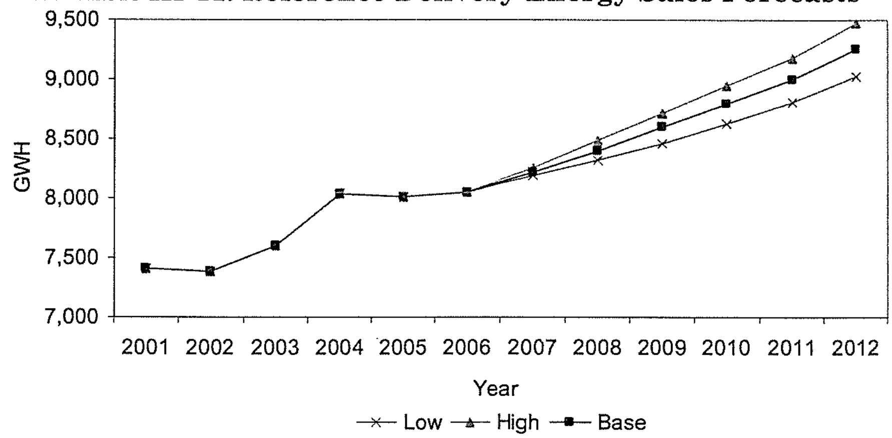


Exhibit III-12 below illustrates the Base Case forecast results by customer class, adjusted for PSNH's forecasted C&LM, economic development programs, and large customer changes. It does not include reductions due to ISO-New England's load response program. The Base Case forecast assumes normal weather based on a thirty-year average (1977-2006) of heating and cooling degree days, a base case economic forecast, and continued funding of C&LM and economic development programs.

The 2002-2006 compound annual growth rate for total delivery energy sales is 2.2 percent on a weather-normalized basis. The 2006-2012 compound annual growth rate for total delivery energy sales is 2.3 percent on a weather-normalized basis. Without PSNH's C&LM programs, the forecasted growth rate would be 2.7 percent. In 2004, PSNH added about 150,000 MWh of load due to the acquisition of CVEC assets, increasing sales by about 2 percent. In the forecast period, commercial sales are expected to continue to grow slightly faster than they have on average historically, industrial sales are expected to stabilize and residential sales are expected to grow at a slower pace than they have on average historically. During the historical period interest rates were low and home refinancing and home equity lines of credit were high and customers were increasing their living space and adding more electronic gadgets, increasing overall electricity use. The forecast period will return to consistent and stable sales growth and the increased interest in climate change will likely result in increased conservation efforts.

Exhibit III-12: Annual Reference Delivery Energy Sales (Base Case)

Annual Reference Delivery Energy Sales (GWH)											
Year	Res Sales	% Chg	Com Sales	% Chg	Ind Sales	% Chg	St Light Sales	% Chg	Total Retail Sales	% Chg
History (Weather Normalized)										
2002	2,771		2,958		1,634		23		7,386	
2003	2,880	3.9%	3,045	2.9%	1,659	1.5%	23	0.6%	7,607	3.0%
2004*	3,036	5.4%	3,251	6.8%	1,723	3.9%	25	4.8%	8,034	5.6%
2005	3,102	2.2%	3,296	1.4%	1,592	-7.6%	24	-0.5%	8,014	-0.2%
2006	3,118	0.5%	3,341	1.4%	1,574	-1.1%	23	-5.4%	8,057	0.5%
Compound Annual Growth Rates (2002-2006)										
	3.0%		3.1%		-0.9%		-0.2%		2.2%	
Forecast										
2007	3,185	2.1%	3,427	2.6%	1,584	0.7%	25	6.3%	8,222	2.0%
2008	3,229	1.4%	3,564	4.0%	1,585	0.0%	25	1.1%	8,402	2.2%
2009	3,298	2.1%	3,681	3.3%	1,599	0.9%	25	0.8%	8,603	2.4%
2010	3,375	2.3%	3,788	2.9%	1,612	0.8%	25	0.8%	8,799	2.3%
2011	3,458	2.5%	3,913	3.3%	1,610	-0.1%	25	0.8%	9,006	2.3%
2012	3,559	2.9%	4,049	3.5%	1,626	1.0%	26	0.9%	9,260	2.8%
Compound Annual Growth Rates (2006-2012)										
	2.2%		3.3%		0.5%		1.8%		2.3%	
* Acquisition of CVEC customers on January 1, 2004										

Exhibit III-13 shows the adjustments made to the Trend forecast to arrive at the Reference forecast.

Exhibit III-13: Annual Delivery Energy Sales Forecast Buildup, 2007-2012

Annual Delivery Energy Sales Forecast Buildup (GWH)							
	Trend	C&LM	Economic Development	Large C&I	Station Service	Company Use	Reference
2007	8,243	8,233	8,250	8,224	8,245	8,243	8,222
2008	8,446	8,404	8,464	8,415	8,457	8,446	8,402
2009	8,667	8,592	8,697	8,636	8,678	8,667	8,603
2010	8,895	8,789	8,937	8,864	8,895	8,895	8,799
2011	9,110	8,972	9,164	9,079	9,121	9,110	9,006
2012	9,384	9,214	9,450	9,353	9,395	9,384	9,260

B.4.3. Peak Demand Forecast

Exhibit III-14 shows the Peak Demand actual history and weather normalized forecasts for the Base Case and Extreme Weather Case scenarios over the planning horizon. See Appendix B for the detailed data for the Weather Scenarios.

For the summer peaks, the Base Case has a compound annual normalized growth rate of 2.1 percent over the planning horizon while the Extreme Cool Case has a compound annual growth rate of 0.5 percent and the Extreme Hot Case has a growth rate of 3.7 percent.

For the winter peaks, the Base Case has a compound annual normalized growth rate of 1.3 percent over the planning horizon while the Extreme Cold Case has a compound annual growth rate of 2.2 percent and the Extreme Warm Case has a growth rate of -0.2 percent.

These weather scenarios show that the variability of peak demand due to extreme weather conditions in the summer is ± 8 to 9 percent. This results in about 140-170 MW of additional load in the summer due to extreme weather conditions.

Exhibit III-14: Peak Demand Forecasts
Actual 2002-2006 and Forecast 2007-2012

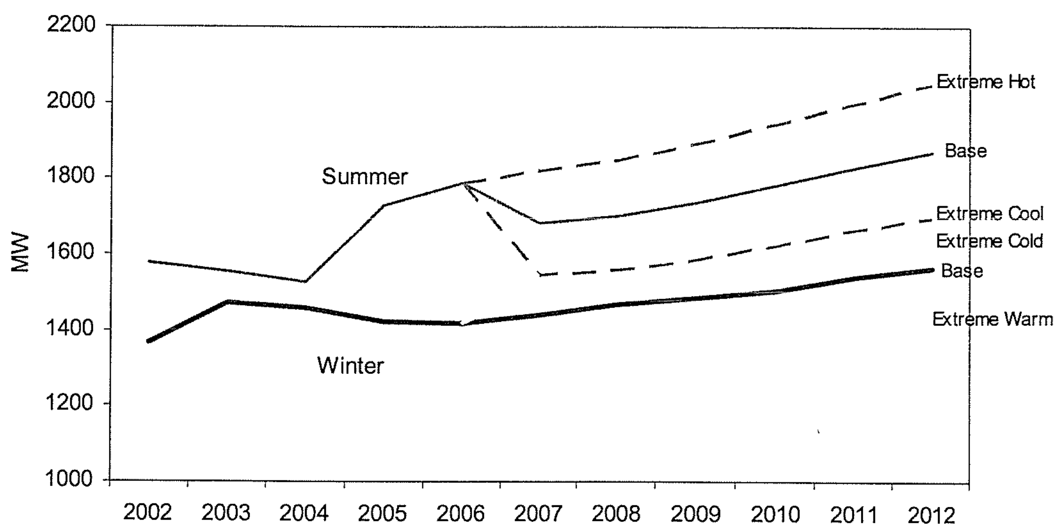


Exhibit III-15 below provides historic output and summer and winter peaks, normalized for weather. The 2002-2006 compound annual growth rate for peak demand is 2.3 percent in the summer and 0.7 percent in the winter on a weather-normalized basis. The 2006-2012 compound annual growth rate for peak demand is 2.1 percent in the summer and 1.3 percent in the winter on a weather-normalized basis. This table demonstrates that energy and peaks don't necessarily follow the same growth path. Weather and air conditioner use are the main drivers for growth in peak demands during the summer.

Exhibit III-15: Annual Output and Peak Load, 2002-2012 (Base Case)

	Output (GWh)	% Chg	Summer (MW)	% Chg	Winter (MW)	% Chg
History (Not Weather Normalized)						
2002	7,968		1,575		1,365	
2003	8,249	3.5%	1,556	-1.2%	1,471	7.8%
2004	8,495	3.0%	1,525	-2.0%	1,458	-0.8%
2005	8,655	1.9%	1,729	13.4%	1,419	-2.7%
2006	8,489	-1.9%	1,786	3.3%	1,418	-0.1%
Compound Annual Growth Rate (2002-2006)						
	1.6%		3.2%		1.0%	
History (Weather Normalized)						
2002	7,950		1,508		1,401	
2003	8,157	2.6%	1,498	-0.7%	1,405	0.3%
2004	8,539	4.7%	1,552	3.6%	1,518	8.1%
2005	8,529	-0.1%	1,670	7.6%	1,419	-6.5%
2006	8,511	-0.2%	1,650	-1.2%	1,442	1.6%
Compound Annual Growth Rate (2002-2006)						
	1.7%		2.3%		0.7%	
Forecast						
2007	8,731	2.9%	1,682	-5.8%	1,440	1.6%
2008	8,923	2.2%	1,702	1.2%	1,465	1.7%
2009	9,136	2.4%	1,738	2.1%	1,484	1.3%
2010	9,345	2.3%	1,781	2.5%	1,502	1.2%
2011	9,564	2.3%	1,828	2.6%	1,542	2.6%
2012	9,834	2.8%	1,870	2.3%	1,561	1.3%
Compound Annual Growth Rate (2006-2012)						
	2.5%		0.8%		1.6%	
Normalized Compound Annual Growth Rate (2006-2012)						
	2.4%		2.1%		1.3%	

B.4.4. Delivery Hourly Load Forecast

The Delivery Hourly forecast combines the Delivery Energy Sales forecast and the Peak Demand forecast to produce hourly values for use as a base forecast for supplemental purchase requirement planning. In addition to the Base Case, the High Growth Case and Low Growth Case for Delivery Energy Sales and the Extreme Weather Cases for Peak Demand are provided to show the sensitivities to the forecast. A delivery sales hourly load forecast is developed as a final step in the financial and business planning forecasting process and is the base forecast used in the Supplemental Purchase Requirement forecasting process.

C. Supplemental Purchase Requirement Forecasting

C.1. Overview

The Supplemental Purchase Requirement forecast is used to determine the resource gap and required purchases needed to fill the resource gap. The Supplemental Purchase Requirement forecast is further refined throughout the year as more accurate planning information becomes available. This refined forecast ultimately is filed with the Commission during the Energy Service ("ES") rate setting proceeding.

C.2. Methodology and Assumptions

PSNH's Supplemental Purchase Requirement forecast incorporates customer migration, forecast sensitivities, planned generation outages, forced outages, forecasted dispatch patterns for the fossil units, and assumptions for hydroelectric and IPP production. These assumptions are discussed in further detail below.

C.2.1. Customer Migration and Forecast Sensitivity

PSNH is required to serve all customers who do not select a competitive supply option. Current rules permit customers to move without limitation between competitive supply and PSNH's Energy Service as often as every billing cycle. The base Delivery Hourly Load forecast assumes no customer migration to competitive retail supply; therefore, the Supplemental Purchase Requirement forecast must be adjusted to account for customer migration. In prior mid-year ES rate adjustment proceedings, PSNH has assumed a quantity of migration consistent with recent history (see Dockets DE 06-125 and DE 05-164). Additionally, the sensitivities resulting from the high and low growth and extreme weather forecast scenario analyses are taken into account when making adjustments to the Supplemental Purchase Requirement forecast

C.2.2. Planned Generation Outages

Planned generation outages are based on the latest available maintenance schedule.

C.2.3. Forced Outages

Between planned maintenance periods, a unique forced outage factor is applied to the full capability of each Schiller and Merrimack unit. This factor is based on historical performance, as modified to account for any anticipated, atypical operating conditions. Newington Station is assumed to be capable of its full claimed capacity between maintenance outages. Forced outages at the hydroelectric facilities are generically addressed by forecasting operation at the 20-year historical monthly average.

C.2.4. Forecasted Dispatch Patterns for the Fossil Units

Fossil unit dispatch pattern assumptions are based on economic and operational considerations. For each major fossil unit (Schiller, Merrimack, and Newington), the anticipated per unit fuel expense (i.e., $/ton of delivered coal and wood or $/bbl of delivered oil), plus variable O&M and emission adders, is converted into a $/MWh equivalent. This "dispatch price" is compared with the anticipated market price for power to determine the periods when the units will be economically dispatched. In general, the coal-fired and wood-fired units (Merrimack and Schiller) are economic in all periods and, thus, are assumed to operate as baseload resources outside of planned maintenance periods. Newington is generally dispatched in the more expensive months, e.g. winter and summer, and is assumed to be in reserve for use in the remaining months. The combustion turbines are always assumed to be in reserve to respond to short duration price spikes that exceed the average fuel and variable O&M expense of the unit.

C.2.5. Hydroelectric and IPP Production

Hydroelectric production is assumed to be consistent with the 20-year historical average. IPP production is based on long-term historical averages.

C.3. Supplemental Purchase Requirement Forecast and Planning

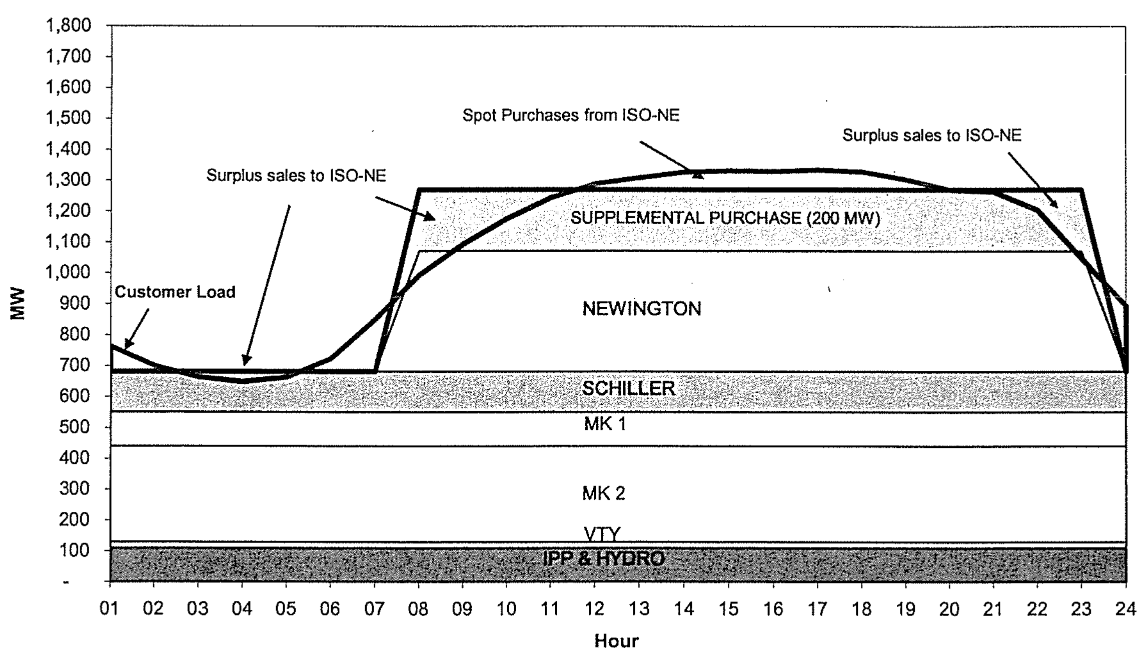
The hourly load forecast is converted into a supplemental purchase forecast that varies hourly according to the load and resource balance. The purchase requirement changes hourly and can range from zero to a significant portion of total requirements, depending on the availability of PSNH's resources, the level of demand, the migration of customers to competitive energy service options, and the relative economics of PSNH's generation versus purchase alternatives. The hourly quantities are converted into monthly averages by time-of-use (e.g., on-peak and off-peak periods). In this manner, PSNH identifies a targeted set of block purchases that, on a volumetric basis, serves a quantity of load approximately equal to the sum of the hourly purchase requirement identified in the planning forecast. The volumetric approach converts a quantity that varies hourly into an average volume that can be procured via standardized bilateral contracts. PSNH's supplemental purchase procurement strategy is discussed further in Section V.

Long-term energy supply planning is further refined and/or supplemented by monthly, weekly, and daily planning. Prior to the start of a given month, PSNH will review current load forecasts that account for any customer migration to competitive supply. Also, any known changes to planned generation maintenance schedules will be reviewed. Given the particular flexibility and fuel diversity of PSNH's Newington Station, the economics of this unit are closely monitored to ensure that the unit is operated in a manner that optimizes the fuel usage and incorporates operational consideration such as emission control, minimum down times, minimum run times, ramp rates, etc. For example, if replacement power contracts can be executed at a price that is less than the dispatch price of Newington, it may be possible to place the unit on economic reserve. A similar type of review is conducted prior to the start of each week.

PSNH's supplemental purchase requirement is heavily influenced by the economics of Newington. When Newington's fuel expense is lower than the cost of purchasing power, the unit is dispatched and PSNH's supplemental need is significantly reduced. During on-peak hours, when PSNH's baseload and intermediate resources (including Newington) are dispatched, PSNH requires supplemental purchases that range from zero (during low load months) to approximately 400 MW (during high load months). Typically, Newington is not economic for dispatch during the off-peak hours (weekends, holidays, and weekdays during hours 1-7 and 24). The resulting off-peak purchase requirement will range from zero to 400 MW. Forced and planned outages increase the need for supplemental purchases.

On a daily basis, PSNH forecasts the hourly load and supply resource distribution for the following day. This process incorporates updated information on weather and load patterns, fossil unit availability, Newington status, hydroelectric and IPP production forecasts and existing power purchases. The daily forecast determines the anticipated level of energy obligation that is not being served at a known price, i.e. the ISO-New England spot purchase exposure. PSNH reviews this exposure and, if required, executes additional bilateral purchases (PSNH's daily spot market risk policy is to limit daily spot exposure to 15 percent of the on-peak energy requirement and 30 percent of the off-peak requirement). Typically, and by necessity, a small portion of PSNH's energy obligation is procured via the ISO-New England spot market. Also, each day normally includes a number of hours in which PSNH has surplus supply that is sold into the ISO-New England spot market. To illustrate this interaction with the ISO-New England spot market, Exhibit III-16 depicts PSNH's typical summer daily energy position.

Exhibit III-16: PSNH Typical Summer Daily Energy Position



D. Distribution System Planning Engineering Forecasting

D.1. Overview

The planning for capital expansion of the distribution system relies on data from an Engineering Forecast ("EF") for peak demand. As the first step of the planning process PSNH's distribution System Planning Department provides an EF for the overall system and also by geographic areas. The current methodology for forecasting is based on historical data analysis and incorporates econometrics and weather normalization. The EF is reviewed annually and updated based on actual data.

Ultimately, the distribution system must be capable of serving the peak load experienced and, therefore, a forecast methodology which results in construction recommendations at the appropriate future dates is important. A model that under-forecasts capital investment requirements will limit system capabilities during peak load periods whereas a model that over-forecasts capital investment requirements will result in construction of facilities well before they are required. However, any model to forecast the future will invariably yield an estimate which is different from actual experience. It is important to note that the planning horizon for a transmission system is typically longer than for a distribution system and there are different reliability criteria. The shorter planning and construction period for distribution systems provides increased opportunity to modify plans as circumstances change.

D.2. Methodology

The first step in the EF development is identifying actual historical peak demands. PSNH records system peak load based on the highest single hour of demand as measured simultaneously at many points across PSNH's system and accumulated at the Electric System Control Center ("ESCC"). The current system peak is then used to calculate the compounded growth rate for the system and in each of the 12 geographical areas. Each area represents localized distribution systems and allows an in-depth examination of the peak demand growth specific to that discrete area. Factors that influence a planning area are likely to be similar throughout the area, such as weather, economic activity, and customer profile (i.e., number of residential, small commercial and industrial customers). Each area is modeled as electrically separate which allows for load and peak demand growth assumptions to be matched with the specific distribution system construction needs appropriate for the area.

Exhibit III-17 shows the EF growth rates by area. It is based on historical peak data and the compounded growth rates for the years 1994-2006 and ten years of forecast data.

Exhibit III-17: PSNH Summer Peak Load Forecast by Area

Area	2006 Summer Peak (MW)	Compound Annual Growth Rate (%) Historical (1994-2006)	Forecast (2008-2018)
Lakes Region	190.6	4.32	4.30
Derry	132.1	5.95	6.00
Dover/Rochester	169.1	3.17	3.00
Manchester	363.2	4.00	4.00
Sunapee	40.3	2.28	2.00
Berlin/Lancaster	68.7	0.17	0.50
Portsmouth	267.5	5.64	5.50
Nashua	408.1	2.64	2.70
Western	168.0	3.71	3.70
Ossipee	72.7	3.34	3.40
Seacoast	164.3	4.38	*
Concord	134.6	3.28	*
PSNH System **	**1918.3**	**3.31**	**3.40**

*Unitil provides load data for these areas utilizing its forecast methodology.
** PSNH System data includes NHEC and municipal load fed at the distribution level.

D.3. Planning Use of the Engineering Forecast

System planning is performed for PSNH's main 34.5kV distribution system by incorporating the EF loads into a computer model. The capital investment needs are identified in the three- and ten- year loadflow system studies based on PSNH's ED-3002 Distribution System Planning and Design Criteria Guidelines. This guideline addresses several issues of importance in planning for growth. It provides long-term solutions incorporating issues such as good engineering design, reliability, power quality, and operating strategies. The intention is that this is the backbone document for a least cost plan for capital investments on the distribution system.

A three-year loadflow study is used for short term planning and budgeting. In this study major substation and line additions and their needed in-service dates are clearly defined for the next three budget years. The forecasted load levels for this period are reasonably accurate based on the above described EF process. For example, the study identifying major capital investments for 2008-2010 was completed in 2007.

A ten-year study provides a long-term EF and capital investment strategy. The report produced under this planning process includes the major construction items required for the next ten years. The construction requirements after the first few years become less firm and are subject to delay or acceleration of in-service dates based on the actual growth.

D.4. Planning by Area

The construction requirements for the electrical system are based on each area's load growth and the area EF. Some areas experience peak demand growth rates of more than 5 percent while others see essentially no peak load growth or even a reduction in peak load.

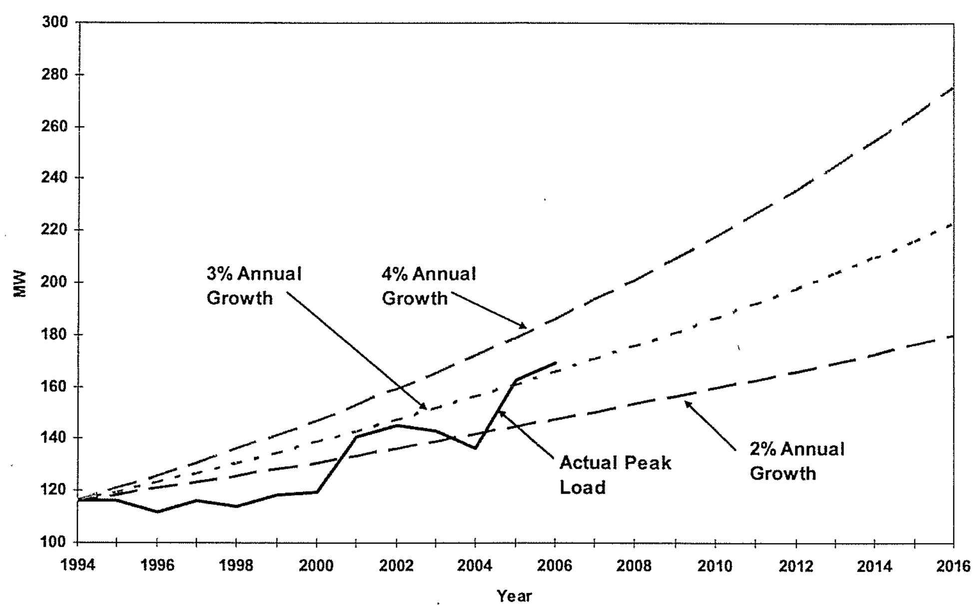
Since distribution capacity is required where the load growth is located, the planning process generally results in total system capital investment requirements that exceed what would be required if planning was simply performed based on PSNH's total system load growth. The summer peak demand history by area is in Appendix C. Specific examples of this investment by area need are shown in Exhibits III-18 and III-19 below with the descriptions of the areas.

D.4.1. Dover/Rochester Area

As demonstrated in Exhibit III-18 below, this area has had a sharp increase in load since the summer of 2000. This is typically indicative of air conditioning load in residential areas. Additionally, the strong economy makes window air conditioners affordable for almost all households. The 3 percent growth rate curves for 2001, 2002, 2005, and 2006 match the 3 percent compounded peak growth rate curve closely. These summers all had heat waves with multiple consecutive 90 degree days. The 10-year historical compounded summer growth rate is 3.2 percent while the winter growth rate is 2.0 percent for this area. The EF for this area is 3 percent.

The Dover/Rochester Area is normally fed by approximately 180 MW of 115-34.5kV transformer capacity. The 2006 peak demand for this area was 170 MW. In order to serve the peak demand in this area, additional capacity is required by 2009.

Exhibit III-18: Dover/Rochester Area Summer Peak Load Forecast

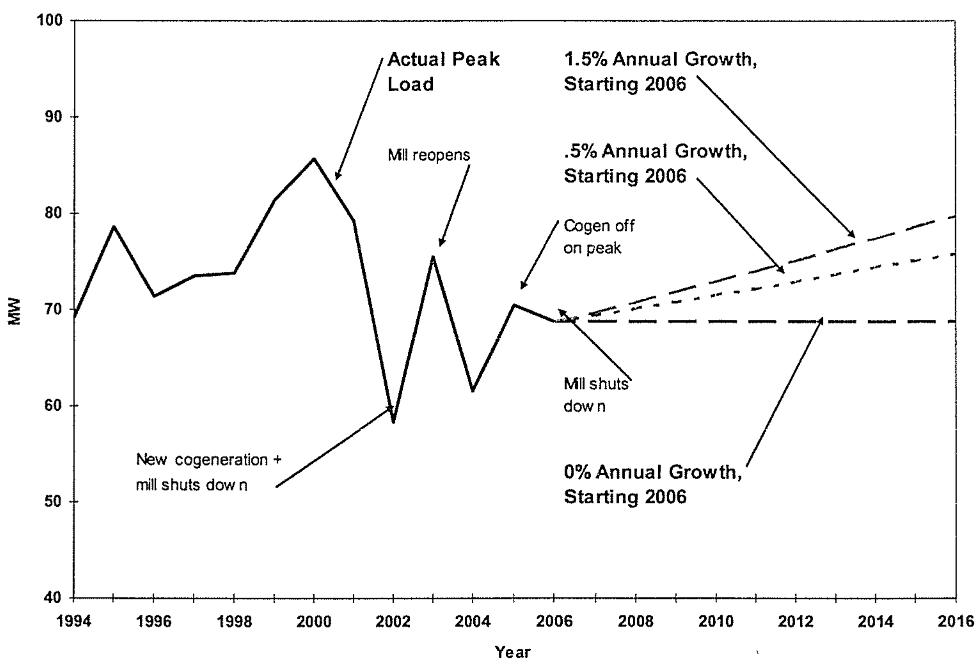


D.4.2. Berlin/Lancaster Area

Exhibit III-19 demonstrates large load fluctuations in the Berlin/Lancaster area caused by changes in demand associated with paper and pulp manufacturing. In 2002, PSNH's electric load in this area dropped by 26 percent from the previous year, primarily due to the closing of a pulp and paper mill in Berlin and the installation and operation of cogeneration by another paper mill in Groveton. In 2003, this load reduction was reversed when the Berlin mill restarted. Additional load was experienced when the Groveton cogeneration facility was off-line during the 2005 peak, transferring plant load to PSNH's system. In 2006, the Berlin pulp and paper mill and the Groveton paper mill shut down operations and can be seen by the drop in peak load in 2006 in Exhibit III-19 below. For this area an EF of 1 percent load growth is forecast assuming a stable economic climate. This has been a summer peaking area the past two years.

The Berlin/Lancaster Area is normally fed by approximately 118 MW of 115-34.5 kV transformer capacity. The 2006 peak demand for this area was 69 MW. No new capacity is required in this area through 2016.

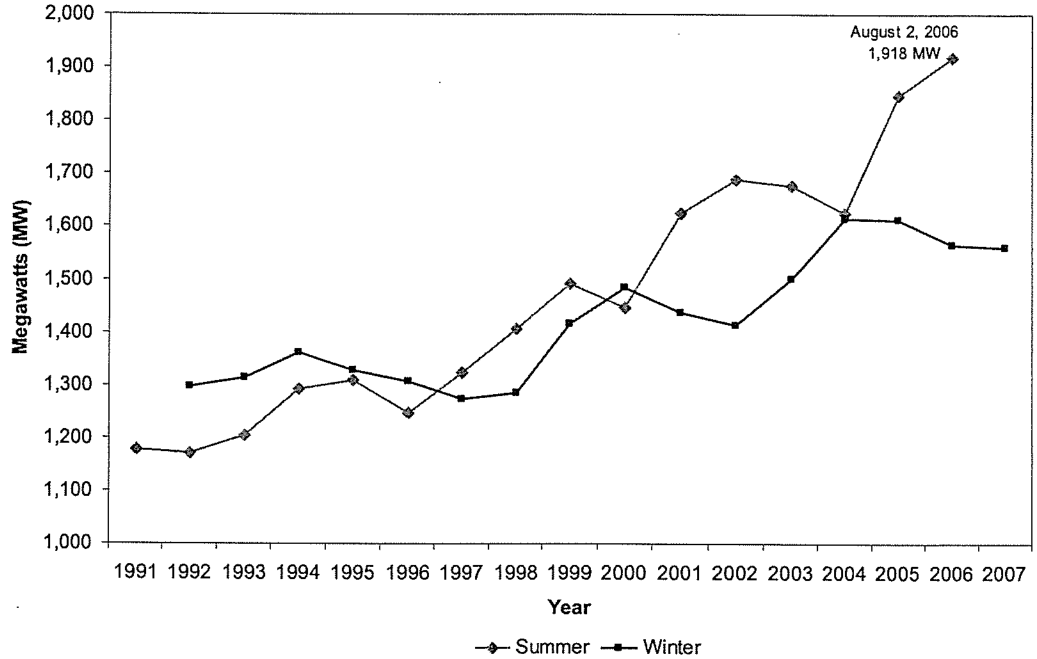
Exhibit III-19: Berlin/Lancaster Area Summer Peak Load Forecast



D.5. PSNH Actual Peak Load Curves

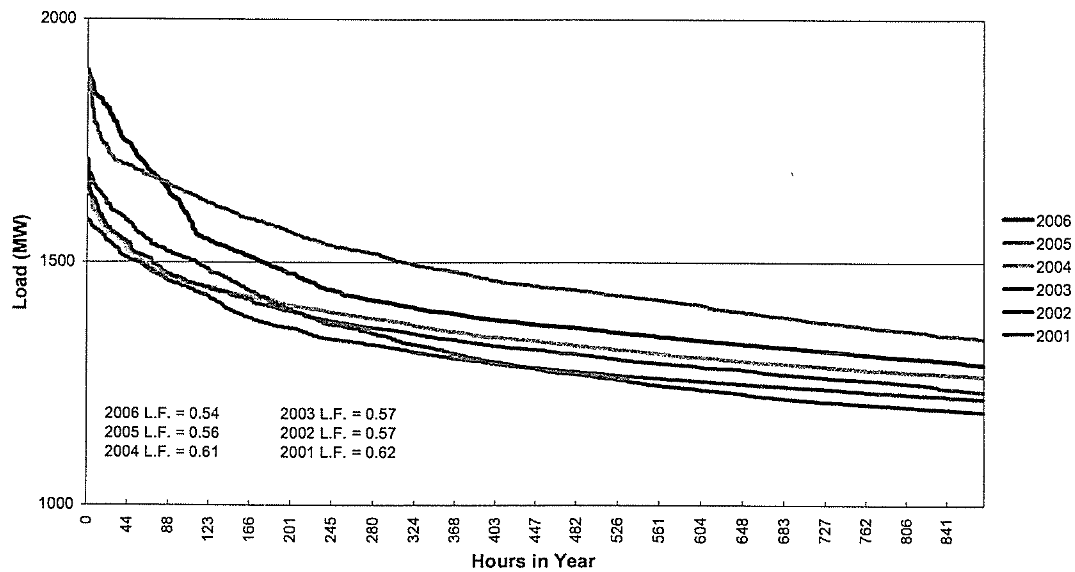
Since 1997, PSNH has been a summer peaking utility as depicted on Exhibit III-20. This is primarily because of the reduction in the use of electric heat and increase in the use of air conditioning by PSNH's customers. An increase in load related to residential air conditioning has been a significant factor during the past several years, partly because residential load is generally more temperature sensitive than industrial load. PSNH's historical compounded summer actual peak demand growth rate is 3.3 percent while the winter growth rate is 1.7 percent.

Exhibit III-20: PSNH Peak Load Curve by Season



The summer peaks indicate a pattern of higher peaks of shorter duration. Exhibit III-21 shows the Annual Duration Curves and subsequent load factors for the highest 10 percent of hourly loads. All of the top 1 percent of hours occurred during the summer with the exception of 2004 which was a mild summer. The use of air conditioning appears to be a driving factor for the summer peaks.

Exhibit III-21: PSNH Load Duration Curves, 2001-2006, Top 10% of Hours



Energy use has increased an average of 2.5 percent per year over the last 5 years. Peak demand has increased an average of 3.6 percent annually over the last 5 years. This pattern likely reflects more homes and apartments utilizing air conditioning units. These are not used weekly or daily but only on the hottest days and often only after multiple 90 degree+ days. They generate a peak growth rate (in kW) higher than the overall load growth rate (in kWh). The end result is a lower Load Factor ("LF").

The LF which was 0.62 or 62 percent in 2001 decreased to 54 percent in 2006. The calculation for this is:

LF = kWh / (kW Peak x 8,670 Hours per Year)

The lower LF requires the installation of additional peak capacity which will be used for fewer hours on an annual basis.

Some peak demand reducing methods such as the Peak Smart program have been in place and used successfully. However, there is a trend toward higher peaks which require capital investment for a short duration of use. C&LM or Distributed Generation may be used effectively to reduce the peak demands and defer some of the peak load driven investments.

IV. Assessment of Demand-Side Energy Management Programs

In Order No. 24,965, the Commission directed PSNH to conduct a "systematic evaluation of reasonably available DSM programs". This section addresses that directive and begins with an assessment of the available demand side potential. This assessment is followed up with an examination of the programs currently offered by PSNH as well as some programs the Company has analyzed as possible future offerings. In addition there is a discussion of the demand-side programs sponsored by ISO-New England and offered to New Hampshire customers by third party providers. Following the discussion of available demand-side resources, there is a review of the Total Resource Cost and Rate Impact Method cost-effectiveness tests and their potential impacts on resource availability.

A. Demand Side Potential

A.1. Analytical Framework

The first step in this evaluation was to develop the analytical framework described below to assess the magnitude of demand side resource potential in terms that are meaningful within the current LCIRP context and realistic from the standpoint of establishing attainable goals. The analytical framework consists of the development of benchmarks that can be employed to assess the resource potential of DSM activities that are not currently being implemented as part of the CORE Energy Efficiency ("EE") Programs. A meaningful benchmark is the quantitative impact of non-CORE program implementation or expansion of CORE program activity on forecasted summer peak demand (MW) and energy sales (MWh) over the planning horizon.

The following benchmarks were identified as points of reference that can be used to bracket the available resource potential:

- **No Load Growth** – A straightforward benchmark is the magnitude of annual savings required to completely offset growth in summer peak demand and sales.

- **Economically Unconstrained Potential** – This was defined in a 2005 study[3] sponsored by Northeast Energy Efficiency Partnerships ("NEEP") of energy efficiency potential in New England as "the potential for maximum market penetration of energy-efficient measures that are cost-effective according to the Total Resource Cost test and that would be adopted through a concerted, sustained campaign involving proven programs and market interventions, and not bound by any budget constraints".

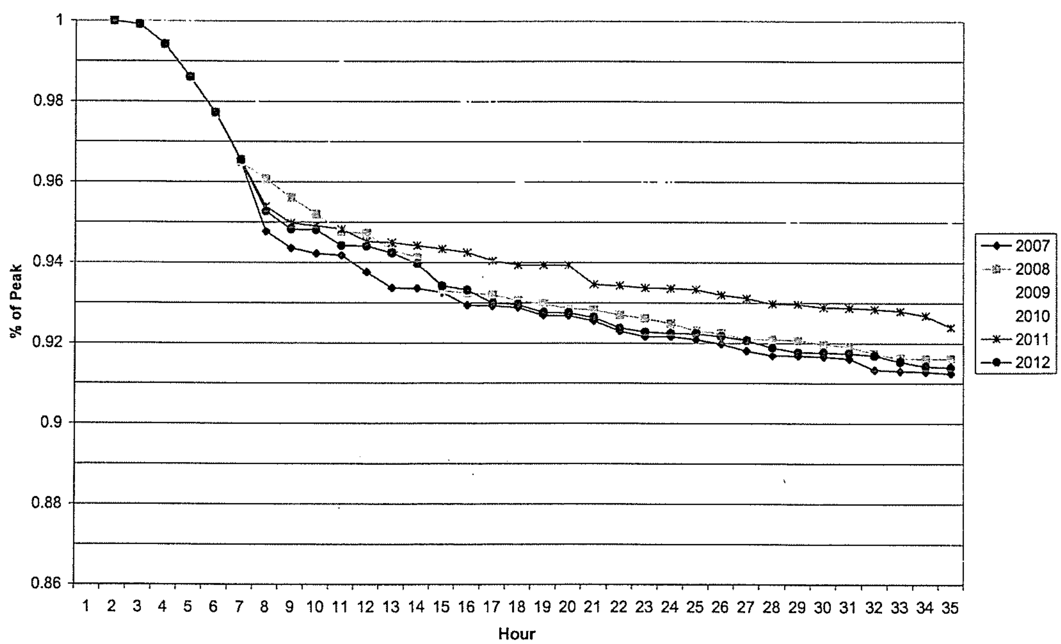
- **Program Potential** - This benchmark is defined as the impact on peak load and sales that can be reasonably achieved as indicated by the historical achievements of programs that have substantial financial and political support for aggressive implementation goals. It incorporates constraints that were not employed in the

[3] *Economically Achievable Energy Efficiency Potential*, p. 4 (May 2005 for Northeast Energy Efficiency Partnerships).

New England study. Most important is the recognition of an implicit budget constraint. This constraint is reflected in the fact that even the most aggressive programs are subject to limitations on program funding. Another constraint is the limitation of the scope of utility program influence. A substantial contribution to the estimated Economically Achievable Potential in the New England Study was realized through changes to state building codes, including stricter enforcement, and the adoption of state product efficiency standards. The achievability of such potential obviously depends on many factors that are beyond the control of an individual utility.

- **Peak Management Potential** – This benchmark is defined as the level of reductions from programs implemented to achieve an annual 5 percent reduction in PSNH summer peak demand. This benchmark was established on the basis of the forecasted annual load duration curve data presented in Exhibit IV-1. The analysis indicates that there is an opportunity to achieve a 5 percent reduction of peak demand by new measures that could be implemented during the 7 to 35 highest annual load hours.

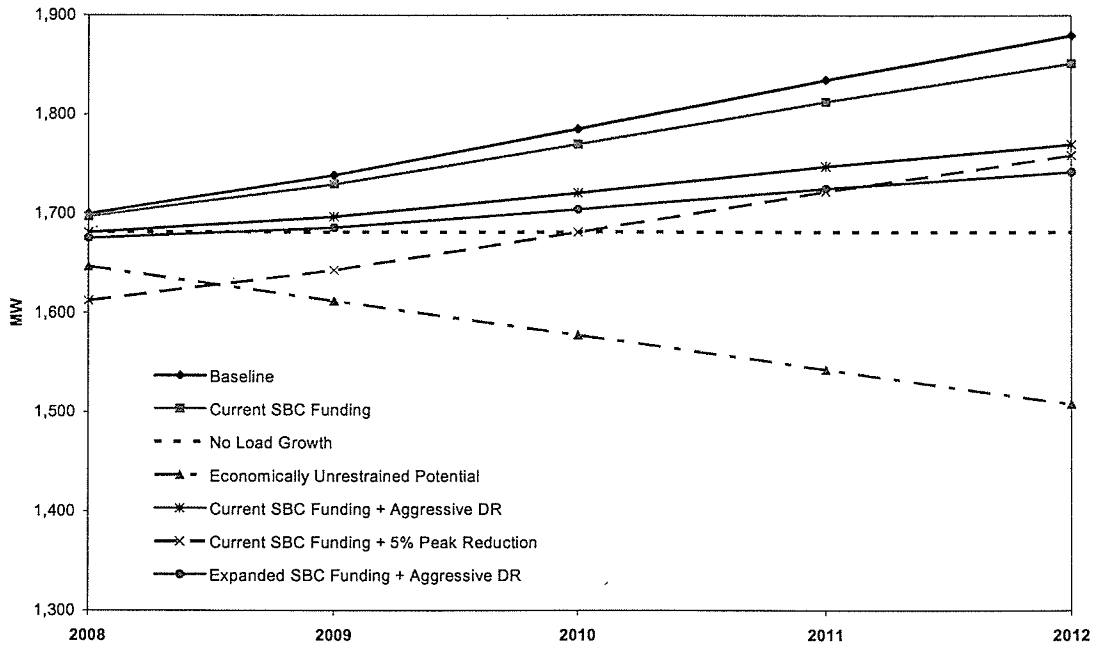
Exhibit IV-1: Forecasted Annual Load Duration Curves, 2007-2012



A.2. Potential Summer Peak Demand (kW) Reductions

The potential to achieve summer peak demand reductions through a combination of Energy Efficiency ("EE") Program measures and Demand Response ("DR") measures is illustrated in Exhibit IV-2.

Exhibit IV-2: Summer Peak Reduction Potential



The following benchmark forecasts are presented and summarized in Exhibit IV-3:

- **Baseline** – The Baseline forecast of summer peak demand represents PSNH's Reference Forecast modified to remove the impact of future energy efficiency program activity. The CAGR for the planning horizon 2007-2012 is 2.3 percent.

- **Current SBC Funding** – The Current SBC Funding benchmark includes the impact of current energy efficiency program funding through the SBC, assuming that current funding will continue through 2012. The CAGR under this scenario is 1.9 percent.

- **Current SBC Funding + Aggressive DR** – The Current EE + Aggressive DR benchmark represents the potential to achieve peak demand reductions through a combination of energy efficiency programs funded at current SBC levels and Demand Response programs that are capable of attaining peak savings commensurate with the levels achieved by Connecticut Light and Power ("CL&P"). CL&P has implemented aggressive DR programs in order to reduce the cost of congestion and to improve the reliability of service. The Connecticut Legislature has authorized funding of customer energy efficiency incentives through its Federally Mandated Congestion Charges ("FMCC") on retail customers' bills in addition to the SBC funding for energy efficiency programs. Additionally, the ISO-New England

Forward Capacity Market provides incentives for measurable demand reduction programs. The projected impact on PSNH's peak demand is proportional to CL&P's current projections of achievable DR, incremental to peak load reduction funded through the Connecticut SBC, based on their accomplishments to date. This benchmark reduces growth to a CAGR of 1.0 percent.

- **Expanded SBC Funding + Aggressive DR** – The Expanded SBC Funding + Aggressive DR benchmark combines the Aggressive DR benchmark described above with an increase in SBC funding to 3 mills/kWh. Use of this benchmark results in a CAGR of 0.7 percent.

- **No Load Growth** – This benchmark represents summer peak demand held constant at the 2007 forecasted level (CAGR=0 percent).

- **Current SBC Funding + 5% Peak Reduction** – This benchmark holds SBC funding constant at 1.8 mills/kWh and assumes additional programs to achieve a 5 percent peak demand reduction in addition to the impact of current energy efficiency program savings. This benchmark produces a CAGR of 0.9 percent.

- **Economically Unrestrained Potential** – This benchmark applies the results of the NEEP study of EE potential in New England to New Hampshire. The study results were employed as follows. The Vermont potential is reported by NEEP as approximately 30 percent achievable in 10 years. The Massachusetts potential is reported by NEEP as 31 percent of residential sales and 21 percent of commercial and industrial sales. When applied to PSNH's sales by sector, the weighted average is 25 percent of sales. Assuming that 50 percent of the Vermont potential (15 percent) is achievable in 5 years, PSNH's potential was estimated as the intermediate value of 20 percent. The 20 percent factor was applied to the 2012 Baseline forecasted summer peak demand.

Exhibit IV-3: Summer Peak Demand (MW) Reduction Potential

	CAGR	2012 MW	2012 MW Chg	2012 % Chg
Baseline	2.3%	1,880	-	0.0%
Current SBC Funding	1.9%	1,851	28	1.5%
Current SBC Funding + Aggressive DR	1.0%	1,770	110	5.9%
Current SBC Funding + 5% Peak Reduction*	0.9%	1,759	121	6.4%
Expanded SBC Funding + Aggressive DR	0.7%	1,742	138	7.3%
No Load Growth	0.0%	1,681	199	10.6%
Economically Unrestrained Potential	(2.1)%	1,508	372	19.8%

Note: The 2007-2012 CAGR for the 5% Peak Reduction projection is based on the 2007 year-end demand at current EE funding.

These benchmarks demonstrate that there is potential for substantial summer peak load reduction via Demand Response programs beyond the projected impact of the current CORE programs funded by the SBC if additional funding were available and effective peak load reduction programs could be designed.

The State of Connecticut has invested significantly in energy efficiency and demand response initiatives and until very recently, Connecticut had the highest SBC in the northeast at 3 mills per kWh. Given this significant investment, the Connecticut model has been chosen as the benchmark for the high end of what is achievable for demand reductions. The Connecticut experience demonstrates there is potential to reduce annual growth in peak demand from approximately 1.9 percent to 1.0 percent through demand response initiatives proportional to those implemented by CL&P. Even with the additional funding and support, the level of demand reduction achieved is still far less than the NEEP benchmark which projects a 2.1 percent drop in demand growth. Further expansion of the funding for the current CORE programs could further reduce the annual peak demand growth to 0.7 percent. It is important to note that these are just benchmarks to use as a comparison for potential demand reduction programs.

According to these projections, a 4.4 percent Peak Management Potential, representing a 0.9 percent decline in annual growth after energy efficiency program impacts, appears achievable, if the Connecticut experience could be replicated in New Hampshire. Actual results will depend on a number of factors including:

- **Funding** – As discussed above, CL&P has relied on supplemental funding authorized by the legislature and Department of Public Utility Control to pursue aggressive demand reduction programs.

- **Environmental Regulations** – The Connecticut Department of Environment Protection has authorized the operation of emergency generators during periods of peak demand. Emergency generators provide a significant contribution to the DR savings in Connecticut.

- **Cost-Effectiveness** – The economic value of DR in New Hampshire may be significantly different than the corresponding value imputed to DR in Connecticut.

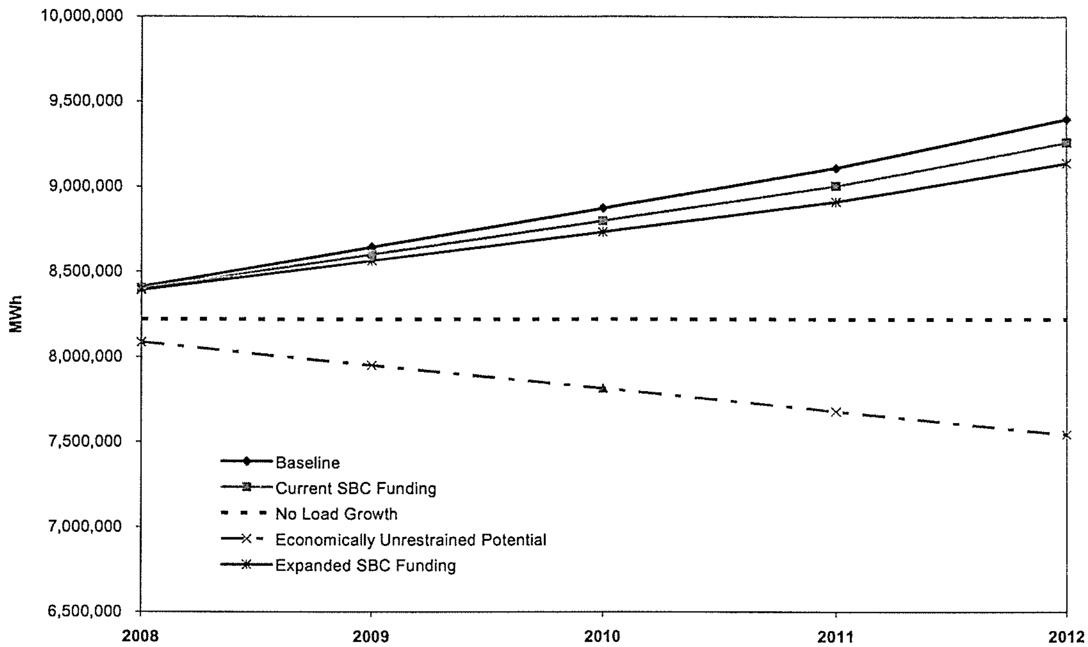
- **Customer Infrastructure** – The magnitude of DR potential depends on the customer base, the availability of emergency generators, the existing EMS and metering infrastructure, and the nature of the facility management resources that can be leveraged to implement such programs.

This assessment is further supported by a 2006 survey conducted by FERC staff which reviewed the DR potential in different regions across the country and reported a potential of 6 percent of peak demand in the Northeast Power Coordinating Council ("NPCC") region. Also, DR professionals have cited 5 percent as a rough target for these types of programs.

A.3. Potential Energy (MWh) Reductions

The potential to achieve energy reductions through the implementation of Energy Efficiency Program measures is illustrated in Exhibit IV-4.

Exhibit IV-4: Energy Reduction Potential



The following benchmark forecasts are presented and summarized in Exhibit IV-5:

- **Baseline** – The Baseline forecast of annual MWh sales represents PSNH's Reference Forecast modified to remove the impact of future energy efficiency program activity. The CAGR for the planning horizon 2007-2012 is 2.7 percent.

- **Current SBC Funding** – The Current SBC Funding benchmark includes the impact of current energy efficiency program funding, assuming that current funding will continue through 2012. The CAGR is 2.4 percent.

- **Expanded SBC Funding** – This benchmark projects a sales reduction impact using energy efficiency programs funded at a level of 3 mills/kWh. Use of this benchmark results in a CAGR of 2.1 percent.

- **No Load Growth** – This benchmark represents annual sales held constant at the 2007 forecasted level (CAGR=0 percent).

- **Economically Unrestrained Potential** – This benchmark applies the results of the NEEP study of potential in New England to New Hampshire. The study results were employed as follows. The Vermont potential is reported by NEEP as approximately 30 percent achievable in 10 years. The Massachusetts potential is reported by NEEP as 31 percent of residential sales and 21 percent of commercial and industrial sales. When applied to PSNH's sales by sector, the weighted average is 25 percent of sales. Assuming that 50 percent of the Vermont potential (15 percent) is achievable in 5 years, PSNH's potential was estimated as the intermediate value of 20 percent. The 20 percent factor was applied to the 2012 Baseline forecasted annual sales.

The benchmarks are summarized in the table in Exhibit IV-5 below.

Exhibit IV-5: PSNH Energy (MWh) Reduction Potential

	CAGR	2012 MW	2012 MWh Chg	2012 % Chg
Baseline	2.7%	9,397,684	-	0.0%
Current SBC Funding	2.4%	9,259,619	138,065	1.5%
Expanded SBC Funding	2.1%	9,138,164	259,520	2.8%
No Load Growth	0.0%	8,221,539	1,176,145	12.5%
Economically Unrestrained Potential	(1.7)%	7,543,843	1,853,841	19.7%

These benchmarks illustrate that there is potential for additional energy reduction beyond the projected impact of the current CORE programs funded by the SBC. If SBC funding was expanded to 3 mills/kWh, there is the potential to reduce growth in annual sales from approximately 2.4 percent to 2.1 percent through expanded participation in the CORE programs.

B. CORE Energy Efficiency Programs

B.1. Background

The CORE Energy Efficiency Programs were born out of the Energy Efficiency Working Group recommendations[4] that were developed between May 1998 and June 1999 and largely approved by the Commission in November 2000[5]. Thereafter, the New Hampshire electric utilities, the Commission Staff, and other interested parties held numerous technical sessions and settlement talks and made many filings before they received final approval from the Commission in May 2002[6] to launch the CORE programs. This represented the first time that a coordinated effort had been made by the electric utilities to offer the same programs statewide.

There are eight CORE programs providing products and services tailored for business, residential and income eligible customers. Each year the New Hampshire electric utilities work together to review the CORE programs, make adjustments and improvements as needed or suggested by customers, interested parties, Staff, and program administrators.

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4 Final Report of the Energy Efficiency Working Group, July 6, 1999, Docket No. DR 96-150.

5 Order No. 23,573, November 1, 2000, Docket No. DR 96-150, Energy Efficiency Programs - Order Establishing Guidelines for Post-Competition Energy Efficiency Programs

6 Order No. 23,982, May 31, 2002, Docket No. DE 01-057, Joint petition for Approval of CORE Energy Efficiency Programs - Order Approving Settlement Agreement and Authorizing Implementation of Programs

PSNH also has five utility-specific programs designed to explore new ideas and practices not addressed by the CORE programs or to test new technologies. Since their introduction the CORE programs have evolved in response to changing technology, market conditions, program evaluations, and new standards as well as input from customers and other interested parties. PSNH is confident that through a combination of prescriptive and custom incentives the CORE programs offered today can accommodate nearly any cost-effective electric energy saving technology of interest to customers.

B.2. Impacts on Energy Consumption

The table in Exhibit IV-6 below summarizes PSNH's actual expenditures, lifetime kilowatt-hour savings, and customer participation for 2006, the most recently completed program year. As a group, the commercial and industrial programs accounted for just over 75 percent of the reductions and the residential programs provided approximately 25 percent. While important for experimentation and innovation, the utility specific programs accounted for only about five percent of PSNH's budget and savings in 2006. While there are some year-to-year variations, these results are typical of those achieved since the launch of the CORE programs.

Exhibit IV-6: 2006 CORE Program Results

	Expenditures		Savings		Customers	
	Dollars	%	$kWh_{lifetime}$	%	Number	%
Residential (nhsaves@home)						
ENERGY STAR Homes	$699,919	12.3%	5,342,894	3.1%	473	1.0%
Home Energy Solutions	$1,432,868	25.3%	36,894,166	21.1%	1,082	2.2%
Home Energy Assistance	$1,727,126	30.4%	21,517,679	12.3%	938	1.9%
ENERGY STAR Lighting	$843,451	14.9%	58,822,127	33.7%	34,907	72.1%
ENERGY STAR Appliances	$679,864	12.0%	33,834,567	19.4%	10,964	22.7%
Residential Utility Specific	$289,770	5.1%	18,351,075	10.5%	36	0.1%
Total Residential	**$5,672,998**	**46.6%**	**174,762,508**	**23.7%**	**48,400**	**97.9%**
Commercial & Industrial (nhsaves@work)						
Small Business Energy Solutions	$1,870,720	28.7%	120,242,582	21.4%	680	66.3%
Large Business Energy Solutions	$2,413,677	37.1%	262,511,386	46.6%	186	18.1%
New Construction	$1,832,118	28.1%	161,463,375	28.7%	154	15.0%
Commercial & Industrial Utility Specific	$395,752	6.1%	18,569,370	3.3%	5	0.5%
Total Commercial & Industrial	**$6,512,267**	**53.4%**	**562,786,713**	**76.3%**	**1,025**	**2.1%**
PSNH Totals	**$12,185,264**		**737,549,221**		**49,425**	

Based on the 2006 results, PSNH saved energy at an average cost of 1.8 cents per lifetime kWh[7] – as compared to the current average retail price of a kWh of 14.2 cents[8]. This overall represents a simple benefit ratio on program investment of more than 7:1. Given that the installed measures have an average life of 14 years, the savings will continue well

[7] The 1.8¢/kWh cited here assumes the final year-end expenditures depicted in Exhibit IV.1 will be 10% higher once the shareholder incentive has been determined.

[8] Another viewpoint is to compare the average cost of saving a kWh with the marginal cost of providing a kWh of energy from the market; which at 10 cents/kWh would produce a simple benefit ratio of about 6:1.

into the future, and as energy costs increase, these comparisons will become even more compelling.

B.3. Impacts on Capacity

In addition to the energy savings discussed above, the CORE programs also provide capacity reductions. On June 16, 2006, the FERC approved a Settlement Agreement that addresses the future capacity needs of New England and laid the groundwork for the Forward Capacity Market. Effective December 1, 2006, under FCM rules, the ISO-New England is obligated to pay for qualified capacity reductions in accordance with the rate schedule shown in Exhibit IV-7.

Exhibit IV-7: Transition Period Capacity Payments

Period	Payment
December 1, 2006 to May 31, 2008	\$3.05 / kW-month
June 1, 2008 to May 31, 2009	\$3.75 / kW-month
June 1, 2009 to May 31, 2010	\$4.10 / kW-month

In order to qualify for payments, capacity reductions must have been installed after June 16, 2006, and the organization seeking payment must certify to ISO-New England's satisfaction that the capacity reductions are operational during hours of peak electrical usage. In the case of state-funded programs like the CORE programs, ISO-New England recognizes state utility commission approval as one form of capacity reduction certification. In addition, prior to payment, ISO-New England also requires monthly reporting of all claimed capacity reductions.

As part of its preparation to participate in the first Forward Capacity Auction scheduled for February 2008, PSNH filed with ISO-New England a Qualification Package on June 14, 2007. The Qualification Package included PSNH's estimate of the so-called "new capacity" reductions that will be installed between May 1, 2007, and May 31, 2010. This estimate was based on an analysis of the capacity reductions resulting from measures installed between June 16, 2006, and April 30, 2007, and coincident with the New England system peak. See Exhibit IV-8 for the results of this analysis.

Exhibit IV-8: CORE Program Capacity Reductions
Based On Measures Installed Between June 16, 2006 and April 30, 2007

	Coincident With ISO-New England Peak	
	Summer kW	**Winter kW**
Residential (nhsaves@home)		
ENERGY STAR Homes	22	50
Home Energy Solutions	165	167
Home Energy Assistance	507	1,907
ENERGY STAR Lighting	125	298
ENERGY STAR Appliances	73	133
Residential Utility Specific	9	190
Total Residential	**901**	**2,745**
Commercial & Industrial (nhsaves@work)		
Small Business Energy Solutions	1,205	887
Large Business Energy Solutions	2,458	1,838
New Construction	1,187	737
C & I Utility Specific	137	113
Total Commercial & Industrial	**4,986**	**3,575**
Grand Total (June 16, 2006 – April 30, 2007)	5,888	6,320
Average kW/Month	535	575
Annualized Coincident Capacity Savings	**6,423**	**6,895**

PSNH has developed the necessary reporting and Measurement and Verification ("M&V") plans needed to evaluate the impact of efficiency measures at the time of system peak and thus the capacity reduction value that qualifies for ISO-New England payments. PSNH has successfully qualified its CORE programs capacity reductions and has been receiving payments on behalf of its customers since the start of the Transition Period in December 2006. Furthermore, PSNH is on track to bid its CORE program capacity reductions into the first Forward Capacity Auction in February 2008 and to have placed in service more than 16 MW by June 1, 2010, the start of the FCM's first "commitment period".

Recognizing that the New England electrical grid peaks in the summer, PSNH's cost of the capacity reductions resulting from the CORE programs are estimated by dividing the annual program costs (including an estimated 10 percent shareholder incentive) by the Annualized Summer kW Coincident Capacity Savings from Exhibit IV-8. This calculation results in PSNH's estimated cost of capacity reductions resulting from the CORE programs at $12.50 / kW-month (assuming a 14 year measure life).

B.4. The CORE Programs as a Demand-Side Resource

In summary, each year the CORE programs implemented by PSNH save approximately 740 million $kWh_{lifetime}$ and reduce the coincident New England peak by 6.4 MW at a cost of $13.5 million. The average measure life is 14 years.

In applying this resource it is important to consider several restrictions imposed by New Hampshire legislation. The first example has to do with targeting the CORE programs to specific customers. For example, examining Exhibit IV-8 it becomes evident that the cost to save a kWh for a business customer is about one-third that needed to save a kWh for a residential customer. Shifting program dollars to the commercial and industrial sector would yield more kWh savings. However, PSNH believes that the enabling legislation[9] for the CORE programs requires that the System Benefits Charge revenues be allocated to customers in proportion to the amount collected from each customer class. Another example of targeting would be to use the CORE programs to alleviate problems on heavily loaded circuits and thereby delay the need for capital additions and provide benefits beyond the energy and capacity savings. The electric industry restructuring legislation prohibits the allocation of System Benefits Charge revenues in this targeted fashion[10].

Reliability is another important consideration when evaluating the CORE programs as a means of meeting the energy and capacity needs of PSNH's customers. In general the key factor in determining their ability to perform when needed is their measure life. Unlike some other demand resources, once installed, CORE program measures do not require periodic renewal of customer participation agreements or ongoing customer incentive payments Furthermore, the claimed capacity reductions are always "on" and do not depend upon PSNH's staff, customer personnel, or communication equipment for activation.

B.5. Economic Analysis of CORE Programs

Economic analyses of the CORE programs are conducted and filed annually with the Commission. Those analyses are based on regional and state-wide average avoided costs and as such are not based on PSNH specific costs. The analyses that follow are based on PSNH's avoided costs.

An economic analysis of two funding scenarios was conducted. The analysis employed two alternative economic criteria to compare the two scenarios, the present value of utility Net Revenue Requirement and the present value of the Total Resource Cost. The results are presented in Exhibits IV-9 through IV-13.

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[9] RSA 374-F:3.VI: BENEFITS FOR ALL CONSUMERS states in part, "Restructuring of the electric utility industry should be implemented in a manner that benefits all consumers equitably and does not benefit one customer class to the detriment of another. Costs should not be shifted unfairly among customers..."

[10] RSA 374-F:4.VIII(e) states, "Targeted conservation and load management programs and incentives that are part of a strategy to minimize distribution costs shall be included in the distribution charge, and not included in a system benefits charge."

The two scenarios represent different levels of System Benefits Charge funding:

- Current SBC Funding (1.8 mills/kWh)
- Expanded SBC Funding, representing a 50 percent increase above the current funding level (2.7 mills/kWh). (This scenario is discussed in Section VIII.D.1.)

The two economic criteria are described as follows:

- The Net Revenue Requirement is the net present value, over the life of the measures, of the incremental utility costs associated with continued SBC funding during the period 2008-2012. The annual incremental revenue requirement consists of the difference between program expenditures (increased revenue requirement) and program savings (decreased revenue requirement). The program savings include avoided energy costs, avoided capacity costs and avoided Transmission and Distribution costs.
- The Total Resource Cost is the net present value, over the life of the measures, of the incremental utility and customer costs associated with continued SBC Funding during the period 2008-2012. The annual incremental TRC consists of the difference between program expenditures plus customer costs (increased TRC) and program savings (decreased TRC). The program savings include avoided energy costs, avoided capacity costs, avoided Transmission and Distribution costs and avoided non-electric resource savings, including the cost of fossil fuel consumption and water consumption. (The TRC criterion is discussed in Section IV.F.2.)
- The avoided costs of energy and capacity are based on the reference market price forecast documented in Appendix G. The avoided energy cost includes an additional component to account for the estimated cost of compliance with regulations of power plant CO_2 emissions. The avoided Transmission and Distribution costs are based on an analysis of the amount of investment in Transmission and Distribution capacity that could be avoided by reduction in annual kW demand.

Exhibit IV-9 summarizes the results of the analysis. The Expanded Funding scenario results in a greater cost savings (negative Net Present Value) than the Current Funding scenario, as indicated by both economic criteria. Exhibits IV-10 through IV-13 present the cumulative Net Present Value Revenue Requirement and TRC results for both scenarios.

Exhibit IV-9: Energy Efficiency Program Net Present Value Analysis

SBC Funding Scenario	NPV EE Program Cost	NPV Avoided Electric Cost	NPV Revenue Requirement	NPV EE TRC Cost	NPV TRC Benefit	Net TRC
Current Funding	$59,447,365	$ (94,998,227)	$(35,550,862)	$ 96,298,190	$(116,659,739)	$(20,361,548)
Expanded Funding	$91,154,318	$(159,999,745)	$(68,845,427)	$147,659,964	$(181,661,256)	$(34,001,292)

Exhibit IV-10: Current SBC Funding Net Present Value Revenue Requirements

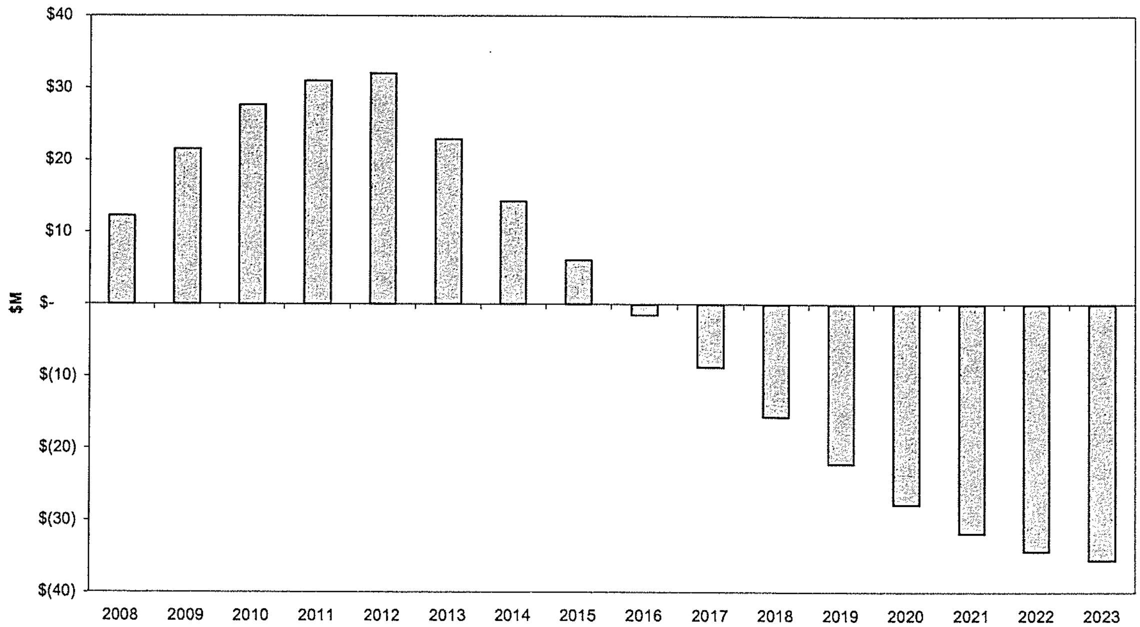


Exhibit IV-11: Current SBC Funding Net Present Value Total Resource Cost

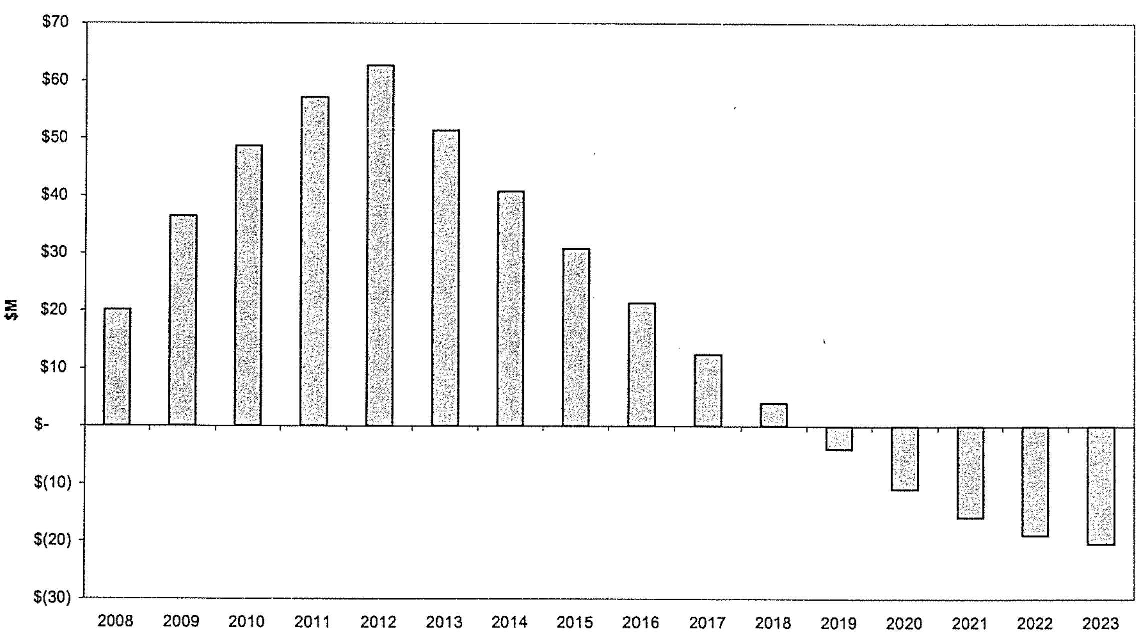


Exhibit IV-12: Expanded SBC Funding Net Present Value Revenue Requirements

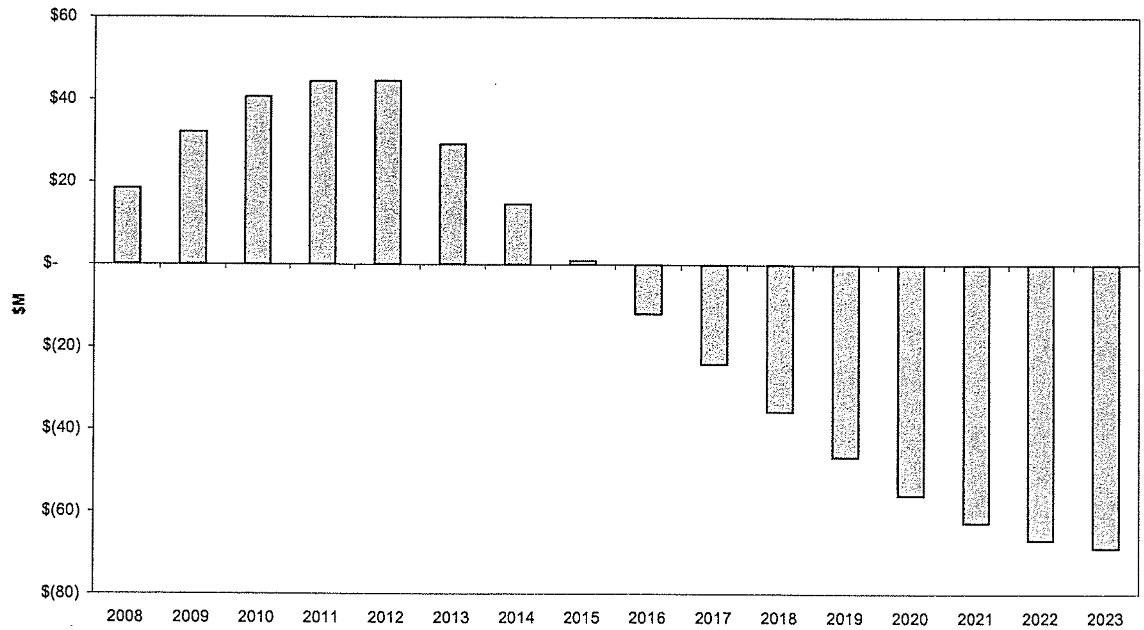
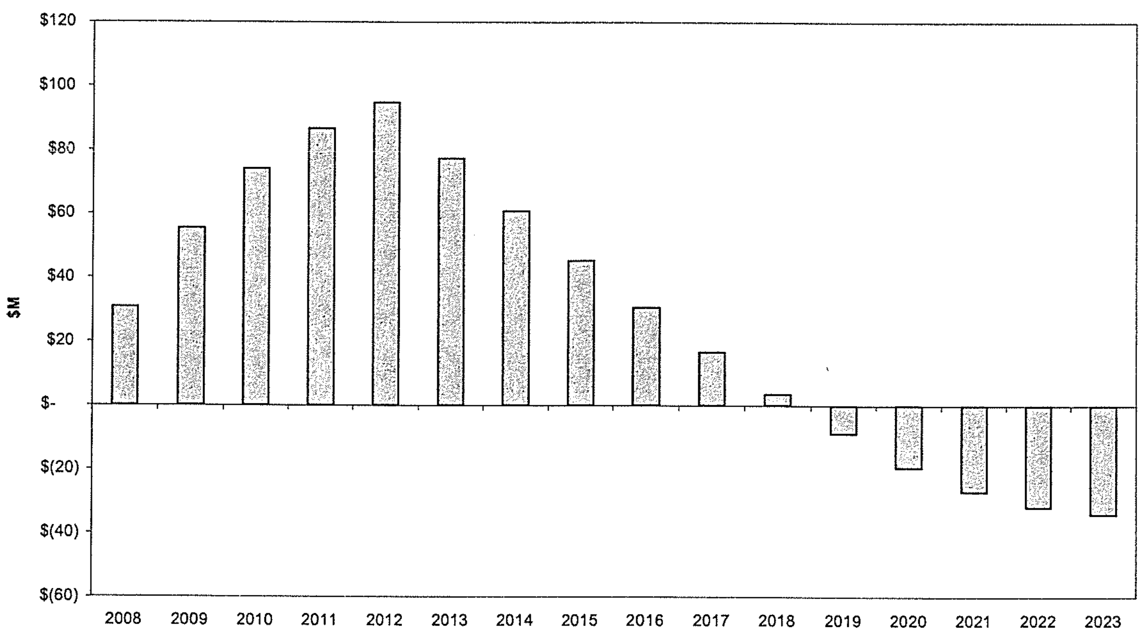


Exhibit IV-13: Expanded SBC Funding Net Present Value Total Resource Cost



C. Demand Response & Load Management Programs

The intent of this section is to review PSNH's current demand response and load management programs and to present an analysis of several new options PSNH has examined for possible expansion of its program offerings. In addition, the ISO-New England administered energy efficiency and demand response programs that are eligible for capacity payments under the pending Forward Capacity Market are reviewed along with energy efficiency programs offered by competitive market providers.

C.1. PSNH's Current Programs

Beyond the CORE Energy Efficiency Programs, PSNH has several demand-side management programs in place that are used to help reduce system demands at periods of high use, high costs, or when there is an energy shortage. The PeakSmart and HEATSMART programs described below operate on a system-wide basis and are not designed to target in a particular geographic area or individual circuit.

C.1.1. PeakSmart (formerly Voluntary Interruption Program)

PSNH's PeakSmart Program (Rate VIP) is operated during the high-load months of June through September each year. The objective of this interruptible load program is to establish a mechanism whereby PSNH can notify large commercial and industrial customers when the regional demand for electricity threatens to reach a peak or during times of high real-time New Hampshire zonal prices as determined by ISO-New England, and request that they curtail load. It is open to larger customers (rates GV and LG) who have hourly metering available to estimate the amount of load curtailment when interruptions occur. This estimate will be based on hourly meter readings adjusted to account for normal load shapes and temperature differences. Participation and interruption is voluntary, with payments based on actual performance. Customers must be willing to interrupt 100 kW or 10 percent of their load, whichever is greater. During the last several years, PSNH has been able to achieve approximately 20 megawatts of voluntary participation among its large customers.

C.1.2. HEATSMART Program

The HEATSMART program offers residential and small commercial customers a discounted delivery rate in exchange for allowing PSNH to curtail their usage using a radio controlled signal sent to equipment installed at the customer's premises. HEATSMART is primarily designed to help control winter peaking demands, and is most often initiated by ISO-New England Operating Procedure No. 4 (Action During a Capacity Deficiency), Action 10, but can also be initiated by the PSNH Dispatcher. This program is available year-round, and the interruptible load is electricity used for space heating (and cooling if using a heat pump) and water heating. These loads are metered and billed separately from other electricity on a non-demand, kilowatt-hour only rate. PSNH has over 3,600 residential customers and 75 commercial customers enrolled in the HEATSMART program. PSNH estimates there are 80 MW of connected HEATSMART load – approximately 8 MW coincident with the New England summer system peak (22 MW winter peak).

In exchange for the lower HEATSMART rate, PSNH can interrupt the HEATSMART load for up to four hours at a time, or up to a total of eight hours in any 24-hour period. An interruption would not affect lighting and other usage. However, no single interruption would exceed four hours in duration and the time between consecutive interruptions would be no less than 2 hours. Interruptions will not occur more than five times in a month and no more than 26 times in a year.

C.2. Potential Program Offerings

PSNH has examined a number of program concepts for possible inclusion in an expanded set of program offerings. The following sections highlight the results of the Company's review.

C.2.1. Interruptible Residential Service

The market for interruptible equipment in the residential sector continues to expand with new products. The equipment is designed to interrupt targeted loads such as air conditioners, water heaters, and pool pumps during periods of peak electrical demand. Similar to PSNH's HEATSMART program, a radio signal is sent to a device at the customer's home that can raise and lower thermostats or cycle equipment on and off.

Newer technologies, such as programmable thermostats, can be controlled by a utility dispatcher to cycle central air conditioning units, raise the temperature one to two degrees per hour for a set number of hours, or lower the temperature of the home in the morning in preparation for an anticipated afternoon interruption. In some cases these devices are web-enabled and the homeowner has the ability to monitor and control thermostats and other equipment remotely from any internet connection.

Two utilities which have recently started utilizing these interruptible technologies for residential customers include Kansas City Power & Light and Florida Power & Light. Both companies are using these interruptible technologies to help reduce energy demand during summer peak periods. The infrastructure supporting these interruptible technologies is emerging rapidly and further evaluation is needed before undertaking a full-scale deployment in New Hampshire. Key unanswered questions include the selection of a particular technology, the magnitude of the peak load reductions attainable for each end-use, customer reaction to the technology and service interruptions, and an assessment of the net benefits and costs.

C.2.2. Cool Storage

PSNH analyzed the use of off-peak cooling ("OPC") systems that use thermal energy storage to provide air conditioning to buildings during peak times. Typically, ice is made at night and is melted during the day to provide cooling. Ice storage tanks, similar to hot water tanks, make and store ice at night during periods of low electrical system demand. The ice is then used to cool air during the day when demand for electric energy is high. Leading suppliers of cooling technology are Ice Energy and Calmac. Currently, both companies have industrial applications on the market and are working towards meeting residential needs. In order to be cost-effective, systems in use today are typically 150 tons or larger (enough to cool 50,000 square feet of office space).

Benefits often cited with this technology include:

- Reduced capacity (kW) requirements during periods of peak electrical demand
- Reduced power plant emissions
- May result in lower cooling costs when service is provided under rate structures with significant price differentiation between on- and off-peak periods

Potential disadvantages include:

- System designs typically combine standard HVAC with a thermal storage system added on, and as a result, they tend to be more complicated and require more real estate resulting in higher initial costs and higher maintenance costs
- While on-peak energy requirements are lower, overall energy use is higher
- Insufficient storage can lead to an inability to provide adequate cooling or a lack of savings on hot days

Cool storage technology has met success in parts of the country where cooling is required most of the year and where a substantial variance exists between on-peak and off-peak energy and demand charges. In New Hampshire there are a relatively small number of hours during the year when the demand for air conditioning is high; furthermore, there is little price differentiation between on-peak and off-peak periods on average. As a result PSNH's conclusion is that this technology is not cost effective in New Hampshire at this time.

C.2.3. Connecticut Light & Power Demand Response Program

In preparation for this filing, PSNH held numerous discussions with its Connecticut affiliate, CL&P. Because of congestion problems, particularly in southwestern Connecticut, CL&P has had to undertake some very aggressive measures in order to avert a power supply crisis. In 2006, CL&P initiated a demand response program in response to directives by the Connecticut Department of Public Utility Control ("DPUC") to fulfill requirements established by the Connecticut General Assembly in Public Act 05-1 ("An Act Concerning Energy Independence") to implement measures to reduce Federally Mandated Congestion Costs.

CL&P has pursued aggressive peak load reduction goals by leveraging the Connecticut Energy Efficiency Fund, demand resource incentives offered through ISO-New England, and other funding sources authorized by the Connecticut DPUC. During 2006, approximately 100 MW of demand response resources were enrolled in an ISO-New England Load Response program. Through the first two quarters of 2007, CL&P has enrolled a total of 143 MW in the program.

The demand response resources are enrolled in the ISO-New England Real-Time Demand Response ("RTDR") program described below in Section C.4. Participating customers are able to reduce their power requirements, upon ISO-New England notification, either through direct load curtailment or operation of on-site emergency generation. CL&P

provides the program participants with technical and financial assistance to enable enrollment in the RTDR program.

The success of the program can be attributed to the availability of funds to pay financial incentives to program participants and effective utilization of established customer service relationships by CL&P staff to promote participation. Large customers that have dedicated facility staff and ongoing relationships with CL&P account executives are good candidates for enrollment. In addition, CL&P employs an Internet Based Communications System ("IBCS") contractor to provide technical services to support the installation of metering and communications infrastructure at the customer's facility and the collection of the data required by ISO-New England to determine the Demand Reduction Value during performance hours.

The Connecticut Department of Environmental Protection provides less restrictive air quality permits that allow for the operation of emergency generators participating in the ISO-New England Load Response program.

Applicability to PSNH

The CL&P experience suggests that there may be an opportunity to implement a similar demand response program in New Hampshire. A threshold condition for System Benefits Charge funding is program cost-effectiveness. A Benefit Cost Analysis was performed to determine if the estimated program benefits exceed the costs.

The program costs include the metering and communications infrastructure, IBCS contractor fees, incentive payments to participating customers, and administrative costs. The primary program benefits are capacity savings associated with demand reduction capability and a secondary benefit is energy savings during actual load interruptions activated by ISO-New England. Two scenarios were analyzed: 1) $80/kW-year customer incentive payment, and 2) $40/kW-year customer incentive payment. The results are presented in Exhibits IV-14 and IV-15.

Exhibit IV-14: Demand Response Benefit Cost Analysis, Incentive = $80/kW-Yr

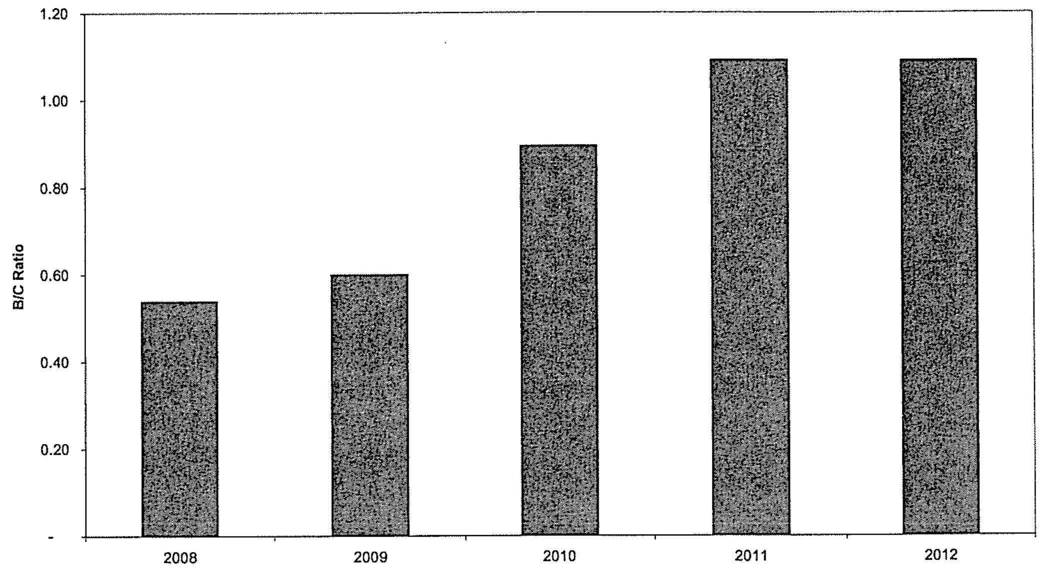
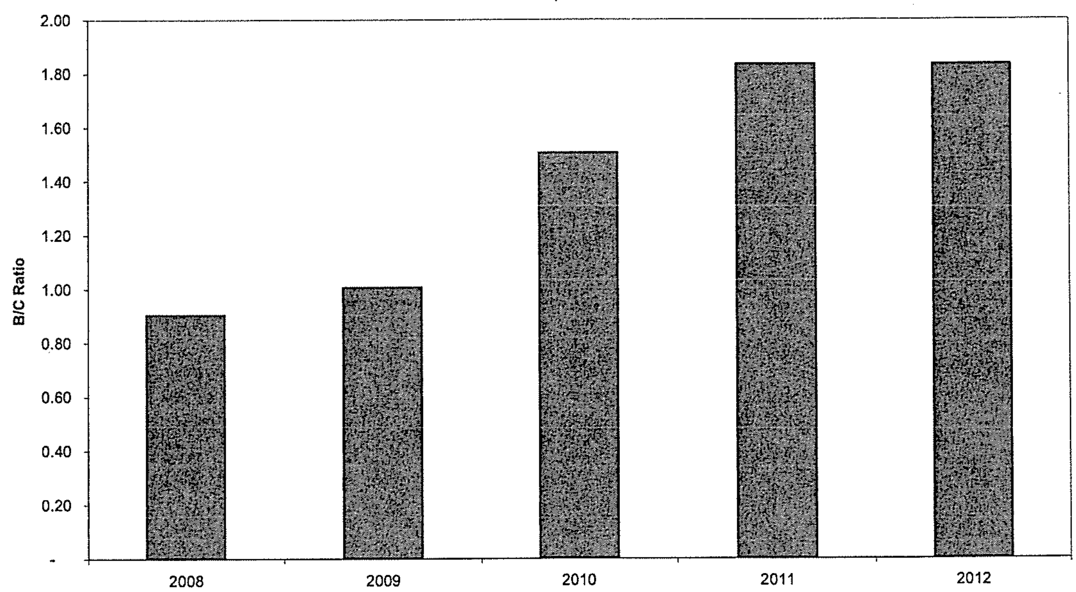


Exhibit IV-15: Demand Response Benefit Cost Analysis, Incentive = $40/kW-Yr



CL&P offers an incentive payment of $80/kW-year to its customers to participate in the demand response program. The second scenario assumes that an incentive approximately equal to the current ISO-New England FCM Transition Payments would be sufficient to induce customers to participate. The cost-effectiveness of the program is very sensitive to the level of the incentive payment. If a payment of $80/kW-year is required, then the program is not projected to be cost-effective (B/C ratio>1.0) until 2011, when the full value of new capacity is projected to be recognized in the ISO-New England Forward Capacity Market. And even then, the program is just barely cost-effective with a B/C ratio equal to

1.09. If the lower $40/kW-year payment is sufficient, then the program is projected to be marginally cost-effective in 2009 and to attain a B/C ratio of 1.84 in 2011. It is important to note that avoided capacity costs in southwestern Connecticut, and therefore the program savings and cost-effectiveness, can vary significantly from PSNH's avoided costs used in this analysis.

Another consideration is the opportunity cost of load interruptions which can vary considerably among customers, depending on the nature of the business, facility management resources, existing infrastructure (e.g., energy management systems, emergency generators) and other factors that are difficult to assess. While CL&P has found that the $80/kW-year payment has been an effective incentive to participate, it is possible that a lower incentive may be sufficient. Besides increasing the cost-effectiveness of DR, a lower incentive would mean that a larger portion of cost could potentially be funded by FCM revenue.

Applicability to New Hampshire

In summary, the Connecticut experience indicates that demand response has significant resource potential, but whether this potential can be cost-effectively realized in New Hampshire is uncertain. Because demand response under the optimistic scenario presented in Exhibit IV-15 is not projected to produce a significant net benefit before 2010, PSNH will review the economics of demand response implementation prior to its next biennial LCIRP filing.

C.3. Dynamic Retail Pricing

Dynamic retail pricing is addressed in DE 06-061, Energy Policy Act of 2005. PSNH has filed testimony explaining its position with regard to dynamic retail pricing in that docket. There are no changes or updates to PSNH's earlier filed testimony on this issue.

C.4. ISO-New England Programs

At the present time, ISO-New England operates three targeted reliability-based demand-response programs and two price-activated energy reduction programs. ISO-New England's demand-response programs include the following:

- **Real-Time 30-Minute Demand-Response Program**—requires demand resources to respond within 30 minutes of ISO-New England's instructions to interrupt.

- **Real-Time 2-Hour Demand-Response Program**—requires demand resources to respond within two hours of ISO-New England's instructions to interrupt.

- **Real-Time Profiled-Response Program**—designed for participants with loads under their direct control that are capable of being interrupted within two hours of ISO-New England's notification to interrupt. Individual customers participating in this program are not required to have an interval meter but are required to develop and submit a monitoring and verification plan for each of their accounts.

ISO-New England's demand response programs are available to individual customers or aggregated groups of customers including commercial and industrial customers capable of reducing their load upon notification by at least 100 kW. Participating customers generally have a monthly peak demand of at least 350 kW during those months when system peaks are likely to occur. Customers enrolled in the ISO-New England program are notified via the IBCS which is the primary path for communication of curtailment event data between ISO-New England, the IBCS (third-party) providers and the individual customers. Upon notification of a demand response event by ISO-New England, each participating customer is responsible for compliance and demand reduction within the time-frame allowed under their respective agreement.

In addition to the demand response programs, ISO-New England administers two price-based programs:

- **Real-Time Price-Response Program**—involves voluntary load reductions by program participants that are eligible for payment when the forecast hourly real-time LMP is greater than or equal to $100/MWh and ISO-New England has transmitted instructions that the eligibility period is open.

- **Day-Ahead Load-Response Program ("DALRP")**—an optional program that allows a participant in any of the real-time programs to offer interruptions concurrent with the Day-Ahead Energy Market. The participant is paid the day-ahead marginal price for interruptions. Any price deviations between the day-ahead market and the real-time market are reconciled.

The ISO-New England Demand-Response programs are activated during zonal or system wide capacity deficiencies in order to maintain or support system stability and reliability. ISO-New England has determined that the Demand-Response programs are classified as "Reliability Program" resources and this classification determines when the participating customers are notified under ISO-New England's Operating Procedure Number 4 ("OP-4"). OP-4 establishes criteria and guidelines for ISO-New England actions during capacity deficiencies and contains 16 action steps that can be implemented individually or in groups depending on the severity of the situation. The Real-Time Two-Hour Demand-Response and Real-Time Profiled-Response programs are activated at OP 4 Action 3 and the Real-Time 30-Minute Demand-Response program is activated at Actions 9 and 12. The resources activated at Action 12 (typically customer-owned emergency generators) may have environmental permit restrictions that require the system operator to implement voltage reductions before calling on these resources to take action under their agreements.

According to ISO-New England, overall enrollment in ISO-New England programs has been increasing steadily during 2006 and 2007. Data for 2006 indicates that participant enrollment in the programs rose approximately 50 percent, from an annual monthly average of 430 MW in 2005 to 646 MW in 2006. ISO-New England published data for 2006 indicates that the Real-Time Price-Response program experienced the most activity during that year with 162 days with interruptions. Of the 162 days, 151 days were the result of the hourly price being at or above the threshold level of $100 per megawatt-hour. The remaining 11 days were the result of the Day-Ahead Demand-Response program. The 30-Minute and Two-Hour Real-Time Demand-Response programs were activated on six days in 2006. Three of the activations took place during the summer months when OP-4 actions were declared. Exhibit IV-16 shows the ISO-New England demand response program enrollment data as of August 31, 2007 for each major demand or price-response program.

Exhibit IV-16: ISO-New England Demand Response Program Enrollment[11]

	Ready to Respond*:					Approved**:				
	2,158 Assets 1,222.9 MW					80 Assets 30.0 MW				
Zone	Assets	RT Price	RT 30-Min	RT 2-Hour	Profiled	Assets	RT Price	RT 30-Min	RT 2-Hour	Profiled
CT	1,160	7.5	623.6	0.8	0.0	65	0.0	20.1	0.0	0.0
SW CT***	597	0.8	329.4	0.8	0.0	30	0.0	9.5	0.0	0.0
ME	36	0.0	160.9	37.1	11.0	0	0.0	0.0	0.0	0.0
NEMA	247	29.0	91.5	0.0	0.0	0	0.0	0.0	0.0	0.0
NH	37	4.5	19.1	1.3	0.0	2	0.0	0.4	0.5	0.0
RI	186	16.7	47.6	3.9	0.0	2	0.0	1.0	1.1	0.0
SEMA	203	10.5	34.0	1.5	0.0	6	0.1	0.0	5.0	0.0
VT	40	6.7	16.8	0.3	5.9	1	0.0	0.2	0.0	0.0
WCMA	249	21.0	53.6	18.2	0.0	4	0.0	0.9	1.0	0.0
Total	2,158	95.8	1,047.1	63.0	16.9	80	0.1	22.5	7.4	0.0

Notes:
*Ready to Respond means the registration process is complete and the resource is eligible to participate in an Event
**Approved means the application for registration has been approved by ISO-New England
***SWCT assets are included in CT values and are not included in Total

The load control impact that the ISO-New England programs have thus far had on New Hampshire retail customers is minimal when compared with the amount subscribed in critical-need areas such as Connecticut – especially Southwest Connecticut. The critical need for such programs in southern areas of New England has been substantial in order to mitigate the impact that peak load growth has had on areas lacking sufficient load transfer capability. It is important to note that the demand- and price-response programs play an important role in managing system reliability on the record peak-demand day. Absent such load interruptions, the peak demand in 2006 would have been hundreds of megawatts higher. PSNH anticipates that as customer awareness increases and third party demand response providers contact more customers, the amount of load under agreement will continually increase in 2007 and beyond.

C.5. Competitive Market Provider Programs

As described above, customers now have a variety of programs made available by ISO-New England to reduce load and/or reduce energy costs during times of high load or high energy costs. Under the programs, a third party or individual can arrange with ISO-New England to become an "Enrolling Participant" and will then be eligible to work with qualifying customers and enroll them in one of ISO-New England's demand response programs. It is important to note that a third party Enrolling Participant can enroll customers within PSNH's franchise area without PSNH's knowledge or involvement. Any customer who can make a commitment to reduce their power consumption by a minimum of 100 kW within 30 minutes or 2 hours of ISO-New England's request to curtail load can participate. Additionally, the local distribution utility that serves participating customers will register a load reduction on its delivery system.

[11] ISO-New England website, "Load Response Statistics as of 08-31-2007", http://www.iso-ne.com/genrtion_resrcs/dr/stats/enroll_sum/index.html

D. Distributed Generation Options

Distributed Generation ("DG") is generation located on the distribution system, under 25 MW, and interconnected to PSNH's system at 46 kV or below. This includes customer owned facilities, independent power producers, and PSNH hydro and combustion turbine facilities. DG facilities are operated interconnected to the power grid and customer owned facilities may be interconnected to supply the customer's load on their side of the meter.

Large power plants have excellent economies of scale, but require an electric transmission grid to transmit power to customers. DG can be located in close proximity to load thereby eliminating the need to transmit the power through the transmission system. Locating DG at the distribution system level reduces system losses if located at or near the load and provides the potential to reduce the peak demand on equipment throughout the grid. Reducing local peak demand can delay upgrades to the infrastructure required to prevent overloads during peak load conditions. The reduction of losses and peak demand also results in avoided Installed Capacity ("ICAP") payments. PSNH has been able to utilize its hydro and CT units effectively to benefit the PSNH distribution system. These distributed generation units are capable of supporting the system for various operating scenarios which offset capital investments.

Certain DGs produce waste heat that can be used for space, water heating or other combined heat and power ("CHP") uses. It is this use of DG that is the most efficient, utilizing the electricity in addition to the heat by-products produced. Some of PSNH's customers utilize this technology today. The enactment of the New Hampshire Renewable Portfolio Standard and the ISO-New England Forward Capacity Market may increase the use of DG on PSNH's system over the next few years. RPS subsidies may encourage PSNH's customers to consider utilizing green technologies when installing DG to meet their energy needs. Customers participating with renewable generation may help PSNH to meet New Hampshire RPS requirements. Additionally, the ISO-New England Forward Capacity Market provides potential capacity subsidies to DG facilities.

The location of new customer-owned or merchant-owned DG on PSNH's system is not known. There is an opportunity for the siting of facilities to be integrated into PSNH's planning process to optimize the impact on PSNH's distribution facilities. Based on cost per kilowatt (kW) of capacity, DG may be a cost effective method to address system-wide load growth and/or peak load requirements. If DG is sited in an area where it offsets load there is an additional overall distribution system benefit.

Renewable energy and distributed generation technologies are critical to the future energy portfolio of New Hampshire. Energy access, energy security, and environmental considerations, combined with increasing fossil fuel prices, are key drivers for accelerating the adoption of affordable distributed generation. Working within this framework, PSNH could develop a DG model that would provide distribution system benefit through both traditional and new generation technology.

E. Other Influences

E.1. Legislature

As of the date of filing of this plan, there was no pending legislation likely to impact energy efficiency or demand response. However, over the past five years the legislature has considered numerous bills that would modify the CORE programs and/or the available funding. Senate Bill 228 passed in November 2005 reduced the available energy efficiency funds by $2.8 million. It is not the intent here to speculate regarding future legislative actions, but merely to point out that the plans presented here are subject to review upon legislative action.

E.2. Codes and Standards

Updating and enforcing building energy codes and minimum efficiency standards for appliances have the potential for significant energy and capacity savings. However, they are beyond the direct influence or control of PSNH and their impacts have not been included in the development of this plan.

E.3. Forward Capacity Market

The establishment of the Forward Capacity Market and the obligation for ISO-New England to pay for demonstrable demand-side capacity reductions may result in unforeseen market forces and consequences. For example, several of PSNH's large customers have indicated their reluctance to sign an agreement to participate in the CORE programs because in doing so they must forego any rights to capacity payments from ISO-New England[12]. The intent of this provision was to prevent "double dipping" whereby a CORE program participant would receive both a CORE program incentive and an ISO-New England payment for installing the same energy efficiency measure. Customers who sign the participation agreement allow PSNH to receive any ISO-New England capacity payments on behalf of all customers and the monies are then used to fund additional efficiency measures. However, an unintended consequence of this provision would be that a significant number of customers decide not to participate in the CORE programs. While PSNH does not feel this is a significant concern at this time, the situation needs to be watched closely, and its impacts on the CORE programs evaluated.

F. Demand Side Cost-Effectiveness

In Order No. 24,695, the Commission directed PSNH to "undertake a study to determine the effects of using the Rate Impact Method test on demand side management ("DSM") resource availability". In this Section PSNH will provide background information on both the Total Resource Cost ("TRC") test currently used to evaluate the Company's energy efficiency programs and the Rate Impact Method ("RIM") test which the Commission has directed the Company to study. PSNH will then present the results of its analysis of the effects of adopting the RIM test on DSM resource availability.

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[12] This provision was approved by the Commission as part of the 2007 CORE programs (reference *2007 CORE NH Energy Efficiency Programs*, DE 06-135, September 29, 2006, page 4).

F.1. Background

Most states, including New Hampshire, have adopted the TRC test to evaluate the cost effectiveness of DSM programs. The TRC test is designed to promote the efficient allocation of resources through a comparison of the total cost of energy services associated with alternative investment strategies. Thus, given a baseline condition (e.g., "do nothing"), the TRC test provides a measure of the impact of an incremental investment on the total cost of energy services. If the investment produces a net reduction in the total cost of energy service, including the incremental cost of the investment, then the investment is determined to be cost-effective. The TRC accordingly provides an economic framework within which the efficiency of different DSM programs or measures, as well as different energy supply options can be directly compared. However, it's also important to note that the TRC test does not measure the financial impact of energy efficiency expenditures on the utility's investors.

The RIM test is sometimes employed to determine whether a utility investment will reduce the average cost of service per billing unit (i.e., kWh or kW), and therefore, under traditional cost of service ratemaking, lower rates to all customers. The RIM test is motivated by the desire to avoid utility investments that would raise energy costs for any customer, even if the total cost of service were reduced.

The TRC and RIM tests are designed to serve fundamentally different objectives. The TRC test is an economic evaluation of an investment which accounts for all program costs and benefits, regardless of the distribution of costs and benefits to program participants, non-participants or the utility. The RIM test only accounts for program costs and benefits that are distributed via retail electric rates in order to measure the program impact on the retail price of electricity.

F.2. Total Resource Cost Test

Energy efficiency programs can provide the consumer with information, assistance, and incentives to exploit opportunities to reduce the cost of energy services through investment in more efficient equipment. The TRC test compares the magnitude of all cost increases, including the incremental investment and the expenses associated the energy efficiency program, with the magnitude of all benefits (cost reductions), including the reduced (avoided) costs of energy supply and delivery. Exhibit IV-17 depicts the key parameters considered in the TRC test used by PSNH to evaluate the CORE programs.

Exhibit IV-17: TRC Benefits and Costs Symbols and Descriptions

Benefits		Costs	
Symbol	**Description**	**Symbol**	**Description**
AC	Avoided Costs of energy supply, transmission, and distribution	**PC**	Program Costs (e.g., customer incentives, administration, monitoring, evaluation)
CB	Customer Benefits (including O&M)	**CC**	Customer costs (including O&M)
QRS	Quantifiable resource savings (e.g., water, natural gas, etc)	**QRC**	Additional Quantifiable Resource Costs (e.g., water, natural gas, etc)
EB	15% "adder" for non-quantified benefits (e.g., environmental and other benefits)	**SI**	Utility Shareholder Incentive

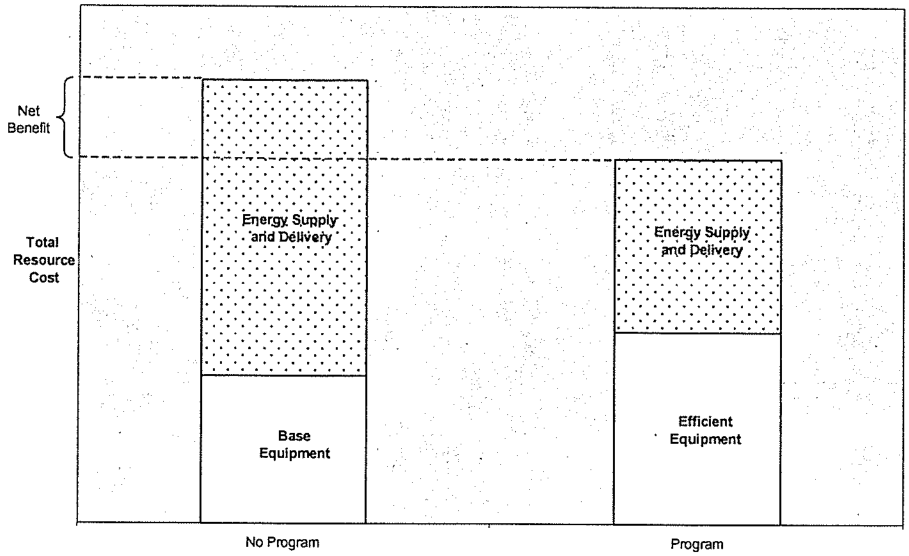
Using the algebraic symbols from the table above, the basic equation used to apply the TRC cost effectiveness test is:

$$\textbf{TRC Net Benefit} = (AC + CB + QRS + EB) - (PC + CC + QRC + SI)$$

This basic equation is useful when all of the costs and benefits are captured over a relatively short period of time (e.g., one year). However, in most practical cases, the costs and benefits accrue over efficiency measure lives that average 14 years. To properly analyze costs and benefits that accrue over multiple years, the basic formula is applied in each year and the project is then evaluated based on the Net Present Value of the TRC Net Benefit.

Exhibit IV-18 illustrates the TRC graphically. The bar on the left depicts equipment and energy supply costs in the absence of any energy efficiency program. The bar on the right depicts the same situation after having taken advantage of a cost-effective efficiency program. While the cost of energy efficient equipment is higher, energy supply costs are lower resulting in an overall net benefit

Exhibit IV-18: Total Resource Cost (TRC) Test



F.3. Rate Impact Method Test

The RIM test is based on the premise that the utility should not make expenditures that will raise rates because some customers' bills will increase, making them worse off than before. While the TRC Test compares the increase in energy service costs (including end-user costs) to all cost reductions (including non-electric resource costs), the RIM test compares the net reduction in utility costs (revenue requirements) to the reduction in utility revenue, sometimes referred to as "Lost Revenue"[13]. If an investment in efficiency reduces utility revenue more than revenue requirements, then rates would have to be increased in order to recover all utility costs. Conversely, if an investment reduces cost more than revenue, revenue requirements can be recovered at lower rates. Exhibit IV-19 depicts the key parameters considered in the RIM test analyses used by PSNH.

Exhibit IV-19: RIM Test Parameters

Net Utility Cost Reductions		Change In Utility Revenues	
Symbol	**Description**	**Symbol**	**Description**
AC	Avoided Costs of energy supply, transmission, and distribution. This is a savings to the utility and thus a positive cost reduction.	**LR**	Lost Revenue (i.e., the reduction in distribution system revenues resulting from the installation of energy saving measures)
PC	Program Costs (e.g., incentives, administration, monitoring, evaluation). This is a cost to the utility, and thus a negative cost reduction.		

[13] "Lost Revenue" is a misnomer because the RIM test is based on the assumption that rates will be ultimately be adjusted to recover all revenue requirements, albeit at a potential loss to utility investors if there is a delay to the rate adjustment.

Using the algebraic symbols from the table above, the basic equation used to apply the RIM cost-effectiveness test is:

RIM Net Benefit = (AC – PC) – LR

As discussed above in the description of the TRC test, this basic equation is useful only when all of the costs and benefits are captured over a relatively short period of time. To properly analyze a project with effects that span multiple years, the basic formula is applied in each year and the project is then evaluated based on the Net Present Value of the RIM Net Benefit.

Examining the basic RIM equation, one can see that any efficiency improvement, regardless of its cost-effectiveness and including measures that can be implemented at no cost, will fail the RIM test if the lost revenue is greater than the avoided cost. Conversely, if the utility's net cost reductions from a project (i.e., the savings), exceed the lost revenues, then any program which costs the utility less than the difference between the savings and lost revenues will pass the RIM test. Considering these two observations together, it becomes clear that reliance on the RIM test can disqualify measures that are cost-effective for customers but at a potential short-term loss to investors, and it can qualify other measures which are not cost-effective for customers.

F.4. Effect of Using the RIM Test on DSM Resource Availability

In order to determine the impact of adopting the RIM test on the availability of demand side resources, PSNH analyzed three of the top performing CORE programs: ENERGY STAR Lighting, Small Business Retrofit, and Large C&I Retrofit. Based on the most recent analyses presented in the 2007 CORE New Hampshire Energy Efficiency Programs filing, these programs provided the most energy savings – more than 65 percent of the total, had the highest level of net benefits, and had some of the best benefit-to-cost ratios as determined by the TRC test. As a group, both from a kWh savings and a cost-effectiveness perspective, these are the three best performing programs offered by PSNH.

The results of our RIM test analyses are presented below in Exhibits IV-20, IV-21, and IV-22. None of the programs pass the RIM test. In each case the Lost Revenues when combined with the energy efficiency Program Costs exceed the Avoided Cost savings thus resulting in a higher average price to customers, but not a higher overall cost of service.

Exhibit IV-20: RIM Test – Residential Lighting

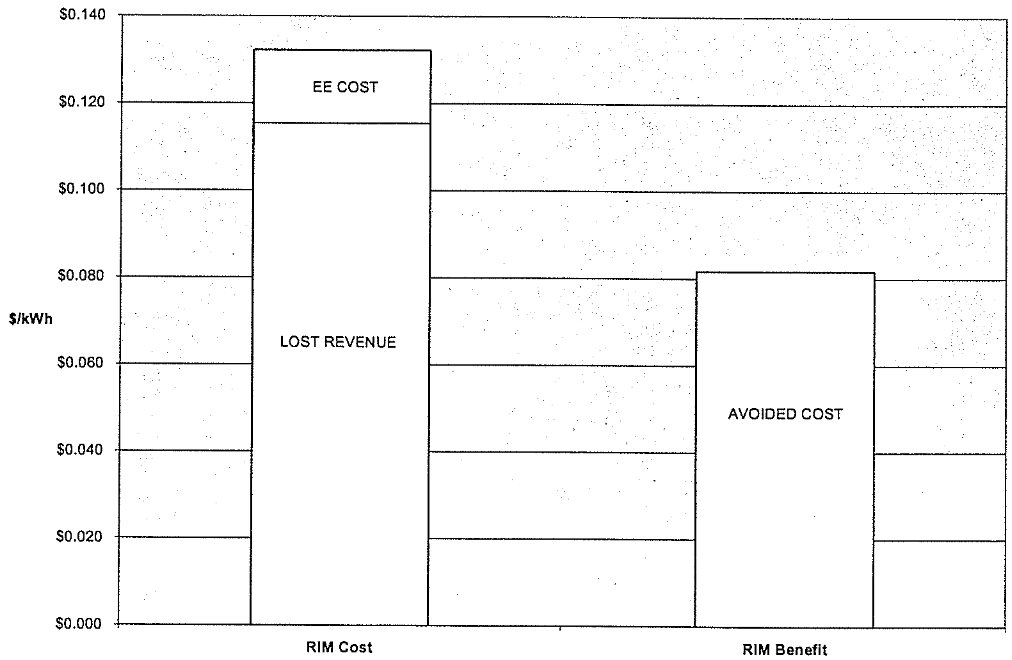


Exhibit IV-21: RIM Test – Small C/I Retrofit

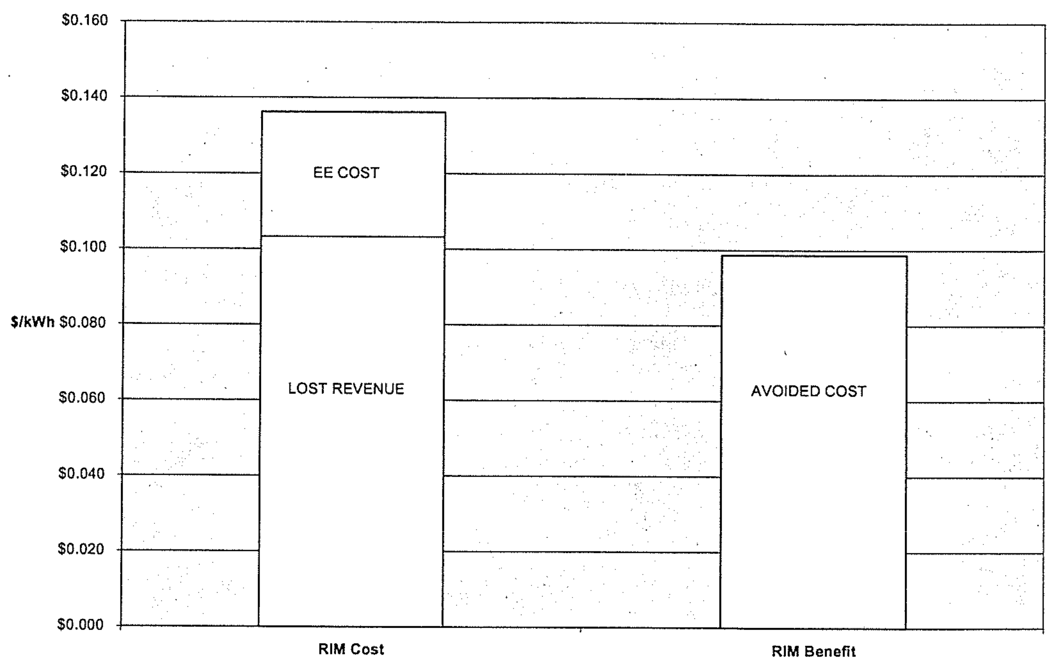
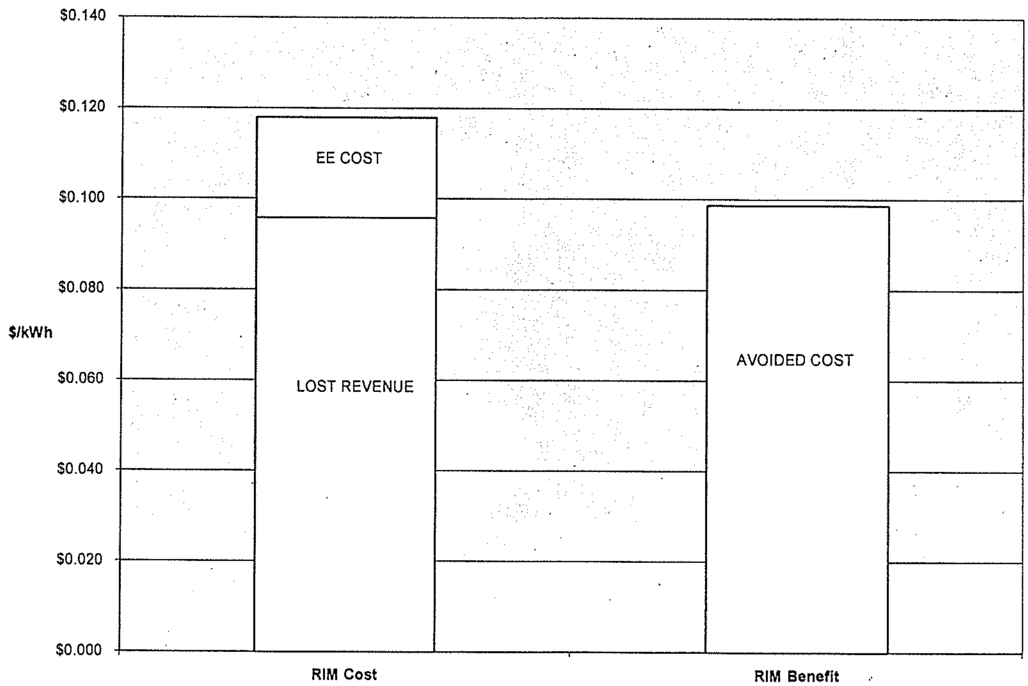


Exhibit IV-22: RIM Test – Large C/I Retrofit



F.5. Conclusions

As directed by the Commission, the purpose of our analyses is to determine the effects of using the RIM test on the availability of demand-side resources. Observations on the results presented in this section include:

- The three programs with the highest benefits and most energy savings as determined by the TRC test failed the RIM test. The conclusion is that use of the RIM test would dramatically reduce the availability of demand-side measures.
- The Residential Lighting and Small Business programs would have failed the RIM test even if the programs could have been implemented at no cost. This is because for these programs Lost Revenues exceed Avoided Costs. The Large C&I Retrofit program also fails the RIM test; however, in this case, Avoided Costs are slightly more than Lost Revenues.
- As noted at the end of Section IV.F.3, the RIM test can disqualify cost-effective measures, and it can qualify other measures which are not cost-effective.
- PSNH supports continued use of its TRC test while recognizing the need for timely distribution rate adjustments to avoid harm to investors from expanded energy efficiency programs.

F.6. Impact of Environmental Regulations on DSM Cost Effectiveness

The avoided cost of electricity used to evaluate Energy Efficiency program cost-effectiveness is based on a long-term forecast of the prices of energy and capacity in the New England wholesale market. The forecasted prices account for the estimated cost of compliance with regulations governing CO_2 emissions. The inclusion of compliance costs in the avoided cost of electricity increases the present value of the economic benefits and accordingly increases the cost-effectiveness of the programs.

G. Research and Development

As part of its ongoing commitment to stay on top of the latest developments in energy efficiency and demand response, PSNH is a founding sponsor and active participant in an Energy Efficiency Initiative being conducted by the Electric Power Research Institute ("EPRI"). EPRI did much of the pioneering R&D in energy efficiency dating back to the early 1980s; however, they have been out of the energy efficiency arena for more than a decade. This initiative which kicked off in January 2007 currently has support from approximately 40 utilities from across the country.

As currently structured, the Initiative covers 28 projects and a wide variety of issues including:

- Development of a comprehensive "how to" guide for energy efficiency and demand response programs. This will be supplemented with "best practices" based on current program offerings from around the country.
- Best practices for integrating energy efficiency/demand response and the transmission and distribution planning functions.
- Development of methodologies and tools for comparing energy efficiency and generation options and for calculating the CO_2 emissions impact of efficiency and demand response.
- A study to assess the energy efficiency and demand response potential. The study is being conducted such that results will be available both regionally and nationally.
- Establishment of the technical requirements and cost/benefits for demand response and advanced metering infrastructure systems and an on-going assessment of the capabilities of commercially available systems. This effort includes the establishment of a full scale laboratory for testing systems and devices.

Many of these projects are underway with delivery dates starting in the fourth quarter of this year. Additional information regarding the initiative can be found online at www.epri.com.

V. Assessment of Supply Resources

This section assesses PSNH's supply resources beginning with an overview of PSNH's diversified mix of generating resources including hydroelectric, coal, oil, natural gas, combustion turbines, as well as purchases from independent power producers and purchased power contracts. This section also outlines PSNH's future renewable power resources and discusses how PSNH creates a balanced portfolio using a mix of owned generation and power purchases.

A. Existing Generation Supply

PSNH's generation supply portfolio is comprised of a balanced mix of resource types including three fossil fuel-fired stations, nine hydroelectric facilities, five fossil fuel combustion turbines and long- and short-term purchased power contracts or rate orders. In 2006, PSNH supplied 73 percent of the energy needs and 71 percent of the capacity needs of its customers using owned generation, IPPs and long-term purchases. PSNH's owned generating facilities can produce more than 1,110 megawatts of electric power. Specific descriptions of PSNH's supply portfolio resources are provided in the sections below.

A.1. Fossil Fuel Generating Resources

PSNH's operates three existing fossil fuel-fired generating stations. Currently Merrimack Station and Schiller Station's two coal fired units are used as base load resources and Newington Station is used as an oil-fired or gas-fired peaking and intermediate resource. Historically, PSNH has relied upon these three stations to meet a major portion of the load requirements of its customers and has continually invested in maintaining the facilities. Equipment such as turbines, blades and generator rotors, boiler components and auxiliary equipment have been installed as required to maintain reliability, and PSNH has demonstrated its commitment to the environment through a very significant and sustained investment in pollution reduction equipment at these stations. Exhibit V-1 describes PSNH's fossil fuel stations. The sections below describe each facility in greater detail.

Exhibit V-1: PSNH's Fossil Fuel Stations

Units	Fuel Type	Winter Capacity Rating (MW)	Summer Capacity Rating (MW)	Energy (MWh) (Avg '02-'06)
Merrimack 1 (MK1)	Coal	114.00	112.50	851,273
Merrimack 2 (MK2)	Coal	321.75	320.00	2,202,824
Schiller (SR4)	Coal/Oil	48.00	47.50	1,160,289
Schiller (SR6)	Coal/Oil	48.58	47.94	302,737
Newington (NT1)	Oil/Gas	400.20	400.20	322,164
Total		**932.53**	**928.14**	**4,839,287**

Merrimack Station

Merrimack Station, located in Bow, New Hampshire, is PSNH's primary base load plant. Merrimack Station has two coal-fired, wet bottom cyclone boilers (MK1 and MK2 or Unit 1 and Unit 2), two combustions turbines (CT1 and CT2) typically operated during periods of highest seasonal peak demand, a temporary auxiliary boiler, an emergency generator and the necessary support equipment to generate electricity.

MK1 began commercial operation in 1960. At full load, Unit 1 consumes approximately 1,000 tons of coal per day. The unit burns crushed coal in the Babcock & Wilcox-designed boiler's three cyclone burners. These cyclones are attached to the front of the boiler and burn the coal efficiently at temperatures in excess of 3,500° F. A regenerative type air heater is employed on Unit 1. Unit 1 produces 815,000 pounds of steam per hour at 1,800 psi and 1,000° F. This steam is supplied to the Westinghouse turbine generator, with one return to the boiler for reheating back to 1,000° F. The turbine generator is a tandem compound design with a double flow low pressure turbine. The turbine consists of 37 stages, and operates at 3,600 rpm. The Westinghouse generator is directly connected to the turbine and produces output of 133,689 kVA at 5,360 amps at a 0.85 power factor. The step-up transformer located outside of the turbine room wall increases the voltage to 115 kV for its interconnection with the New England transmission system in the adjacent switchyard.

MK 2 began commercial operation in 1968. At full load, Unit 2 can consume approximately 3,000 tons of coal per day in a Babcock & Wilcox-designed boiler, with seven cyclone burners, four on the front of the boiler and three on the rear. The same types of crushed coal used in Unit 1 can be used in Unit 2. The universal pressure boiler produces 2,332,000 pounds of steam per hour at 2,400 psi and 1,000°F. Unit 2 employs a tubular air preheater. As with Unit 1, steam is supplied to a Westinghouse turbine. After use in the high pressure turbine section, steam is reheated in the boiler, returning it to a temperature of 1,000° F before being used in the intermediate and low pressure turbine sections. The Unit 2 turbine is of a tandem compound design, with two double flow low pressure sections, and a total of 24 stages. The Westinghouse generator is directly connected to the turbine and produces output of 384,000 kVA at 9,238 amps at a 0.90 power factor. The step-up transformer located outside the turbine room wall increases the voltage to 115 kV for interconnection with the New England transmission system in the adjacent switchyard.

PSNH has aggressively pursued fuel switching and fuel blending at Merrimack Station in order to reduce sulfur dioxide (SO_2) emissions. PSNH is currently blending a mix of low sulfur domestic and foreign coals in order to achieve an effective sulfur content of approximately 1.0 percent to 1.2 percent on each unit. Restricted to coals with inherently-low fusion temperatures, Merrimack Station's fuel supply consists of domestic coal from Pennsylvania, West Virginia, Ohio and Virginia as well as foreign coal, primarily from South America.

More than $50 million has been invested in environmental initiatives at Merrimack Station since 1989. MK1 and MK2 are each equipped with two electrostatic precipitators ("ESPs"), operated in series, for the control of particulate emissions, and a selective catalytic reduction system, for the control of NOx emissions.

MK1 and MK2 were designed and constructed with original ESPs. However, supplemental ESPs were installed on MK1 and MK2 in 1989 and 1998, respectively, significantly reducing particulate emissions even further.

In 1995, MK2 became the first coal-fired utility boiler in the United States to install a selective catalytic reduction ("SCR") system for the reduction of nitrogen oxide (NOx) emissions. In addition, a selective non-catalytic reduction system ("SNCR") was installed on MK1 to reduce NOx emissions. In 1999, in order to achieve even greater NOx emissions reductions, the SNCR on MK1 was replaced with an SCR system. The installation of SCR systems on MK1 and MK2 has resulted in reductions in NOx emissions greater than 85 percent from each unit.

Schiller Station

Schiller Station, located in Portsmouth, New Hampshire, is comprised of three utility boilers (SR4, SR5, and SR6), a combustion turbine presently operating as a load shaving unit (CT1), an emergency generator, a primary coal crusher, and the necessary support equipment to generate electricity. Schiller Station's Unit 5 was recently modified with the construction of a new wood boiler to replace the existing coal/oil boiler and is described in further detail in the Biomass section.

Schiller's steam units have historically served a base load or intermediate load role for NEPOOL. The units have the capability of starting up and shutting down daily if needed, but they have also effectively served in the base load role.

Originally completed in 1949, Schiller Station is PSNH's third largest generating plant. Its three existing units were built in 1952 (Unit 4), 1955 (Unit 5), and 1957 (Unit 6). Units 4 and 5 were originally designed to burn coal, and did so for the first six months of their operation. Both were then converted to burn oil as the primary fuel. Unit 6 was designed to burn oil originally. In 1984, Units 4, 5 and 6 were converted to burn coal. Units 4 and 6 continue to be able to burn coal and/or oil as boiler fuel, making them adaptable to changing fuel markets.

Schiller's coal supply consists of low-cost, low sulfur (typically 1% sulfur or lower) coal from Venezuela and Colombia. Occasionally, domestic coal is delivered by barge to Schiller in order to maintain adequate inventory levels. Due to its boiler characteristics, Schiller Station is better able to burn a wider range of available coals than Merrimack Station.

Schiller Station has undergone millions of dollars in environmental optimizations and improvements over the years. The emission controls for each unit at Schiller Station consists of low-NOx burners, a SNCR system and over fire air system for the reduction of NOx emissions and an ESP for the reduction of particulate emissions.

In 1999, SR4 and SR6 were retrofitted with burner equipment that reduces nitrogen oxide (NOx) emission levels by 50 percent. Subsequently, a selective non-catalytic reduction system and an over fire air system were installed. Further NOx reductions were obtained with burner replacements on Unit 4 in the fall of 2006 and on Unit 6 in the spring of 2007 for total NOx reductions of greater than 70 percent.

Newington Station

Newington Station, located in Newington, New Hampshire, was designed as a peaking unit for quick start up and load change capability. Newington Station is comprised of one utility boiler (NT1), two auxiliary boilers, an emergency generator, and the necessary support equipment to generate electricity.

NT1 is PSNH's largest single generating unit. Newington Unit 1 was originally designed to burn crude oil and No. 6 fuel oil. The unit was designed for fast response and startup, making it an attractive unit for intermediate or daily cycling service.

The station began commercial operation in 1974 and was modified to burn natural gas in 1992. At full load the unit consumes nearly 17,000 barrels of oil per day in the Combustion Engineering-designed tangentially-fired boiler. Four elevations of burners, located in the boiler corners, provide the combustion process for the unit. Newington Unit 1 produces 3 million pounds of steam per hour at 1,800 psi and 950° F. This steam is supplied to a Westinghouse turbine generator, with one return to the boiler for reheating back to 950° F. The turbine generator is of a tandem compound design with a double flow low pressure section. The turbine consists of 18 stages and operates at 3,600 rpm. The Westinghouse generator is directly connected to the turbine and produces output of 24 kV at 12,000 amps at a 0.90 power factor. The step-up transformer located outside the turbine room wall increases the voltage to 345 kV for interconnection with the New England transmission system in the adjacent switchyard.

Emissions reductions at Newington Station began with the installation of new gas lines and burners in 1992. The emissions control system on NT1 includes an ESP, for the reduction of particulate emissions, and various NOx emissions controls including water wall soot blowers, arch blowers, low-NOx burners, a boiler tempering skid and an over fire air system. Employing these various methods, PSNH has been able to reduce the amount of nitrogen oxide emitted by NT1 by more than 50 percent. A new control system and flyash collection system was also installed at Newington Station during its spring 2005 outage.

A.2. Combustion Turbines

PSNH operates five combustion turbines, two of which are standalone. The combustion turbines are utilized to produce power during high demand periods.
Merrimack Station's two combustion turbines operate during periods of highest seasonal peak demand or when quick response in generation is required to maintain electrical system reliability. Schiller Station has a separate combustion turbine, a jet engine capable of burning either AV Jet Kero II or natural gas. The two standalone combustion turbines, Lost Nation and White Lake, are managed by a single management and support organization and are utilized to produce power during high demand periods and/or to maintain electrical system reliability. Exhibit V-2 describes PSNH's five combustion turbines.

Exhibit V-2: PSNH's Combustion Turbines

Name	Winter Capacity Rating (MW)	Summer Capacity Rating (MW)	Energy (MWh) (Avg '02-'06)
Merrimack CT1	21.68	16.83	764
Merrimack CT2	21.30	16.80	682
Schiller CT	18.00	17.00	913
Lost Nation	18.08	14.07	671
White Lake	22.40	17.45	1,115
Total	**101.46**	**82.15**	**4,144**

A.3. Hydroelectric Generating Stations

PSNH owns nine hydroelectric stations with 20 units that supply approximately 4 percent of PSNH's energy needs. Exhibit V-3 summarizes the details surrounding each facility. The hydroelectric facilities are managed by a single management and support organization. Coordinated operation of the units is essential to achieve maximized value. Three of these units share a common waterway, which can impact production output between the sites. In addition, Hooksett Station provides the cooling water impoundment required for once-through cooling of the Merrimack Station.

Smith, Gorham and Canaan hydroelectric generating stations are located in an "Upper Hydro" location. Ayers Island and Eastman Falls hydroelectric generating stations are referred to as the "Middle Hydro" location. Amoskeag, Hooksett, Garvins Falls and Jackman hydroelectric generating stations are located in the "Lower Hydro" area.

Each hydroelectric facility is an unmanned station and is monitored and controlled by supervisory control from the ESCC in Manchester, New Hampshire. Of the nine facilities, eight of them operate under the jurisdiction of FERC licenses. The ninth facility, Jackman Station, is not a FERC-jurisdictional project, but is subject to applicable state regulations. Three of the lower hydro units (Amoskeag, Hooksett and Garvins named the "Merrimack Project") recently received a new 40-year FERC license. Canaan is currently completing the relicensing process. The licenses for four of the hydroelectric facilities operated under FERC licenses are long-lived and expire between 2018 and 2036.

In 2006, a new renewable project was completed at Smith Hydro. The $2.75 million project replaced the water turbine or "runner" with a runner of a new, more efficient design. Smith Hydro, installed in 1948, is PSNH's largest single hydro unit, a 15.85 megawatt plant, located in Berlin, New Hampshire. The project resulted in 8 percent more efficiency as a result of the new runner using less water flow per kilowatt and increasing the annual output of renewable hydro power

Exhibit V-3: PSNH's Licensed Hydroelectric Facilities

Licensed facilities	Winter Capacity Rating (MW)	Summer Capacity Rating (MW)	Energy (MWh) (Avg '02-'06)	License issued	License expiration date	FERC project no.
Amoskeag[14]	17.50	17.50	91,661	2007	2047	1893
Hooksett[15]	1.60	1.60	8,052	2007	2047	1893
Garvins Falls[15]	12.40	12.40	44,549	2007	2047	1893
Eastman Falls	6.47	6.47	26,933	1/26/1988	1/1/2018	2457
Ayers Island	9.08	9.08	44,294	4/1/1996	4/1/2036	2456
Smith	14.92	11.54	91,867	8/1/1994	8/1/2024	2287
Gorham	2.05	2.05	11,415	8/1/1994	8/1/2024	2288
Canaan	1.10	1.10	7,017	8/1/1984	8/1/2009	7528
Jackman[15]	3.46	3.55	9,327	N/A	N/A	N/A
Total	**68.58**	**65.29**	**335,115**			

A.4. Biomass

Schiller Station's Unit 5 (SR 5) was recently modified with the construction of a new wood-fired boiler to replace the existing coal/oil-fired boiler. This modification was complete and the unit was put into commercial operation on December 1, 2006. PSNH replaced a 50 megawatt coal-fired boiler at Schiller Station with a new boiler system which uses wood chips and other clean, low-grade wood materials for fuel. This conversion, named Northern Wood Power ("NWP"), allows PSNH to economically produce cleaner electric energy from environmentally sound renewable resources. Northern Wood Power serves in a base load role.

PSNH's current portfolio of owned and operated power plants uses coal, oil, natural gas and water (hydro) as fuels. Wood-fired generation is one step in providing more diversity to PSNH's fuel mix, and will help ensure a reliable supply of affordable electric energy for customers of PSNH. Exhibit V-4 lists the operating details for PSNH's biomass facility.

Exhibit V-4: PSNH's Biomass Facilities

Name	Winter Capacity Rating (MW)	Summer Capacity Rating (MW)	Energy (MWh) (Avg '06-'06)
Schiller 5 (SR5)	43.29	40.35	175,575
Total	**43.29**	**40.35**	**175,575**

[14] Amoskeag, Hooksett and Garvins Falls are currently covered under one FERC operating license for Merrimack River Project.
[15] On May 26, 1988, FERC issued an order finding that the project is not subject to FERC jurisdiction.

A.4.1. Benefits of Biomass

Reduction in Emissions

Northern Wood Power eliminates thousands of tons of emissions from the environment each year. PSNH's new wood-fired boiler utilizes a state-of-the-art fluidized-bed system, which is recognized as a low-emission advanced combustion technology. Fluidized-bed systems use a heated bed of sand-like material suspended (or "fluidized") within a rising column of air. The scrubbing action of the bed material on the wood chips strips away the carbon dioxide and charred layers that normally form around the fuel. As a result, the rate and efficiency of the combustion process is vastly improved. The fluidized-bed boiler technology, coupled with the inherent environmental advantages of wood, burns fuel more completely and substantially limits the production of nitrogen oxides and other airborne emissions. Compared to its coal-burning predecessor with pollution controls in place, the wood-burning boiler produces about 70 percent less NOx emissions, reduces mercury emissions by about 90 percent, and produces little particulate matter into the atmosphere. The new process virtually eliminates sulfur dioxide (SO_2) emissions, reducing such emissions by about 95 percent.

Meeting Clean Air Goals

Replacing one of the boilers at Schiller Station with a wood-fueled boiler helps PSNH achieve its goals in meeting the requirements of the New Hampshire Clean Power Act and helps the state meet federal Clean Air Standards.

Renewable Energy Certificates

The sale of Renewable Energy Certificates is an important part of the business strategy for Northern Wood Power. The system for buying and selling RECs was established to help encourage the growth of renewable energy in the region. A number of states, including Massachusetts, Connecticut, Rhode Island and most recently New Hampshire, have mandated that their energy suppliers purchase a certain amount of their power from qualified renewable sources.

Electric suppliers without sufficient qualified renewable energy sources can demonstrate that they support renewable energy by purchasing RECs. Electricity from Northern Wood Power will not only serve the needs of New Hampshire customers, but also provide additional supply to satisfy the renewable requirements in this region.

The REC market remains a seller's market, and demand is expected to grow in the foreseeable future. PSNH estimates that Northern Wood Power will generate between 300,000 and 400,000 RECs annually.

A.5. Jointly Owned and Generation Purchased Power Contracts

In addition to the generation resources described above, PSNH holds an ownership interest in Wyman 4 located in Yarmouth, Maine and a power purchase agreement with Vermont Yankee and receives a portion of the power produced by those facilities. Exhibit V-4 describes PSNH's ownership and entitlement contracts.

Exhibit V-5: PSNH's Ownership and Entitlement Contracts

Name	Type	PSNH's Share	Winter Entitlement (MW)	Summer Entitlement (MW)
Vermont Yankee	Nuclear	3.3%	20.62	20.62
Wyman 4	Oil	3.1%	19.13	18.44
Total			**39.75**	**39.06**

A.6. Independent Power Producer Contracts and Rate Orders

Under the Public Utility Regulatory Policies Act ("PURPA"), PSNH is required to interconnect and purchase the generation from Qualifying Facilities ("QF"). The Qualifying Facilities or Independent Power Producer ("IPP") contracts and rate orders include a mix of resources fueled by water, wood, landfill gas and trash and account for 11 percent of PSNH's resource mix. Exhibit V-5 describes PSNH's IPP contract and rate order obligations as of July 2007.

Exhibit V-5: PSNH's IPP Contract and Rate Order Obligations, July 2007

Name	Type	Winter Capacity Rating (MW)	Summer Capacity Rating (MW)	Annual Energy (MWh)	Rate Order/ Contract End Date
Tamworth Power	Wood	21.00	21.00	42,700	Mar-2008
West Hopkinton Hydro	Hydro	1.25	0.46	3,300	Oct-2012
Garland Mill	Hydro	0.00	0.00	33	Nov-2012
Penacook Lower Falls	Hydro	3.44	0.47	18,800	2013
Rollinsford Hydro	Hydro	1.50	1.50	6,000	2013
Great Falls Lower	Hydro	0.84	0.27	3,400	2014
Newfound Hydro	Hydro	1.39	0.93	6,000	2014
Nashua Hydro	Hydro	0.84	0.36	4,300	2014
Steels Pond Hydro	Hydro	0.69	0.15	2,600	2014
Watson Dam	Hydro	0.25	0.09	1,000	2015
Sugar River Hydro	Hydro	0.15	0.06	600	2015
Four Hills Landfill	Landfill Gas	0.63	0.63	4,800	2016
Peterborough Lower Hydro	Hydro	0.28	0.28	900	2018
Peterborough Upper Hydro	Hydro	0.40	0.40	1,100	2018
WES Concord MSW	Trash	12.76	12.52	103,000	2019
Penacook Upper Falls	Hydro	2.85	0.73	13,900	2021

Name	Type	Winter Capacity Rating (MW)	Summer Capacity Rating (MW)	Annual Energy (MWh)	Rate Order/ Contract End Date
Briar Hydro	Hydro	4.96	0.00	21,100	2022
Errol Dam	Hydro	3.00	2.55	17,000	2023
Total Long-Term IPP Contracts and Rate Orders		56.20	42.40	250,533	
Total IPP Replacement Power Contracts		10.00	10.00	75,842	

Note: Capacity Rating is Seasonal Claimed Capacity ("SCC") as reported to ISO-New England.

B. Load Resource Balance

As a load-holding entity, PSNH is responsible for having sufficient energy to meet the hourly needs of its customers and is also required to have sufficient capacity available to satisfy its share of the ISO-New England capacity requirement. PSNH meets its requirements through its owned generation, PURPA-mandated purchases under short term rates and long term rate orders, and through supplemental purchases of energy and capacity from the market. In 2006, PSNH supplied 73 percent of total energy requirements through its owned generation, IPPs and other long-term entitlements and 27 percent through spot market and bilateral energy purchases. Appendix D provides detail on the specific supply resources used to serve PSNH's 2006 energy requirement. In 2006, PSNH supplied 71 percent of total capacity requirements through its owned generation, IPPs and other long-term entitlements (including Hydro-Quebec interconnection capacity credits) and 29 percent through supplemental purchases from other market participants and the ISO-New England administered capacity auctions. Appendix E provides detail on the resources used to serve PSNH's 2006 ISO-New England capacity obligation.

B.1. Existing Power Supply Resource Portfolio

Exhibit V-6 lists the existing generating resource portfolio PSNH will use to serve its customers' energy requirements during the planning period. As shown in the exhibit, PSNH's existing supply resources during this period total about 1,198 MW for the summer months. The portfolio is comprised of the following resource groups:

- Coal (528 MW from Merrimack and Schiller Stations)
- Oil (409 MW from Newington and Wyman-4)
- Hydroelectric (65 MW from nine stations)
- Combustion turbines (82 MW from five units)
- Wood (40 MW from Schiller Unit 5)
- Nuclear (21 MW from the Vermont Yankee purchased power arrangement)
- Non-utility generation (42 MW from IPPs under rate orders or contracts and 10 MW from an IPP replacement contract)

IPPs that may or may not continue to provide power to PSNH under short-term rates are not listed and are not considered PSNH's supply resources for purposes of this planning document.

Exhibit V-6: PSNH Resource Portfolio

Resource	Winter Rating (MW)	Summer Rating (MW)	Interest	Winter Entitlement (MW)	Summer Entitlement (MW)
Amoskeag	17.50	17.50	100%	17.50	17.50
Garvins / Hooksett	14.00	14.00	100%	14.00	14.00
Eastman Falls	6.47	6.47	100%	6.47	6.47
Ayers Island	9.08	9.08	100%	9.08	9.08
Smith	14.92	11.54	100%	14.92	11.54
Gorham	2.05	2.05	100%	2.05	2.05
Canaan	1.10	1.10	100%	1.10	1.10
Jackman	3.46	3.55	100%	3.46	3.55
Vermont Yankee	620.25	620.25	3.3%	20.62	20.62
Merrimack Unit 1	114.00	112.50	100%	114.00	112.50
Merrimack Unit 2	321.75	320.00	100%	321.75	320.00
Schiller Unit 4	48.00	47.50	100%	48.00	47.50
Schiller Unit 6	48.58	47.94	100%	48.58	47.94
Schiller Unit 5	43.29	40.35	100%	43.29	40.35
Newington[16]	400.20	400.20	97.5%	390.36	390.36
Wyman 4	608.58	586.73	3.1%	19.13	18.44
Merrimack CT1	21.68	16.83	100%	21.68	16.83
Merrimack CT2	21.30	16.80	100%	21.30	16.80
Schiller CT	18.00	17.00	100%	18.00	17.00
Lost Nation	18.08	14.07	100%	18.08	14.07
White Lake	22.40	17.45	100%	22.40	17.45
Tamworth Power	21.00	21.00	100%	21.00	21.00
West Hopkinton Hydro	1.25	0.46	100%	1.25	0.46
Garland Mill	0.00	0.00	100%	0.00	0.00
Penacook Lower Falls	3.44	0.47	100%	3.44	0.47
Rollinsford Hydro	1.50	1.50	100%	1.50	1.50
Great Falls Lower	0.84	0.27	100%	0.84	0.27
Newfound Hydro	1.39	0.93	100%	1.39	0.93
Nashua Hydro	0.84	0.36	100%	0.84	0.36
Steels Pond Hydro	0.69	0.15	100%	0.69	0.15
Watson Dam	0.25	0.09	100%	0.25	0.09
Sugar River Hydro	0.15	0.06	100%	0.15	0.06
Four Hills Landfill	0.63	0.63	100%	0.63	0.63
Peterborough Lower Hydro	0.28	0.28	100%	0.28	0.28
Peterborough Upper Hydro	0.40	0.40	100%	0.40	0.40
WES Concord MSW	12.76	12.52	100%	12.76	12.52
Penacook Upper Falls	2.85	0.73	100%	2.85	0.73
Briar Hydro	4.96	0.00	100%	4.96	0.00
Errol Dam	3.00	2.55	100%	3.00	2.55
IPP Replacement	10.00	10.00	100%	10.00	10.00
Totals				1241.99	1197.52

[16] Ownership contract with Unitil expires October 2008 at which point PSNH will retain 100 percent interest.

B.2. Forecast of Energy Requirement and Supply Resources

Exhibit D-2 in Appendix D provides a forecast of the energy production from existing supply resources during each year of the planning period. The exhibit also lists the expiration date of the IPPs under rate order and the forecast of PSNH's energy requirement. Exhibits D-3 and D-4 in Appendix D provide the same information, but with the annual quantities separated into on-peak and off-peak categories. Other than Newington Station and the combustion turbines, all supply resources operate as baseload assets, taking into account historical availabilities, 20-year hydro averages, and anticipated maintenance. In the exhibits, the CTs are assumed to provide zero MWh, but in reality provide an important source of reserves and energy during peak load and/or high price hours.

Newington Station's production shown in the exhibits is a result of operating at various output levels only during the on-peak hours in the months of January, February, July and August. This is based on a recent review of Newington's forecasted economics relative to market-based purchases which indicate customer savings during the noted months.

The conclusion from Exhibit D-2 in Appendix D is that PSNH has a forecasted supplemental energy requirement that ranges from 4,041 GWH in 2008 (approximately 45 percent of total energy requirement) to 5,105 GWH in 2012 (approximately 52 percent of the total). It is more informative, however, to examine the supplemental requirement in terms of on-peak and off-peak periods. Exhibit D-3 in Appendix D indicates an on-peak supply deficiency of 2,395 GWH in 2008 and 2,931 GWH in 2012. The off-peak deficiencies from Exhibit D-4 in Appendix D are 1,646 GWH in 2008 and 2,174 GWH in 2012.

To further examine the on-peak deficiency noted in Exhibit D-3 in Appendix D, assume that Newington is available to provide approximately 400 MWh of energy during each on-peak hour. While Newington may not be the most economic choice in all on-peak hours, from a long-term planning perspective, it is assumed to be either operating or on economic reserve and, thus, providing an upper limit or hedge to supplemental energy expenses. If Newington's full production capability is factored into the energy deficiency, the average on-peak supplemental need is significantly reduced. As shown on Exhibit D-3 in Appendix D, with Newington available at 400 MW, the average on-peak deficiency during the planning period ranges from 249 MW to 355 MW.

Exhibit D-4 in Appendix D provides the average deficiencies during the off-peak hours and assuming Newington is not utilized (i.e., provides zero off-peak energy based on economics). These off-peak deficiencies range from 351 MW to 464 MW. Exhibit V-7 shows the total energy requirement balance in a graphical form.

Exhibit V-7: PSNH Energy Balance

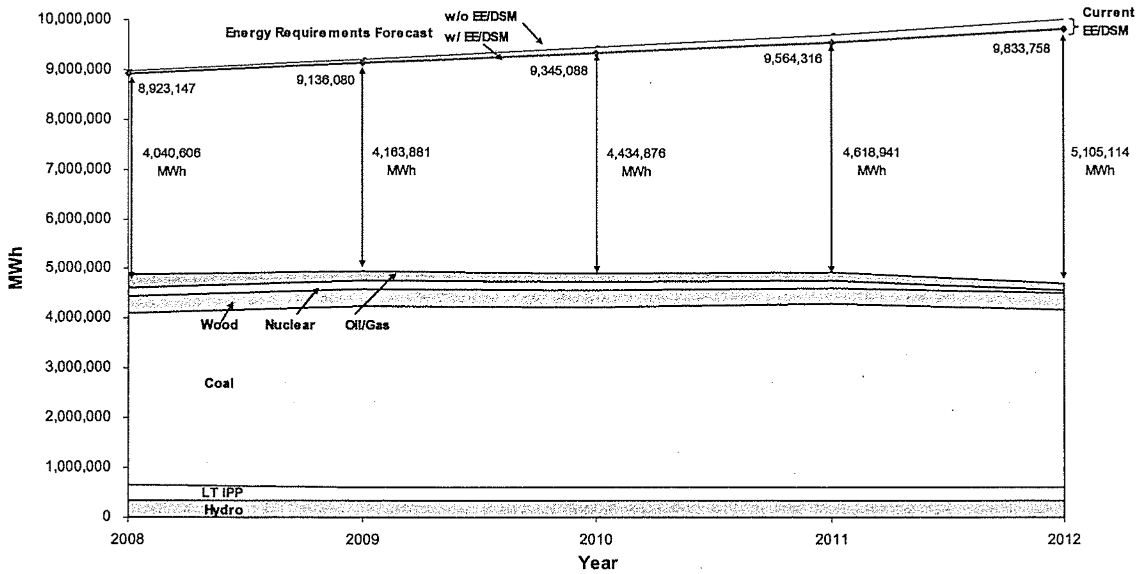


Exhibit V-8 provides an on-peak hourly load duration curve for both 2008 and 2012. The total of all supply resources indicates the average level of production from existing supply resources (see Exhibit D-3 in Appendix D) after removing Newington's contribution to the total. Instead, Newington is shown separately as 400 MW of available energy production. The curve can be used to visualize the extent of PSNH's on-peak energy deficiency. A note has been added to the highest 100 load hours to indicate the type of service anticipated from PSNH's five combustion turbines that are capable of providing 82 MW during extreme ISO-New England load and/or price events. Exhibit V-9 provides an off-peak hourly load duration curve.

Exhibit V-8: PSNH On-Peak Load and Generation

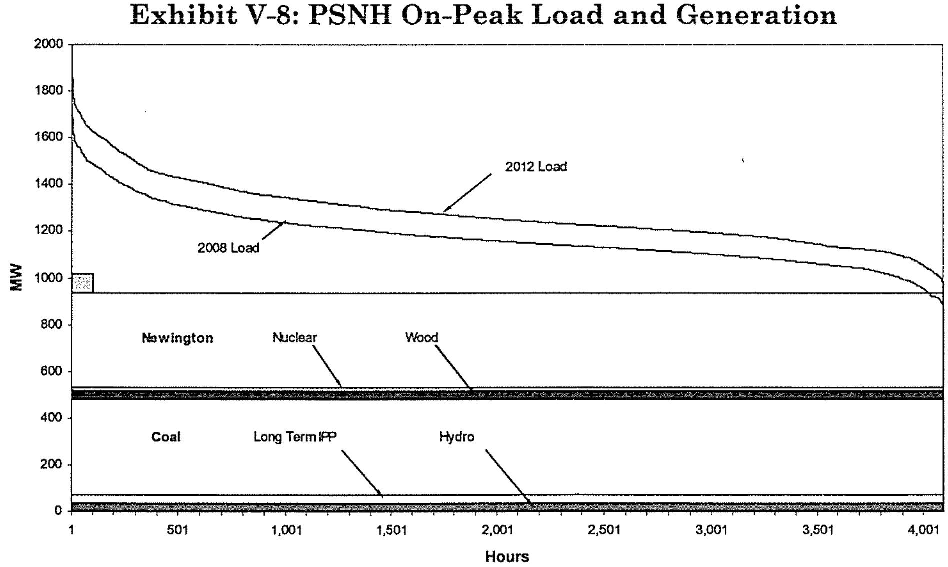
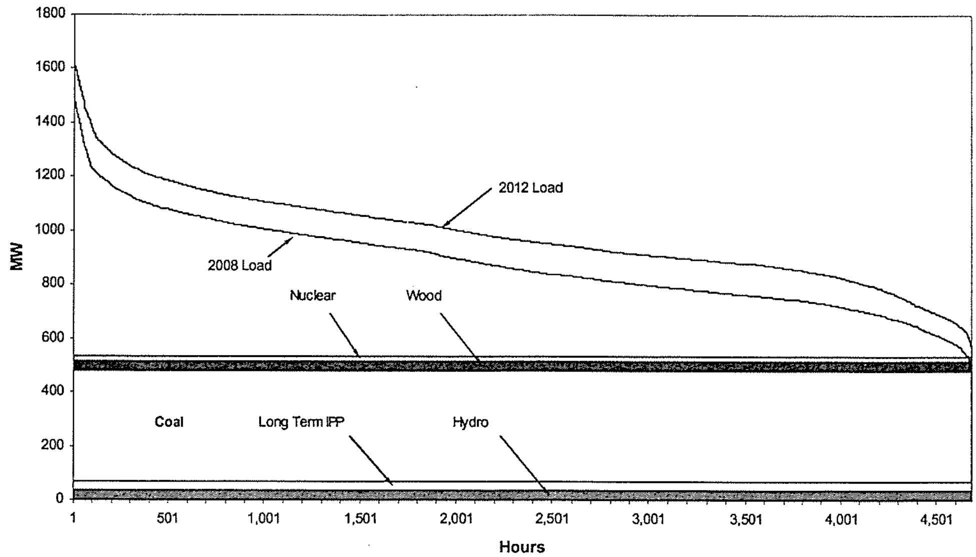


Exhibit V-9: PSNH Off-Peak Load and Generation



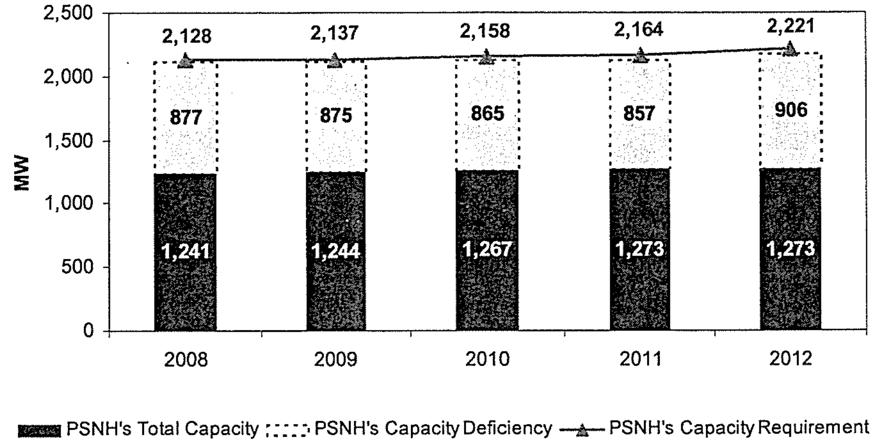
B.3. Forecast of Capacity Requirement and Supply Resources

Exhibit V-10 provides a forecast of PSNH's annual average capacity requirement during 2008 through 2012 based on PSNH's share of ISO-New England's forecast of total required capacity. Exhibits F-1 and F-2 in Appendix F provide monthly details and the analytical assumptions that support the annual results. Exhibit F-1 in Appendix F is an assessment of PSNH's capacity balance during the Transition Period Capacity Market rules, which terminate May 2010. Exhibit F-2 in Appendix F is a review of the capacity balance forecast under the Forward Capacity Market rules, which are applicable starting in June 2010. PSNH's capacity supply forecast is based on the assets listed in Exhibit V-6, as adjusted to account for the expiration dates of certain IPPs and the monthly schedule of Hydro-Quebec interconnection credits. Exhibit V-11 shows the deficiency in a graphical form.

Exhibit V-10: Forecasted Capacity Requirement

	2008	2009	2010	2011	2012
Total ISO-New England Supported Capacity (MW)	33,224	33,224	33,413	33,371	33,995
PSNH's Share of ISO-New England Peak (%)	6.41%	6.43%	6.46%	6.48%	6.53%
PSNH's Share of Supported Capacity (MW)	2,128	2,137	2,158	2,164	2,221
Total PSNH Supply Resource Capacity (MW)	1,241	1,244	1,267	1,273	1,273
PSNH's Demand Resources (MW)	10	18	26	34	42
PSNH's Capacity Deficiency (MW)	877	875	865	857	906
% Deficiency	41%	41%	40%	40%	41%

Exhibit V-11: Forecasted Capacity Requirement



B.4. Fuel Supply and Diversity

During the last few years, the energy commodities markets (gas and oil) have experienced significant and sustained price volatility and a general upward trend in price. Even coal, a commodity with a fairly stable price history, has increased in price. Exhibit V-12 provides annual average fuel prices reported in the U.S. since 1990.

Exhibit V-12: Commodity Price History

	Natural Gas ($/Thousand Cubic Feet)	Residual Fuel Oil 1% or less Sulfur ($/Barrel)	Bituminous Coal ($/Short Ton)
1990	2.38	21.50	27.43
1991	2.18	16.80	27.49
1992	2.36	16.55	26.78
1993	2.61	16.51	26.15
1994	2.28	16.93	25.68
1995	2.02	18.19	25.56
1996	2.69	22.22	25.17
1997	2.78	19.82	24.64
1998	2.40	14.95	24.87
1999	2.62	17.05	23.92
2000	4.38	28.69	24.15
2001	4.61	26.04	25.36
2002	3.68	25.70	26.57
2003	5.57	32.97	26.73
2004	6.11	33.35	30.56
2005	8.48	48.22	36.80
2006	7.09	55.52	37.51

Source: Energy Information Administration
Notes:

- All prices in Nominal dollars
- EIA Natural Gas prices reported for "Electric Power Sector"
- EIA Residual Oil prices reported for "Sales Price to End Users"
- EIA Coal prices reported exclude transportation

In addition, strained gas pipeline supply capacity and increased demand for coal rail transportation have caused New England prices to climb higher than prices in areas of the country without such deliverability issues. Around New England, the commodity price increases have resulted in higher marginal generation expenses and higher risk premiums which are passed along to consumers via retail electric rates. Electric distribution companies that have divested their generation as part of industry restructuring are exposed to the full impact of these price increases via their total reliance on supplying their customers' energy needs from market-based sources. PSNH's ownership of a diverse portfolio of generation supply resources serves to reduce the impacts of commodity price volatility.

During 2006, approximately 55 percent of PSNH's energy requirements were met with coal, wood, hydroelectric and nuclear resources. The coal-fired generation utilized fixed-price coal under long-term contracts, thus resulting in marginal production costs well below market replacement alternatives. Similarly, PSNH's hydroelectric facilities and the fixed-price Vermont Yankee purchased power contract provide power without any exposure to commodity price fluctuations. Newington Station is capable of operating on either residual oil or natural gas. Because of the diversity of its supply portfolio, PSNH is largely insulated from the extreme volatility of the natural gas market. Even during periods of high and volatile natural gas prices, PSNH's diversified resource mix provides relative price stability.

B.5. Fuel Procurement Strategies

PSNH utilizes a fuel procurement strategy that is driven by emission constraints associated with state and federal regulations and State Operating Permits, generating unit operations and fuel costs. Fuel for PSNH's generating stations is procured on a lowest-evaluated cost basis, which takes into account such factors as commodity price, transportation (logistics and price), heat (BTUs) and ash content, and elemental constituents (sulfur, mercury, etc.).

An annual fuel and emission planning meeting is held with Fuel Department personnel, PSNH Generation staff, and station managers. An additional eight to ten meetings occur throughout the remainder of the year to review year-to-date emissions, fuel procurement activity and delivery topics, station capacity factors to-date, and projected emission rates and capacity factors for the remainder of the year, as well as discussions regarding short- and long-term emissions compliance and fuel procurement scenarios.

Coal

PSNH's base load coal plants burn approximately 1.5 million tons of permit-required bituminous coal per year and provide the most challenge to fuel procurement. Environmental constraints and the limited number of coal types with the right characteristics to be successfully burned at PSNH's generating stations combine to limit the breadth of portfolio of supplies that could be solicited from the market. Specific types and tonnages of coal to be purchased, inventoried, and burned are extensively examined. PSNH has aggressively canvassed the global marketplace in search of fuels that can be reliably burned in PSNH's boilers, while meeting the increasingly restrictive emissions requirements in the most cost-effective manner.

Transportation logistics also play a key factor in determining the fuel sources supplied to each station. Fuel delivered to Schiller Station and Newington Station is transported via ocean-going marine vessels, while Merrimack Station is served via rail and is supplemented by truck service (transshipped from marine vessels).

PSNH typically issues Request-For-Proposals ("RFPs") for the majority of its coal supply and supplements the variety of multi-year contracts with spot purchases. Spot purchases can be used to resolve force majuere events, delivery delays, fuel quality variations, capacity factor variations, etc.

Due to its boiler characteristics, Schiller Station is able to burn a wider range of available coals than Merrimack Station, which is restricted to coals with inherently-low fusion temperatures. Schiller Station has been supplied with low-cost, low sulfur (typically 1 percent sulfur or lower) coal from Venezuela and Colombia delivered by handy-size ships (in cargo lot sizes of 30,000 to 40,000 tons). Occasionally, barges of domestic coal are interspersed into Schiller Station in order to maintain adequate inventory levels as required. It is anticipated that Schiller Station will continue to be supplied with offshore coal in the foreseeable future.

Merrimack Station has aggressively pursued fuel switching and tested a variety of fuel blends in order to comply with state and federal regulations. It is currently blending a mix of domestic and foreign coals in order to achieve a blended sulfur content of approximately 1.1 to 1.3 percent on each unit. Merrimack Station is supplied with low fusion temperature domestic coal from northern Appalachia, namely Pittsburgh seam coal located in southwestern Pennsylvania. It also receives coal originating in central Appalachia. These coals are typically procured using term agreements and, as necessary, purchased in the spot market to supplement the term purchases. Rail service is a two- or three-line haul and determines 40 to 50 percent of the delivered cost of Merrimack Station's coal supply. Merrimack Station has been able to take advantage of the favorable offshore coal prices by transshipping a large percentage of its coal requirements through Schiller Station. This coal is transshipped through Schiller Station's coal yard and is delivered to Merrimack Station via truck service. The cost savings of using foreign coal, as compared to displacing and burning higher priced domestic coal of similar quality is significant. It is expected that the current supply sources will continue for Merrimack Station into the foreseeable future.

Oil

Newington Station has played the role of the 'swing' station in terms of allowing PSNH to meet its emissions targets, with Newington Station burning natural gas and/or a blend of residual oil (up to 2 percent sulfur) as necessary. When a substantial margin to the emission caps exists, Newington Station is free to dispatch on either oil or natural gas, dependant on ISO-New England market clearing prices, commodity price differentials and system electrical supply and demand. Fuel oil is procured via pre-scheduled cargos or barges based on forecasted utilization.

Wood

Wood is the newest fuel procurement effort undertaken by PSNH with the installation of the new wood boiler (Unit 5) at Schiller Station, known as Northern Wood Power. The procurement process begins with an estimation of the fuel requirements of Northern Wood Power on an annual, weekly, and daily basis. Contracts for ten to fifteen percent more volume than the anticipated need are entered into with various suppliers. The surplus volume is required in order to offset delivery disruptions due to inclement weather, mechanical breakdowns, or supplier interruptions. Wood is procured in accordance with the agreement between PSNH and the New Hampshire Timberline Owners Association ("NHTOA"). All wood must meet the NWP boiler specifications and permit obligations. All wood suppliers are required to enter into a purchase and sales contract with PSNH for the delivery of wood and every supplier is given a copy of the city of Portsmouth Truck Management Plan and a copy of the PSNH Random Vehicle Search Procedure.

B.5.1. Fuel Inventory Management

Fuel inventory levels at PSNH's electric generating stations are optimized between fuel supply reliability and carrying costs. The overriding goal is to maintain sufficient supply quantities on hand to meet anticipated generation needs at all times. Merrimack and Schiller Stations' minimum coal inventory levels are targeted to certain levels that are recommended by the New Hampshire PUC. The targeted levels are 45 days and 30 days supply, respectively, for Merrimack and Schiller. PSNH manages Merrimack Station's inventory level by coordinating 90-car train sets, and trucking foreign coal from the New Hampshire coast out of Schiller Station's coal yard and continually projecting the station's capacity factor months in advance.

Ten to twenty days of full-burn equivalent of residual oil is maintained in inventory on-site at Newington Station.

B.6. Supplemental Purchase Procurement Strategy

Section III described the process by which PSNH identifies a targeted set of block purchases to meet the hourly energy and capacity requirements for PSNH's Energy Service customers. This section discusses the general process of procuring the targeted purchase quantities.

PSNH's current procurement plan is focused primarily on the subsequent annual period. For example, during 2007, plans will be developed and executed to manage forecasted power supply needs for 2008. The goal of the plan is to assemble a portfolio of purchases that, when combined with existing generation assets and previously executed fuel and power arrangements, will enable PSNH to establish a fixed annual Energy Service rate that is subject to minimal risk of significant under-recovery or over-recovery.

The initial purchase targets are typically established in March or April of the prior year. The purchase plan is reviewed with PSNH's management and a procurement schedule is developed that typically calls for purchasing to be conducted in multiple phases during May through the filing date of the final rate forecast (normally in November). This purchase strategy is subject to continuous internal review and may be revised to account for market movement, the availability of supplies, and the forecasted utilization of Newington Station (which fluctuates based on the relative pricing of oil versus purchased power).

The typical products that PSNH utilizes to serve the supplemental requirement are:

> **1) Fixed-price, forward bilateral contracts for "strips" of energy** (i.e., a uniform amount of energy in each hour of the relevant contract period). These are procured in on-peak strips (Non-holiday, Mon - Fri from hour-ending 8 am to 11pm), off-peak strips (all other hours), and weekend peak strips (Sat and Sun from hour-ending 8 am to 11pm). Typical contract duration ranges from a single day to multiple months. Monthly or multi-month contracts are typically procured from 3 to 12 or more months prior to contract delivery. Single day and weekly contracts are typically utilized to fine-tune the energy position and are procured within a few days of contract delivery.
>
> **2) Fixed-price, forward bilateral contracts for capacity.** These contracts provide a certain MW quantity of capacity that is used to satisfy PSNH's ISO-New England capacity obligation in a given month. Typical contract duration is a single month, a single calendar quarter, or a calendar year. These contracts are typically procured from 3 to 12 or more months prior to contract delivery. Single month contracts may also be procured in the days or weeks just prior to the delivery month to fine-tune the capacity position. Note: during the Transition Period prior to the Forward Capacity Market (i.e., December 2006 – May 2010) fixed-price, bilateral capacity contracts are no longer applicable. Capacity deficiency charges are incurred via an administrative process that effectively amounts to a fixed charge of $3,050 per MW-month (December 2006 through May 2008), $3,750 per MW-month (June 2008 through May 2009) and $4,100 per MW-month (June 2009 through May 2010).

As noted above, PSNH's goal is to establish a relatively firm power supply and to file an accurate forecast of the cost to provide energy service for the coming year. As such, PSNH's general approach is to minimize spot market purchases by procuring fixed-price supplemental power and avoiding exposure to spot market uncertainty and volatility. This approach is discussed and reviewed in the applicable rate setting proceeding.

The decision to buy forward for a future period or to purchase from the spot market requires a qualitative assessment of a number of uncertain factors, including:

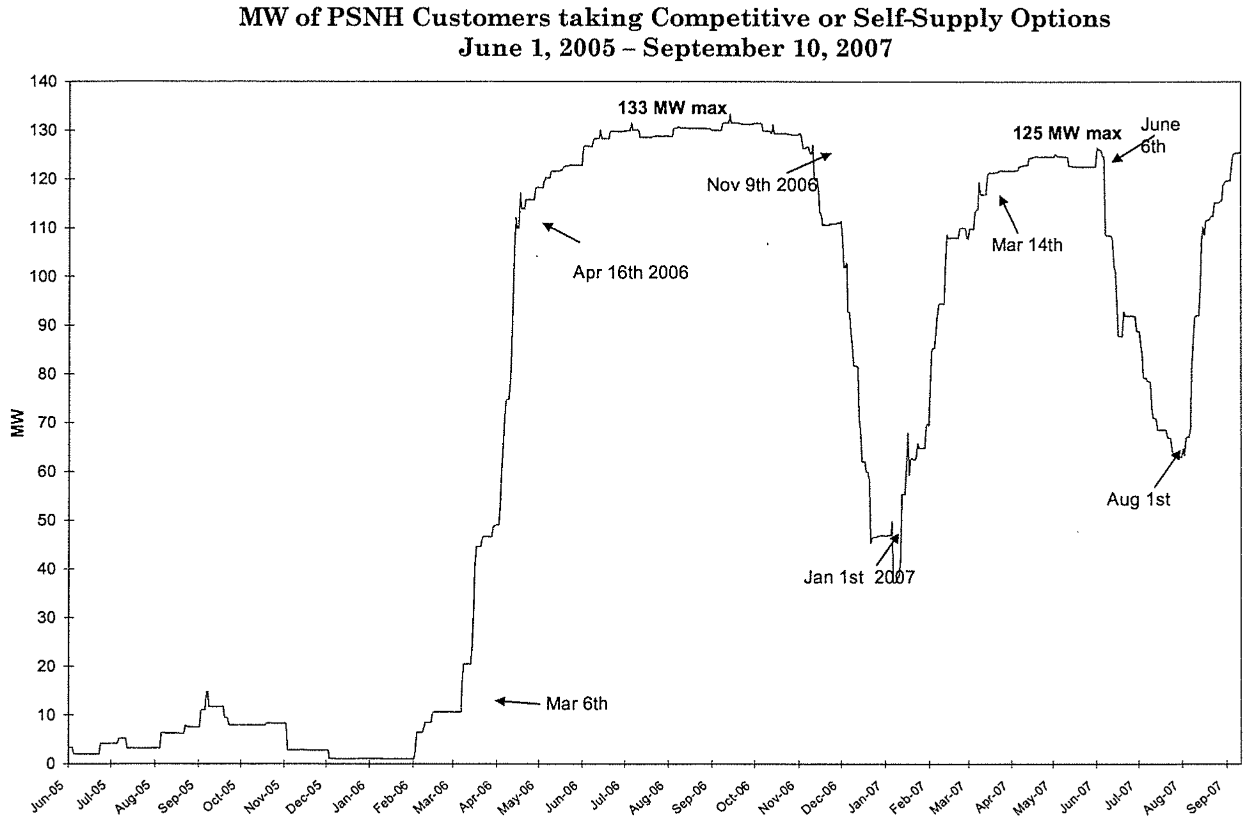
- Available market intelligence regarding anticipated commodity price movement
- Historical and expected spot market volatility within the future period
- Forecasted purchase requirement
- Risk-tolerance of the purchaser
- Availability of competitively priced supply options

Periodic meetings are held with PSNH's senior management to review all of these factors and to make decisions regarding how PSNH will supply energy during upcoming periods. Such review includes discussions of whether to operate Newington Station or to purchase energy for particular months to replace Newington's output, and the amount and duration of purchases.

B.6.1. Customer Migration

Another factor that must be considered in the procurement plan is customer migration to competitive supply. Exhibit V-14 is a graph of the MWs of annual peak demand associated with the specific customers that were not receiving Energy Service from PSNH. As shown, there have been two recent periods during which competitive suppliers were able to sign contracts with customers representing a significant quantity of PSNH's energy requirements. The first period began in late winter of 2006 and the majority of the contracts appear to have expired prior to the end of 2006 as shown by the rapid decrease in the migrated megawatts during November and December 2006. The second opportunity occurred in early winter 2007. During both periods, the total migrated demand was in the range of 125 to 133 MW, representing close to 8 percent of PSNH's peak demand. The exhibit also shows the return to Energy Service that occurred during June and July of 2007. It is not yet known the extent of this return and/or whether the future pattern of migration will be predictable.

Exhibit V-14: Energy Service Customer Migration History



B.6.2. PSNH's Hedging Strategy

PSNH seeks to limit exposure to the ISO-New England hourly spot market, both as a purchaser and as a seller. For example, if PSNH were to fully hedge 100 percent of the forecasted supplemental energy requirement with fixed-price bilateral contracts, and subsequently experienced significant customer migration; PSNH would be surplus in many hours. The surplus power would be resold into the ISO-New England spot market; perhaps at a loss if the resale price is lower than initial purchase price. In fact, a loss on resale is the most likely result, as migration activity is more apt to accelerate during a softening of the energy market.

To address this risk during 2007, PSNH elected to hedge a portion of the forecasted supplemental requirement with an energy call option, rather than with a fixed-price bilateral purchase. In exchange for a negotiated premium, a call option provides the buyer with the right, but not the obligation, to purchase forward energy contracts on a certain future date at a negotiated, fixed strike price. In this way, the buyer can delay the purchase decision, but still obtain price certainty. On the call option expiration date, the buyer would elect to exercise the purchase if the current market price for such power was higher than the strike price. In the case of PSNH, if customer migration had occurred, the power would not be needed to serve customers, but could be immediately resold for a profit that would recover of portion of the premium. If migration had not occurred, PSNH would retain the power to serve customers at the fixed price. PSNH will pursue the call option and other alternatives to address potential migration in future planning periods.

B.7. New Generation Supply Options

PSNH's energy consumption is expected to grow about 2.3 percent per year while PSNH's system peak demand is expected to grow 2.5 percent per year over the planning period. In addition, the newly enacted New Hampshire Renewable Portfolio Standard requires PSNH to supply a portion of its customers' energy requirements from renewable sources and the percentage of renewable sources increases over time through 2025. However, PSNH owned generation resources are presently fixed due to State policy restrictions on the expansion of utility-owned generation resources and expiring purchased power contracts. As a result, PSNH will become increasingly more dependent on the market to meet its customers' needs.

To meet the projected energy requirements, PSNH will need to purchase 4-5 million MWh per year in the open market over the planning period and will need to procure between 900 and 1,000 MW per year of capacity either in the ISO-New England Forward Capacity Market or through bilateral capacity contracts over the planning period. Additionally, PSNH will be increasingly short of supply of RECs to meet New Hampshire's Renewable Portfolio Standard requirements and will be required to either purchase RECs from qualified facilities or make Alternative Compliance Payments to the state for the renewable resource deficiency. See section X for a more detailed discussion of PSNH's compliance with the New Hampshire Renewable Portfolio Standard.

There are a few ways in which these resource gaps can be filled. ISO-New England recently issued its own "New England Electricity Scenario Analysis[17]", which identified a comprehensive array of options to meet future New England resource requirements. While many parallels exist between the ISO-New England's scenario report and PSNH's resource requirement situation, PSNH feels that some of the options defined by ISO-New England are not feasible for PSNH, given the current permitting environment in New Hampshire, environmental regulations, or desire to finance, own and operate a facility of that nature.

The list of supply options that could be used, with supportive State policy, to fill the resource gap include:

- Nuclear base load power plant
- Coal-fired base load power plant
- 50 MW wood-fired base load power plant
- Natural gas-fired combined-cycle intermediate duty plant

[17] ISO-New England's "New England Electricity Scenario Analysis", August 2, 2007 - http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf

- 20-25 MW peaking unit on the distribution system

- Small scale renewable (solar, wind, fuel cell) generation assets

- Contract for purchase of output from merchant generators on other than short-term (one year or less) arrangements

PSNH has dismissed three of the options listed above (nuclear base load power plant, coal-fired base load power plant and natural gas-fired combined-cycle intermediate duty plant) due to the fact that they are not well suited for PSNH's resource requirements or are not well aligned with PSNH's role as a regulated provider of energy service.

The nuclear and coal-fired plant options have been dismissed for the following reasons:

- The size of a typical nuclear (1,000+ MW) or coal-fired power plant (600+ MW) exceeds PSNH's off-peak load requirements

- Capital costs for construction of such assets would be very substantial and place a financial burden on PSNH

- Siting and permitting requirements and duration are thought to be exceedingly difficult in the current environment

The combined cycle natural gas fired (500-750 MW) plant option was dismissed for the following reasons:

- As described in the ISO-New England Scenario Analysis report, it is expected that combined-cycle natural gas plants will continue to be the units at the margin and setting the market clearing price. With high variability and volatility of natural gas prices historically, and absent a reason to expect a change in the future, it is unlikely that a regulated generator could assure savings for customers with such an asset.

- While the combined-cycle intermediate duty plant is a smaller size and has lower capital costs than a nuclear or coal-fired base load plant, the capital costs for constructing a new typical combined-cycle intermediate duty plant would be substantial and place a financial burden on the operations of PSNH.

To the extent New Hampshire State policy would allow, PSNH would propose a portfolio of potential supply side options from the remaining list of alternatives, in blocks of approximately 50 MW or less, depending on resource type consisting of:

- One or two new 50 MW biomass facilities, providing energy, capacity, and RECs

- Up to three 20-25 MW sized distribution level peaking generators (total of 60 to 75 MW of capacity), providing capacity value and limited energy value mitigating high energy costs during times of high peak demand

- Up to 12 MW of solar photovoltaic installations, connected to PSNH's distribution system, providing energy, RECs, and limited capacity value, matching the Class II New Hampshire RPS requirements

- Up to 150 MW of wind turbines, connected to PSNH's distribution system, providing energy, RECs, and limited capacity value

PSNH will also explore opportunities to increase its supply base through contracts for durations of greater than one-year from merchant generators, providing energy, capacity, and Renewable Energy Certificates if eligible.

B.7.1. New Generation Supply Options Analysis

An analysis of each project PSNH deemed appropriate for its consideration using a weighted criteria analysis system to rank the projects according to cost and to determine the supply options to pursue further and include in a potential portfolio. The criteria included in the analysis were:

- Net revenue requirements
- Environmental compliance costs
- Fuel diversity
- Availability at time of system peak
- Promotion of system stability

A weight was assigned to the criteria based on a subjective analysis by PSNH as to which criteria were the most important in keeping customers' costs low. PSNH analyzed two time horizons – the 5-year planning horizon of 2008-2012 and the project life planning horizon to calculate the net present value of revenue requirements. The two planning horizons were used because the 5-year planning horizon is short-sighted for a long-term project and would provide information that may be incorrect for a long-term planning decision. For the revenue requirements criteria, a net present value of revenue requirements was performed for each project and compared to the net present value of market purchases, the current method used to fill PSNH's resource gap. The remaining criteria were analyzed and given a subjective high, medium, and low rating in the weighted criteria analysis and a final determination of project rank was concluded based on this analysis. Exhibit V-15 lists the ordered rank of projects based on the criteria analysis. Appendix G provides more detail about the weights used to develop the final project ranking.

Exhibit V-15: Project Ranking

Project	Rank
50 MW Biomass Plant	2
20 MW Distribution Level Peaking Units	3
Solar PV – w/ Business Energy Tax Credit (BETC)	1
Solar PV – w/o Business Energy Tax Credit (BETC)	4
Wind Project	1

Exhibits V-16 through V-20 graphically show the comparison of the net revenue requirements and the market purchases for each of the projects considered. Net revenue requirements include the estimated cost of the asset and fuel costs, if applicable, reduced for ISO-New England capacity market revenues, REC revenues and tax credits, if applicable. A high and low range was developed to account for higher and lower capital costs. The market purchase costs consist of the energy market value of the associated output from the generation asset. A range of high and a low market purchase costs were developed using the high and low on-peak and off-peak market prices presented in Appendix G, Exhibit G-13.

Exhibit V-16: Biomass Plant – Net Revenue Requirements Compared to Market Purchases

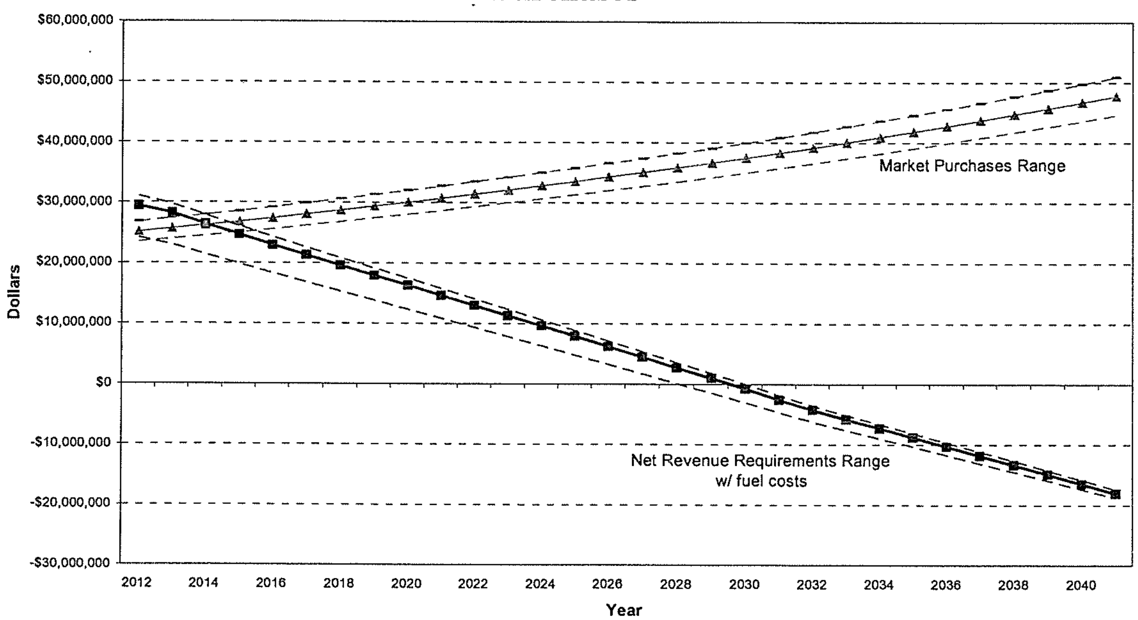


Exhibit V-17: Peaking Unit – Net Revenue Requirements Compared to Market Purchases

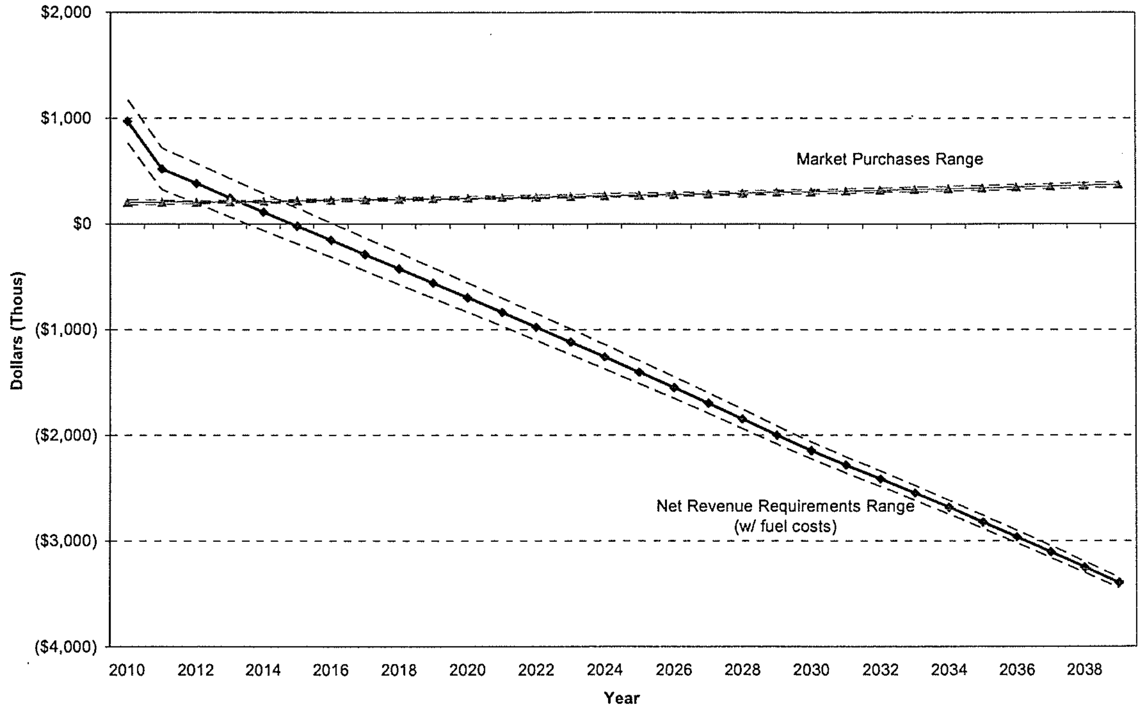


Exhibit V-18: Solar Photovoltaic without BETC – Net Revenue Requirements Compared to Market Purchases

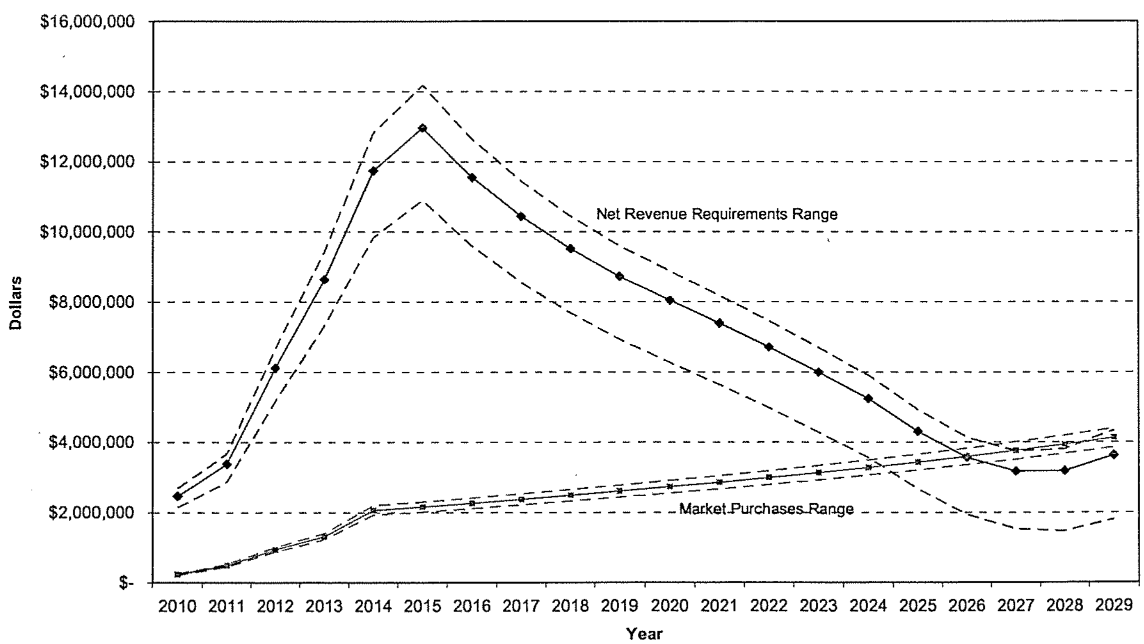


Exhibit V-19: Solar Photovoltaic with BETC – Net Revenue Requirements Compared to Market Purchases

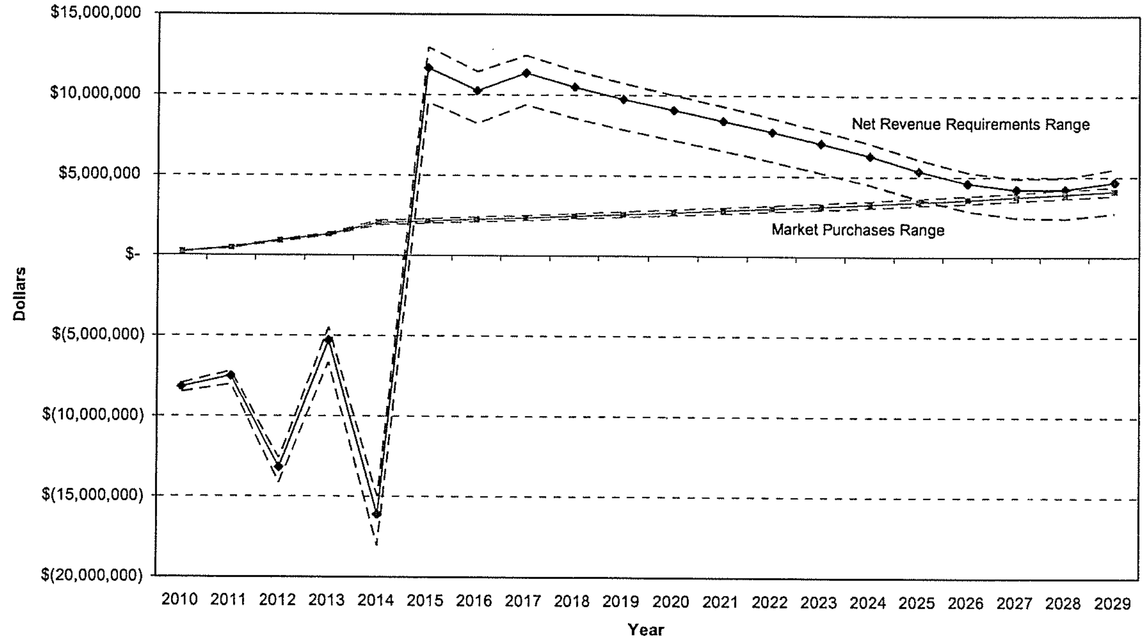
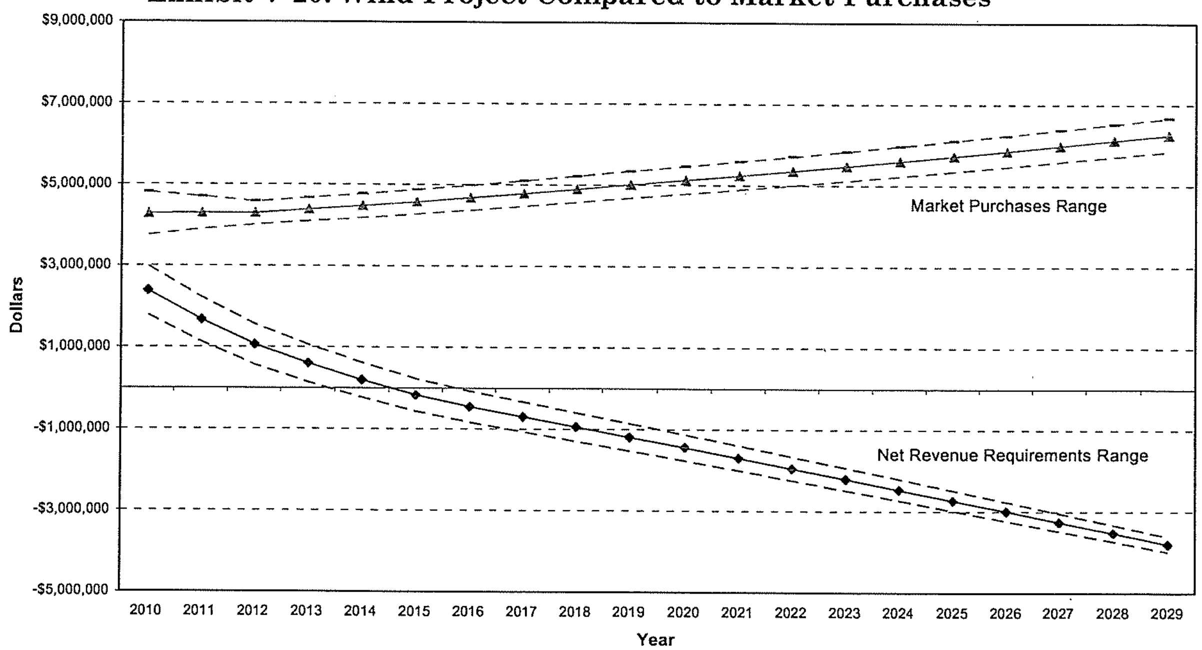


Exhibit V-20: Wind Project Compared to Market Purchases



VI. Assessment of Transmission Requirements

See Appendix H, "PSNH's Transmission Plan."

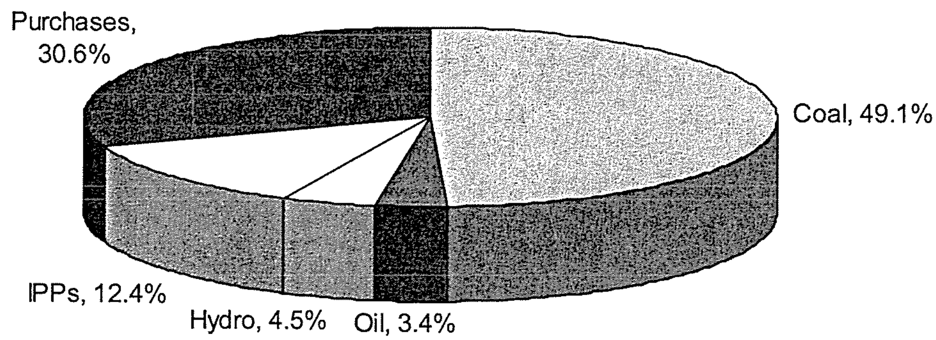
VII. Provision for Diversity of Supply Sources

This section discusses the diversity of PSNH's supply sources, its mandated purchased power policies, and PSNH's flexibility resulting from having a variety of fuel sources.

A. Supply Diversity and Flexibility

As discussed in the previous section, PSNH's supply resource mix includes a variety of fuel sources including coal, oil, hydroelectric, and biomass. In addition, Schiller units 4 and 6 are capable of burning coal or oil and Newington has dual oil and natural gas capability. The diverse supply portfolio allows PSNH to have flexibility in its generation strategy. Exhibit VII-1 demonstrates PSNH's diverse supply resource mix.

Exhibit VII-1: PSNH's Supply Resource Mix, 2006



PSNH must remain flexible in providing electric service to its energy service customers. Having physical generation facilities to serve part of PSNH's energy service load provides flexibility in managing and controlling the costs associated with the ever changing energy market. PSNH's new wood-fired boiler for Schiller unit 5 provides PSNH with greater fuel flexibility as well as providing assistance in meeting strict New Hampshire rules on air emissions. With an "open" system PSNH can readily implement delivery service for retail customers who choose a competitive supplier, yet PSNH is required to be prepared to provide electricity to customers who are not served by a competitive supplier.

B. Mandated Purchase Policies

PURPA requires PSNH to interconnect with and buy power from generators meeting the PURPA definition of Qualifying Facilities ("QFs"). These non-utility generators are either fueled by renewable sources or are a high efficiency cogenerator. PSNH must buy the generation from the projects at avoided cost rates as determined by the Commission. PURPA was enacted prior to electric restructuring when utilities, such as PSNH, planned for and supplied electric energy and capacity services as part of its integrated and exclusive services. The current obligation to purchase generation under PURPA is somewhat in conflict with the notion under restructuring that retail customers may choose a competitive supplier and that PSNH may eventually not have any load serving obligations. Virtually all of PSNH's required long-term purchases from QFs are well above the current market price of energy. A number of these contracts and rate orders expired at the end of 2006, which significantly lowered PSNH's stranded cost charge.

As the long-term contract and rate orders expire, PSNH will enter into new contracts with the QFs to supply energy at ISO-New England real time market prices, adjusted for administrative cost, wheeling cost and line losses.

VIII. Integration of Demand-Side and Supply-Side Options

This section analyzes the portfolio of supply side options in combination with demand side programs and identifies the combination of options that provide lower costs to customers and are achievable given the constraints of the current environment.

A. Overview

Under restructuring, PSNH must supply energy service to those customers who do not choose a competitive energy supplier. PSNH currently supplies between 60 and 70 percent of its customers' energy requirements using its own generation. PSNH therefore purchases the remaining 30 to 40 percent of its energy requirements from the wholesale market. In the absence of being enabled to build or buy new generation to meet customer demand, PSNH procures power on the open market using short-term purchase strategies. If customers were to choose a competitive retail electricity supplier, PSNH has the flexibility to adjust its purchases accordingly to serve energy service to its remaining customers.

PSNH does not have responsibility for long-term planning of generation. However, as a result of the settlement agreement approved by the Commission in Order No. 24,695 in Docket DE 04-072, PSNH has agreed to provide its views on meeting its customers' future energy and capacity requirements. The responsibility for long-term generation planning lies with the market. Merchant generators will construct new facilities presumably if the price signal is sufficiently high enough to ensure profitability. ISO-New England relies on the market to encourage developers to build new facilities to meet rising customer demand. The Forward Capacity Market is ISO-New England's latest attempt to create an incentive for new generation in New England.

Although PSNH does not engage in long-term generation planning for the construction of new units, it is still involved in transmission and distribution planning for the delivery of electricity. Transmission planning is under the jurisdiction of ISO-New England, but distribution planning is performed by PSNH. PSNH forecasts peak load for 12 areas for the purposes of capital project planning. Once it is determined that a capital improvement project is necessary for a particular area, PSNH begins planning the project. PSNH's C&LM program supplements its generation resources, but even with C&LM programs, PSNH is still required to purchase supplemental power from the wholesale market in order to meet energy service requirements, with the amount of purchases increasing as customer demand increases.

B. Demand Side Options

For purposes of this plan, PSNH analyzed increased energy efficiency programs funded through an increase in the System Benefits Charge. PSNH analyzed the following SBC funding levels to determine the impact that each option would have on delivery energy sales and peak demand:

- Increase SBC funding by 25 percent to 2.25 mills per kWh
- Increase SBC funding by 50 percent to 2.7 mills per kWh
- Increase SBC funding by 67 percent to 3 mills per kWh

The potential impact of each of these options is demonstrated below in Exhibits VIII-1 and VIII-2.

Exhibit VIII-1: CORE Programs Impact on Delivery Energy Sales at Various SBC Levels with Increases Beginning in 2009

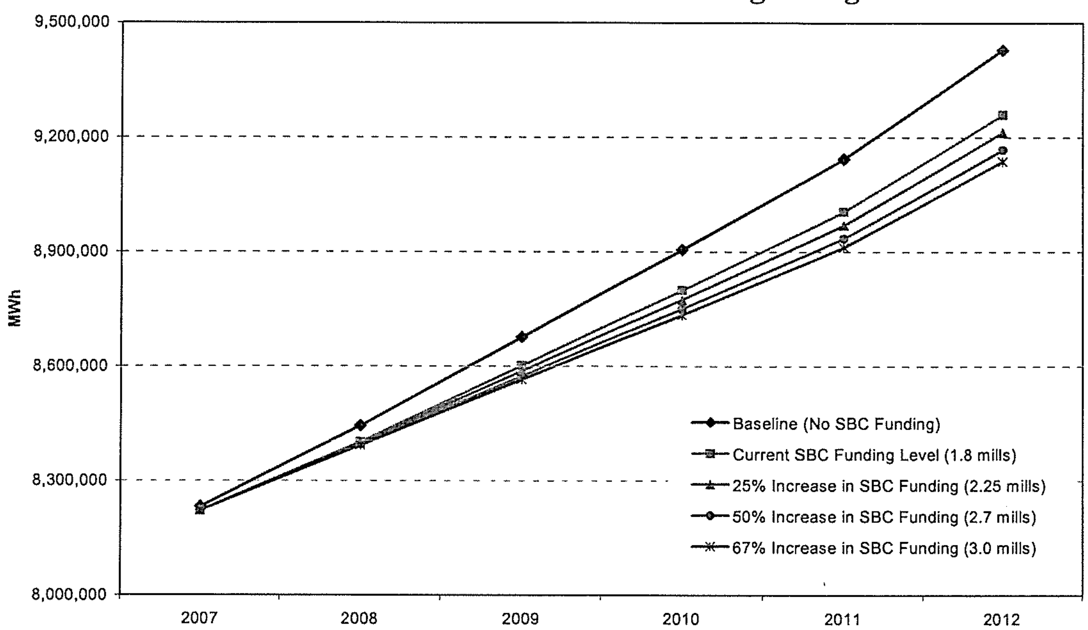
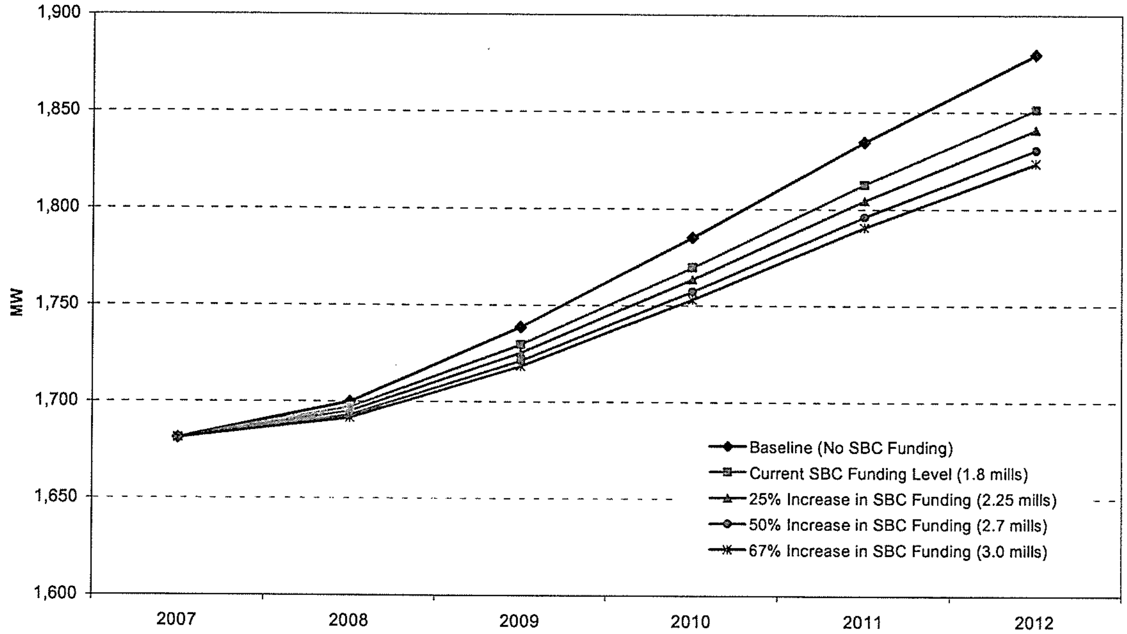


Exhibit VIII-2: CORE Programs Impact on Peak Demand at Various SBC Levels with Increases Beginning in 2009



C. Supply Side Options

PSNH also analyzed a series of options that it feels would provide rate stability to customers' rates, fuel diversity, Renewable Portfolio Standard compliance, environmental and economic benefits, and enhance the reliability of New England's electricity supply. As mentioned in section V.B.8, PSNH analyzed the following supply side options to meet the energy and capacity resource gap:

- 50 MW biomass plant
- 20 MW peaking units
- 3-12 MW solar photovoltaics
- 24 MW wind project

D. Integrated Portfolio Approach

As a result of the analysis, PSNH selected a balanced portfolio which includes energy efficiency and demand-side management programs, baseload, and peaking generation options, and long-term market purchase contracts. Appendix G describes the avoided cost methodology and forecast used in the analysis as well as the approach used to analyze the supply side options for inclusion in the potential portfolio. As a result of the analysis, PSNH identified a portfolio of options to meet customers' energy and capacity requirements and help to meet New Hampshire RPS requirements. The portfolio includes:

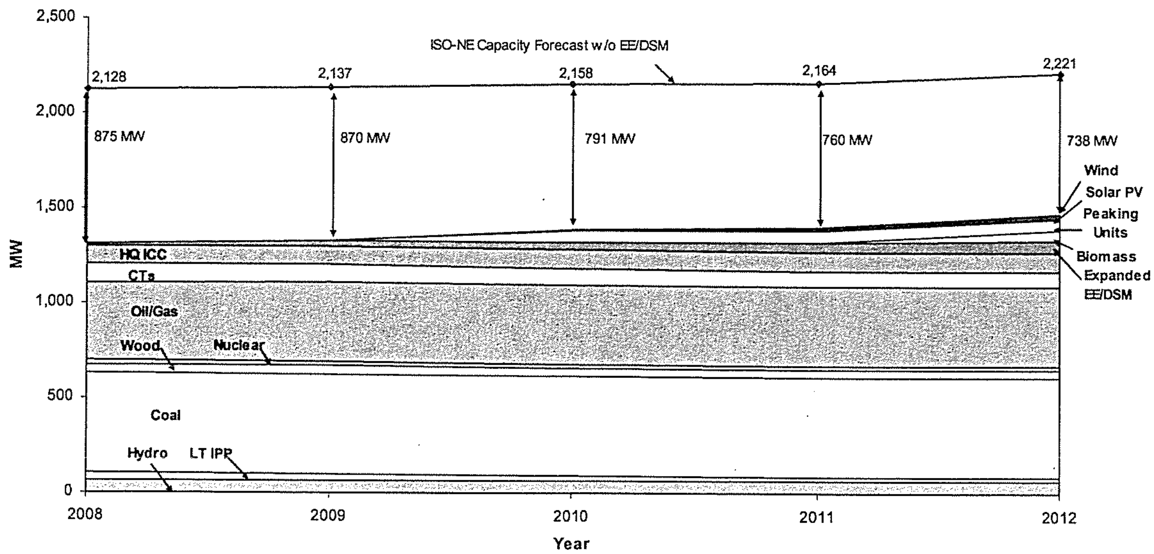
- 26 MW of additional CORE programs funded by a 50 percent increase in the SBC
- One 50 MW biomass plant
- Three 20 MW peaking units totaling 60 MW

- Solar photovoltaic installations totaling up to 12 MW
- Six 24 MW wind projects totaling 144 MW

The chart and table in Exhibit VIII-3 show the addition of this portfolio to PSNH's current assets. Using this portfolio, by the end of the planning period, 168 MW could be added to PSNH's portfolio, decreasing the capacity deficiency from 900 MW to 700 MW. However, this shows that PSNH would still need to purchase about 30 percent of its needs from the market.

Without the addition of this portfolio, PSNH will pay over $300 million in the capacity market over the planning period. With this portfolio, PSNH's capacity payment would be reduced to $270 million over the planning period with continued savings beyond that time.

Exhibit VIII-3: Capacity Resource Portfolio



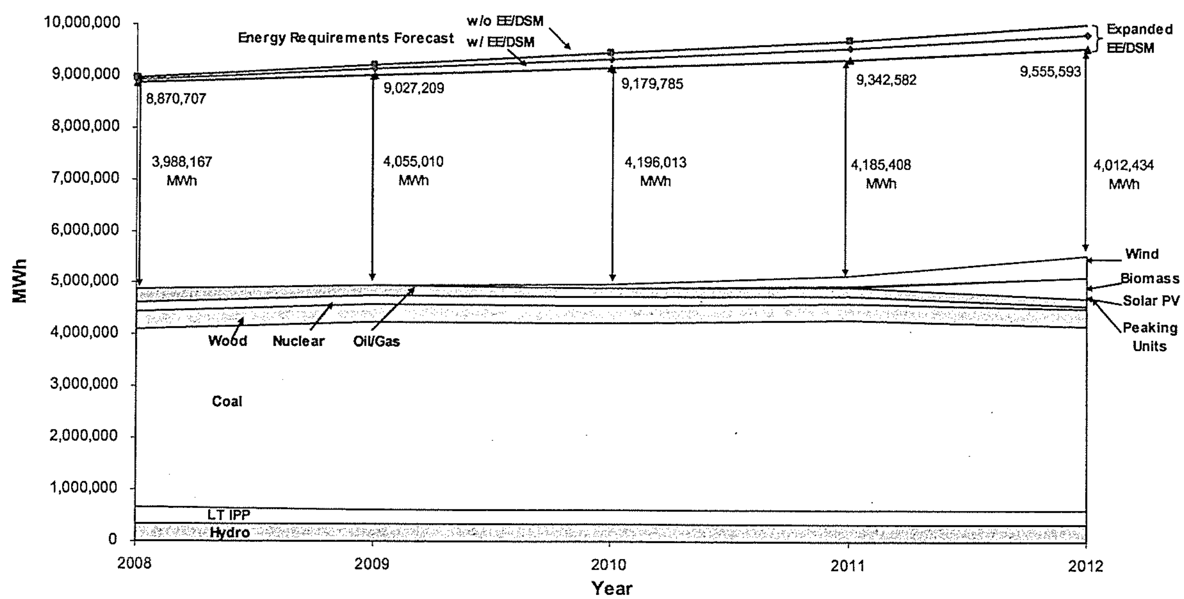
	2008	2009	2010	2011	2012
Capacity Requirement (MW)	2,128	2,137	2,158	2,164	2,221
Existing Resources (MW):					
Hydro	67	67	66	65	65
LT IPP	36	31	25	21	21
Coal	531	531	529	528	528
Wood	42	42	41	40	40
Nuclear	21	21	21	21	21
Oil/Gas	413	419	419	419	419
CTs	95	95	88	82	82
Hydro Quebec ICC	97	97	97	97	97
Existing CORE Programs	10	18	26	34	42
Total*	**1,248**	**1,257**	**1,286**	**1,307**	**1,315**
New Demand Side Resources (MW):					
Increased CORE Programs	5	10	15	21	26
New Supply Side Resources (MW):					
Biomass	0	0	0	0	50
Peaking Units	0	0	60	60	60
Solar Photovoltaic**	0	0	1	2	5
Wind Project**	0	0	5	14	27
Total New Resources	0	0	66	76	142

Capacity Deficiency	875	870	791	760	738

*Includes an adjustment for EFORd (Demand Equivalent Forced Outage Rate)
**Solar PV capacity is derated to 40% and wind capacity is derated to 19%

In addition to the capacity payment, PSNH would be required to purchase energy to meet its customers' requirements. PSNH will pay $1.3 to $1.6 billion in the energy market over the planning period. Exhibit VIII-4 shows the additional energy that PSNH would gain from this portfolio. With this portfolio of assets, PSNH's energy payment would be reduced to about $1.0 to $1.2 billion over the planning period with additional savings thereafter.

Exhibit VIII-4: Energy Resource Portfolio



	2008	2009	2010	2011	2012
Energy Requirement (MWh)	**8,968,207**	**9,215,137**	**9,458,141**	**9,711,366**	**10,014,805**
Existing Demand Side Resources (MWh):					
Existing CORE Programs	(45,060)	(79,057)	(113,053)	(147,050)	(181,047)
Existing Supply Side Resources (MWh):					
Hydro	334,721	334,721	334,721	334,721	334,721
LT IPP	326,375	283,676	283,676	283,676	283,395
Coal	3,453,980	3,635,964	3,614,114	3,674,134	3,573,770
Wood	335,340	332,433	332,433	318,829	333,344
Nuclear	168,366	178,695	168,414	168,398	40,118
Oil	263,759	206,710	176,854	165,617	163,296
Total	**4,882,541**	**4,972,199**	**4,910,212**	**4,945,375**	**4,728,644**
New Demand Side Resources (MWh):					
Increased CORE Programs	(7,380)	(29,815)	(52,249)	(74,684)	(97,119)
New Supply Side Resources (MWh):					
Biomass Plant	0	0	0	0	394,200
Peaking Units	0	0	2,764	2,764	2,764
Solar Photovoltaic	0	0	3,520	7,205	13,889
Wind Project	0	0	67,277	201,830	403,661
Total New Supply Resources	**0**	**0**	**76,935**	**215,173**	**817,888**
Energy Deficiency	**3,988,167**	**4,055,010**	**4,196,013**	**4,185,408**	**4,012,434**

D.1. Energy Efficiency and Demand Side Management Programs

PSNH proposes to expand implementation of its CORE Energy Efficiency programs funded through a 50 percent increase in the System Benefits Charge. PSNH estimates the expanded programs would reduce the 2012 peak demand by 26 MW[18] and reduce energy usage by 261,000 MWh over the 2008-2012 planning period at an annual cost of $7.4 million. This proposal is based on an assessment and balancing of a number of considerations including:

- The ability to ramp up the existing programs
- The potential for the installation of additional efficiency measures in PSNH's service territory
- The rate impact on customers
- Cost-effectiveness of the programs

PSNH is not proposing any additional demand-side management programs at this time. As discussed in Section IV.C, PSNH analyzed a number of demand-side programs; however, none are cost-effective and/or feasible at this time. PSNH will continue to monitor this situation and is prepared to consider implementation of cost-effective programs that would be beneficial for our customers

D.2. Biomass Plant

A 50 MW biomass plant was modeled as a baseload resource with a 90 percent capacity factor to provide low cost energy and capacity to meet the Class I New Hampshire RPS requirements, provide additional diversification to PSNH's supply base and supports enhanced rate stability. In addition, the renewable fuel source avoids added environmental compliance costs.

D.3. Distribution Level Peaking Units

Three 18.6 MW distribution level peaking unit plants were modeled to meet PSNH's needs. These peaking units would have a low capacity factor and would help to promote price stability due to the fact that they would operate during high price times and would be less expensive than expected ISO-New England FCM prices. In addition, the peaking units enhance reliability on PSNH's distribution system.

D.4. Solar Photovoltaic

Solar photovoltaic installations were modeled to meet the New Hampshire RPS requirement and provide PSNH with an intermittent source of energy and capacity. Installations of up to 12 MW could be installed over the planning horizon. Currently, non-utility companies can apply for a Business Energy Tax Credit ("BETC") to offset the costs of

[18] The capacity reduction figure is obtained by grossing up the program reductions for losses (8%) and reserves (14.3%). This is the same process used by ISO- New England to determine capacity reductions.

solar photovoltaic installations. This tax credit is due to expire at the end of 2008, but there is a proposal in the United States House to extend the BETC for 8 years and to remove the restriction for utilities. PSNH will keep a close watch on the current proposal to extend the BETC. In the event that this proposal succeeds, solar photovoltaics may be an economic solution and will help to satisfy PSNH's Class II New Hampshire RPS requirement, diversify its supply sources further, and provide a benefit to customers.

D.5. Wind

PSNH modeled a 24 MW wind project to add an additional renewable fuel source to the portfolio. This is equivalent to twelve 2 MW wind turbines. Due to the low capacity factor of a wind turbine, around 30 percent, PSNH included up to six 24 MW wind projects in the portfolio, ramped up over the planning period, which is roughly equivalent to the energy output of a 50 MW biomass plant. A wind project would require interconnection to the PSNH's distribution system and once connected would potentially support the Class I requirements of the New Hampshire RPS and PSNH's desire to add more and new sources of renewable energy to PSNH's generation mix, addition of wind power projects also helps with reducing air emissions and enhancing fuel diversity.

D.6. Long-Term Contracts

PSNH will strive to meet the remaining resource balance with a mix of long-term and short-term contracts. PSNH currently uses a combination of one-year contracts and short-term market purchases. PSNH will continue to explore opportunities for contracts with durations greater than one year.

IX. Assessment of Plan Integration and Impact on State Compliance with the Clean Air Act Amendments of 1990

This section assesses PSNH's compliance with the Clean Air Act Amendments of 1990 and describes the strategies PSNH employs to reduce emissions in accordance with federal and state regulations and regional policies.

A. Overview

PSNH has implemented an integrated approach to emissions management and fuel supply planning. An integrated approach is necessary due to the interdependent nature of the two activities.

Federal and state environmental regulations essentially determine what fuels may be burned by PSNH's fossil-fuel fired generation fleet – Merrimack, Schiller and Newington Stations. In order to comply with increasingly more stringent regulations, PSNH has been very proactive and progressive in reducing and managing emissions. The flexibility provided under market-based incentive programs, including the recently enacted New Hampshire Clean Power Act (RSA Chapter 125-O), allows PSNH to implement the most cost-effective measures to meet its emission reduction requirements.

Close management of PSNH's emissions allocations and allowance transactions, fuel switching and capital additions, while maintaining a diverse fuel mix, enables PSNH to operate the fleet in the most cost effective manner. Recognizing the upward pressure on electricity costs caused by more stringent regulation and higher compliance costs, this approach is critical and provides the most benefit to PSNH's customers and shareholders.

B. Emissions Policies at the Federal Level

Under existing state and federal regulations, several pollutants emitted by PSNH's electric generating stations are currently regulated, monitored and controlled.

The federal Clean Air Act Amendments of 1990 ("CAAA") established challenging goals for the electric power industry. Compliance with lower SO_2 emission levels, to be met in a two-phase stepped approach under a national cap and trade program, was mandated under Title IV. NOx emission reductions requirements were imposed under Title IV and Title I, while Title III required a study of hazardous air pollutants, including mercury, from electric utilities. The CAAA also contained the framework for the future control of particulate emissions.

Title IV of the CAAA set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase tightening of the restrictions placed on fossil fuel-fired power plants.

Phase I began in 1995 and affected 263 units at 110 of the mostly coal-burning electric utility plants located in 21 eastern and Midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Emissions data indicate that 1995 SO_2 emissions at these units nationwide were reduced by almost 40 percent below their required level.

Phase II, which began in 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing over 2,000 units in all.

Title IV also called for a two-part strategy to reduce NOx emissions from coal-fired electric power plants by 2 million tons by the year 2000, by over 400,000 tons per year between 1996 and 1999 and by approximately 1.17 million tons per year beginning in the year 2000.

In addition to the Title IV requirements, NOx emissions reduction requirements were also mandated under Title I of the Act. Beginning in 1995 with the implementation of NOx Reasonably Available Control Technology ("RACT") Programs, NOx emission standards were imposed requiring the installation of emissions control technology at generating stations throughout the Northeast. Beginning in 1999, ozone season NOx emissions were regulated through the implementation of NOx Budget Programs in twelve states throughout the Northeast, including New Hampshire. By 2004, through the implementation of the NOx State Implementation Plan ("SIP") Call, NOx Budget Programs were required in 20 states throughout the eastern and Midwestern United States (excluding New Hampshire, Maine and Vermont).

Under Title III of the CAAA, 189 hazardous air pollutants ("HAPs"), including mercury (Hg), are regulated. Title III requirements include reductions of HAPs through the implementation of a Maximum Achievable Control Technology ("MACT") standard. MACT is a control technology driven emission standard based on the maximum control achievable in a particular industry.

On March 15, 2005, the Environmental Protection Agency ("EPA") published a rule that modified its so-called "Regulatory Determination" that regulation of HAP emissions from Electric Utility Steam Generating Units ("EUSGU") was "appropriate and necessary." On the same day, EPA finalized the "Clean Air Mercury Rule" ("CAMR") that controls mercury emissions through a cap and trade program. The states have the option to participate in the cap and trade program. Each participant state may allocate its allowance budget to the affected facilities within the state, as it sees fit. For non-participant states, the allowance budget becomes a fixed, enforceable emission limit for the state. The states may adopt more stringent controls on EUSGUs or regulate other source categories if they wish.

In addition to future regulations being implemented under the CAAA, several multi-pollutant bills regulating emissions from fossil-fuel fired electric utility generators have been introduced in Congress. Currently there are several bills being considered, all of which propose to regulate NOx, SO_2, and mercury under a national cap and trade program beginning in 2008. Two of the bills also include CO_2.

C. State and Regional Activities

Prior to the passage of the CAAA, the State of New Hampshire implemented the Acid Rain Control Act (RSA Chapter 125-D) imposing an annual SO_2 cap of 55,150 tons from the combined output of PSNH's large electric generators. Although PSNH measures and monitors SO_2 emissions from individual units, SO_2 emissions are managed and controlled on a system-wide basis by utilizing a spectrum of fuel types and qualities.

In addition to the CAAA requirements, the State of New Hampshire enacted the New Hampshire Clean Power Act (RSA Chapter 125-O) in 2002 which established a market-based economic incentive program regulating emissions of SO_2, NOx, mercury, and CO_2, began January 2007. This program is in addition to the existing state and federal SO_2 and NOx emissions programs. In 2006, legislation updating RSA Chapter 125-O specific to mercury emissions reduction requirements was passed.

Simply stated, the New Hampshire Clean Power Act establishes an output-based allocation program which allows PSNH to either implement on-site emissions reductions or purchase allowances to comply. As stated in RSA Chapter 125-O:1, VI, "...the environmental benefits of air pollutant reductions can be most cost-effectively achieved if implemented in a fashion that allows for regulatory and compliance flexibility under a strictly limited overall emissions cap. Specifically, market-based approaches, such as trading and banking of emission reductions within a cap-and-trade system, allow sources to choose the most cost-effective ways to comply with established emission reduction requirements. This approach also provides sources with an incentive to reduce air pollutant emissions sooner and by greater amounts, promotes the development and use of innovative new emission control technologies, and specifies to the greatest extent possible performance results regarding environmental improvement rather than dictating expensive, facility-specific, command-and-control regulatory requirements."

The requirements enacted under RSA Chapter 125-O, and the implementing administrative rules, Env-A 2900 apply to PSNH's existing fossil fuel burning steam electric power plant units, namely Merrimack Units 1 and 2, Schiller Units 4, 5, and 6, and Newington Unit 1, excluding any units that are repowered.

Pursuant to RSA Chapter 125-O: 3 and Env-A 2905, PSNH will receive annual allocations, based on the output of each unit, of 7,289 tons of SO_2, 3,644 tons of NOx, and 5,425,866 tons of CO_2. The annual emission cap for mercury will be determined at the completion of mercury baseline coal testing undertaken during 2006 and 2007.

Under RSA Chapter 125-O and Env-A 2900, PSNH is required to reduce emissions to comply with the annual emissions caps implemented and/or purchase allowances to offset any emissions in excess of the annual allocations. PSNH's compliance plan, filed with the New Hampshire Department of Environmental Services in July 2003, describes the technologies, operational modifications, market-based approaches, or other methods that will be used to comply with the emission caps in the most cost effective manner.

D. PSNH's Initiatives and Emissions Policy Conclusions

PSNH will continue to comply with the regulations outlined above through proactive, cost effective mechanisms including fuel switching, emissions allowance management (sale, procurement, and/or use), emission rate optimization, close monitoring, and measurement of emissions. Emission allowance management comprises the assessment of PSNH-specific requirements versus state and federal allocations and allowance inventory levels. Generally, SO_2 and NOx emission allowances are market-traded fungible commodities that are available for purchase and sale (in a transparent market) as market participants balance their respective supply and demand requirements over a period of time. Annual system requirements are estimated on a pro forma basis using anticipated generating unit capacity factors, emission rates, and potential fuel type availability and pricing information. Balancing fuel qualities, emission allowances, and capacity factors to meet the regulatory requirements is the crux of this overall effort.

A subgroup of PSNH's Generation management team meets at least annually to comprehensively analyze PSNH's position and to set strategic direction for PSNH Generation. Also an additional eight to ten meetings throughout the year, an emissions management team formally discusses the system's emissions status, makes pro forma assessments (with sensitivity analyses) and makes tactical decisions to achieve its goal of complying with the emission regulations in a cost-effective manner. Various short-term methods employed to change emission levels include switching to higher or lower sulfur fuels; either high sulfur coal to low sulfur coal or high sulfur residual oil (up to 2 percent sulfur) to lower sulfur oil and/or natural gas consumption. This group analyzes year-to-date data and implements the necessary changes in order to comply on a real-time basis.

X. Compliance with the New Hampshire Renewable Portfolio Standard

This section assesses PSNH's compliance with the recently developed New Hampshire Electric Renewable Portfolio Standard and describes the strategies PSNH employs to comply with the RPS.

A. Background

Four New England states–Connecticut, Maine, Massachusetts, and Rhode Island–have established Renewable Portfolio Standards to encourage the development of renewable resources in the region. Vermont currently has voluntary renewable portfolio goals, which if not achieved by 2012 will become a mandatory RPS in 2013. Additionally, a number of other Northeastern states, including New Hampshire, have implemented renewable portfolio standards.

New Hampshire's RPS requires electricity providers to acquire RECs equivalent to 23.8 percent of retail electricity sold to end-use customers by 2025. Of the 23.8 percent target, 16.3 percent is to be derived from sources installed after January 1, 2006, whereas the remainder is to be derived from existing resources. House Bill 873 created a new RSA Chapter 362-F titled *"ELECTRIC RENEWABLE PORTFOLIO STANDARD."*

House Bill 873 describes the purpose of the Renewable Portfolio Standard as follows:

> "Renewable energy generation technologies can provide fuel diversity to the state and New England generation supply through use of local renewable fuels and resources that serve to displace and thereby lower regional dependence on fossil fuels. This has the potential to lower and stabilize future energy costs by reducing exposure to rising and volatile fossil fuel prices. The use of renewable energy technologies and fuels can also help to keep energy and investment dollars in the state to benefit our own economy. In addition, employing low emission forms of such technologies can reduce the amount of greenhouse gases, nitrogen oxides, and particulate matter emissions transported into New Hampshire and also generated in the state, thereby improving air quality and public health, and mitigating against the risks of climate change. It is therefore in the public interest to stimulate investment in low emission renewable energy generation technologies in New England and, in particular, New Hampshire, whether at new or existing facilities."[19]

The RPS separates the portfolio standards required for energy resources into four classes: "Class I," "Class II," "Class III," or "Class IV." The definitions of each of the four classes are described below.

[19] HB 0873 - http://www.gencourt.state.nh.us/legislation/2007/HB0873.html

- **Class I** - New Renewable Energy: electricity from any of the following, provided the source began operation after January 1, 2006:
  - Wind energy
  - Geothermal energy
  - Hydrogen derived from biomass fuels, biogas, or landfill gas
  - Ocean thermal, wave, current, or tidal energy
  - Biogas or landfill gas
  - Eligible biomass technologies meeting air emissions requirements
  - Solar electric not used to meet Class II, or customer-sited solar water heating that displaces electricity
  - The incremental new production of electricity in any year from an eligible biomass, eligible methane source, or hydroelectric generating facility of any capacity, over its historical generation baseline
  - The production of electricity from Class III or IV sources that have been upgraded or repowered through significant capital investment.

- **Class II** - New Solar: electricity from solar technologies provided the source began operation after January 1, 2006.

- **Class III** - Existing Biomass/Methane: electricity from eligible biomass technologies having a gross nameplate capacity of 25 MW or less, and methane gas. The source must have begun operation prior to January 1, 2006:

- **Class IV** - Existing Small Hydroelectric: electricity from hydroelectric energy provided the source began operation prior to January 1, 2006, has a gross nameplate capacity of 5 MW or less, and meets other environmental protection criteria.

Electric providers must meet the standard according to the following compliance schedule. Exhibit X-1 shows the compliance requirements by class on a percentage basis and a total megawatt hour basis.

Exhibit X-1: RPS Compliance

(%)	2008	2009	2010	2011	2012	2013	2014	2015	2025
Class I	0.00%	0.50%	1.00%	2.00%	3.00%	4.00%	5.00%	6.00%	16.00%*
Class II	0.00%	0.00%	0.04%	0.08%	0.15%	0.20%	0.30%	0.30%	0.30%
Class III	3.50%	4.50%	5.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Class IV	0.50%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%

*Class I increases an additional one percent per year from 2015 through 2025. Classes II-IV remain at the same percentages from 2015 through 2025. (Provisions for exceptions and delays are described below.)

(MWh)	2008	2009	2010	2011	2012	2013	2014	2015	2025
Class I	0	43,013	87,995	180,118	277,789	377,509	483,488	594,372	2,013,174
Class II	0	0	3,520	7,205	13,889	18,875	29,009	29,719	37,747
Class III	294,079	387,119	483,971	585,384	601,875	613,451	628,534	643,903	817,852
Class IV	42,011	86,026	87,995	90,059	92,596	94,377	96,698	99,062	125,823

B. Rules for Compliance

In order to comply with the new RPS, the NHPUC will establish a REC program utilizing the regional generation information system ("GIS") of energy certificates administered by ISO-New England and the New England Power Pool ("NEPOOL"). RECs from customer-sited sources are assigned to the system owner and behind-the-meter generation located in New Hampshire is eligible to participate in the RPS. Unused RECs from the prior two years, or RECs from the first quarter of a subsequent year, can be used to meet up to 30 percent of a given year's compliance targets. Distribution companies may request to enter into multi-year contracts for RECs or electricity bundled with RECs to meet the RPS. Rural electric cooperatives may enter into multi-year contracts without approval from the Commission.

To be eligible for RPS compliance, renewable energy sources must be within the New England control area unless the source is located in a control area adjacent to the New England control area and the energy produced by the source is actually delivered into the New England control area for consumption by New England customers.

Compliance reports must be filed with the Commission by July 1st of each year from each electricity provider. In lieu of meeting the portfolio requirements, an electricity provider may make payments to a new renewable energy fund established by this law to support renewable energy initiatives. Class II moneys will only be used to support solar energy technologies in New Hampshire.

Default service providers are authorized to recover prudently incurred costs of the RPS from retail customers. The NHPUC is authorized to fine suppliers that violate RPS requirements, revoke their registration, or prevent them from doing business in the state.

The Commission may accelerate or delay by up to one year, any given year's increase in class I or II RPS requirement for good cause, and after notice and hearing. In addition, after notice and hearing, the Commission may modify the Class III and IV requirements for calendar years beginning January 1, 2012 such that the requirements are equal to an amount between 85 percent and 95 percent of the reasonably expected potential annual output of available eligible sources after taking into account demand from similar programs in other states.

The Commission must conduct a review of the RPS program and report its findings to the legislature by November 1, 2011, 2018, and 2025, including any recommendations for changes to the class requirements or other aspects of the electric renewable portfolio standard program. In addition, the Office of Energy and Planning in consultation with the Energy Planning Advisory Board is directed to study, evaluate, and make recommendations including potential legislation related to a thermal renewable portfolio standard and other incentives or mechanisms to promote thermal renewable energy use.[20]

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[20] Database of State Incentives for Renewables and Efficiency (DSIRE) - http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NH09R&state=NH&CurrentPageID=1&RE=1&EE=1

C. Cost of Compliance

If the RPS requirement can not be met through ownership of qualified renewable generation sources or the purchase of Renewable Energy Certificates from a qualified renewable generation source, the provider has the option to pay the Alternative Compliance Payments ("ACP") to the State of New Hampshire. The 2008 ACP rates for each MWh not met for a given class obligation through the acquisition of certificates are $57.12 for Class I, $150 for Class II, and $28 for Classes III and IV. Beginning in 2008, the Commission will adjust these rates by January 31st of each year using the Consumer Price Index ("CPI").

If PSNH were to fulfill its RPS requirements solely through Alternative Compliance Payments, the cost to PSNH's customers would be about $1.7 billion cumulatively between 2008 and 2025. Exhibit X-2 demonstrates the annual RPS compliance costs using the ACP. The CPI was assumed to be about 2.2 percent for this illustrative analysis. This analysis is an appropriate benchmark to use to assess the cost of compliance for PSNH since the purchase price of RECs from the marketplace is expected to approach the cost to customers from ACPs.

Exhibit X-2: Annual RPS Compliance Costs

($000s)	2008	2009	2010	2011	2012	2013	2014	2015	2025
Class I	$0	$2,508	$5,243	$10,973	$17,321	$24,090	$31,569	$39,702	$167,736
Class II	$0	$0	$5,507	$11,526	$2,274	$3,163	$4,974	$5,213	$8,259
Class III	$8,234	$11,066	$14,136	$17,482	$18,396	$19,189	$20,118	$21,084	$33,403
Class IV	$1,176	$2,459	$2,570	$2,689	$2,830	$2,952	$3,095	$3,244	$5,139
Total	$9,411	$16,033	$27,456	$42,670	$40,822	$49,395	$59,756	$69,242	$214,538

D. PSNH's Renewable Strategy

PSNH is focused on long-term renewable resources. Currently, the renewable power included in PSNH's resource supply mix includes hydroelectric, wood, and wind resources. PSNH was able to successfully expand its portfolio by constructing a wood-fired boiler at Schiller Station. Additionally, PSNH has refurbished its Smith Hydro plant to provide a greater amount of renewable energy and is working with developers on wind projects in New Hampshire.

PSNH sees significant value in investing in additional renewable power as part of its energy portfolio. The portfolio in section VIII demonstrates PSNH's desire to meet customers' resource needs with a combination of energy efficiency and renewable generation. Specifically, 50 megawatts of biomass generation and between 50 and 100 megawatts of other renewable generation would not only provide a lower cost option of complying with New Hampshire's RPS, but also provide additional generation for PSNH, thus reducing the amount of market purchases currently required.

PSNH continues to aggressively manage its generating assets to provide low-cost transition/default energy service to customers. With a large number of above market IPP contracts expiring in the next couple of years, and a vibrant REC market developing in New England, PSNH sees renewable power as a viable strategy to help keep energy prices stable.

PSNH will continue to monitor the rulemaking process associated with implementation of the New Hampshire RPS standard to determine the means by which lowest cost compliance can be achieved.

For Class 1, Northern Wood Power will be qualified as a REC-eligible asset in New Hampshire. Details will need to be worked out to determine appropriate valuing of RECs from NWP for compliance with the financial obligations established in the NWP settlement agreement approved by the Commission prior to the modification of the unit. Pending this resolution, NWP RECs may be used to fulfill PSNH's RPS requirements, or may need to be sold off-system to assure appropriate crediting of value in satisfaction of the settlement agreement terms. In addition, the additional output as a result of the Smith Hydro refurbishment should also qualify for Class I RECs.

For Class 2, the analysis contained herein shows that construction and ownership of Solar PV generating equipment can be economic for customers, with passage of proposed federal legislation that would extend the Business Enterprise Tax Credit to electric utility companies for Solar PV installations. Absent the BETC, it is unlikely that a significant amount of Solar PV will be constructed in New England, making it difficult to meet the Solar PV RPS requirements through the purchase of RECs. Pending the outcome of the RPS rulemaking process, PSNH will evaluate the benefits of making Alternative Compliance Payments and helping to develop a Solar PV fund, which can be used to promote future development of Solar PV in New Hampshire to help meet RPS requirements.

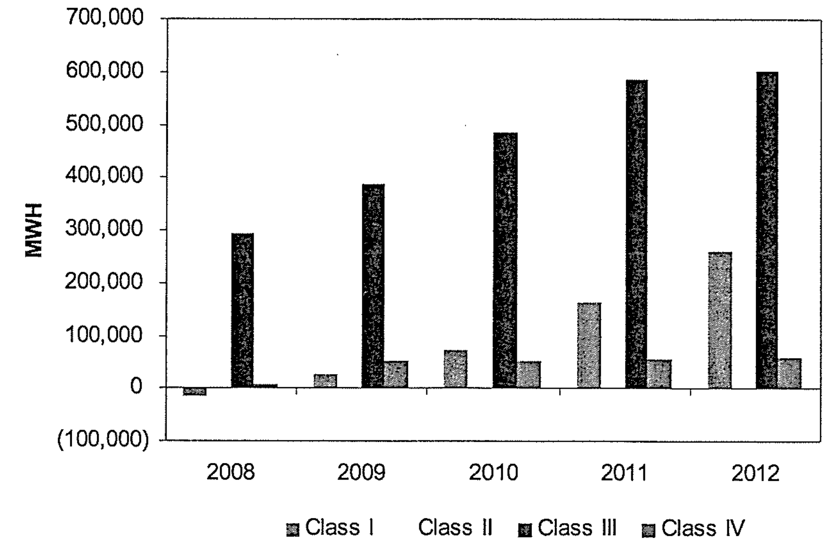
For Class 3, PSNH will seek to establish intermediate term contracts (1 to 3 years) with facilities that qualify to provide Class 3 RECs. It should be noted that PSNH believes that many of these facilities, and in particular the existing biomass facilities, if qualified to provide Class 3 RECs in New Hampshire, will also have the opportunity to provide Class 1 RECs in Connecticut. The market price differential between Class 1 Connecticut RECs and Class 3 New Hampshire RECs and other factors will dictate the availability of Class 3 RECs for purchase by PSNH to meets its Class 3 RPS obligation.

For Class 4, PSNH expects that many of its existing hydroelectric facilities will qualify as REC eligible when RPS rules are finalized. PSNH will qualify those facilities and supply RECs produced at those units to fulfill its obligation under the RPS.

Final outcome of the RPS rules now under consideration by the Commission will impact the strategic decisions made to provide lowest cost RPS compliance over the life of the RPS standard. It may be appropriate to make Alternative Compliance Payments in the short term to fund programs or projects longer term that will ultimately best serve the objective of increasing renewable power supply in New Hampshire and in the region.

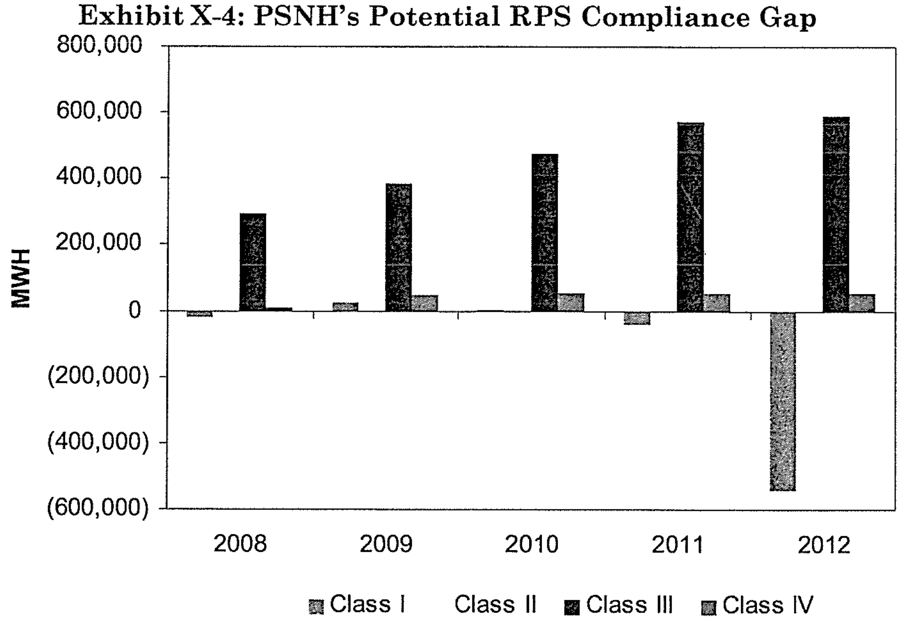
Beginning in 2008, PSNH-owned generating resources will produce about 51,000 MWh that could potentially qualify for Classes I and IV. The runner upgrade at Smith Hydro is expected to generate an additional 16,679 MWh per year that could qualify for Class I and about 34,000 MWh from PSNH's existing small hydros could potentially qualify for Class IV. Exhibit X-3 demonstrates PSNH's current RPS compliance gap.

Exhibit X-3: PSNH's Current RPS Compliance Gap



If PSNH were to implement the demand side and supply side initiatives outlined in previous sections, PSNH's RPS compliance gap would be reduced. Increased energy efficiency and demand side management programs would reduce the energy requirement, an additional biomass plant and new wind turbines would exceed the Class I RPS requirement initially through the planning period, and new solar PV installations would help to meet the Class II requirement. Exhibit X- 4 demonstrates PSNH's RPS compliance gap after accounting for the additional resources identified in PSNH's potential portfolio.

Exhibit X-4: PSNH's Potential RPS Compliance Gap



XI. Compliance with the National Energy Policy Act of 1992

RSA 378:38, VIII requires that the Company's Least Cost Plan include a discussion of compliance with the National Energy Policy Act of 1992 ("EPAct"). This section describes PSNH's compliance with the sections of the EPAct pertaining to integrated resource planning for electric utilities.

A. Energy Policy Act of 1992

PURPA required state public utilities commissions to consider certain standards for ratemaking including cost of service, declining block rates, interruptible and time of day rates. (16 USC §2621(d)). Although the state commissions were required to consider the federal standards outlined in PURPA, they were not bound to implement them. (16 USC §2621(c)). The Energy Policy Act of 1992 added certain provisions to the PURPA standards which relate directly to integrated resource planning.

> "Energy Policy Act of 1992, Subtitle B – Utilities – Amends the Public Utility Regulatory Policies Act of 1978 (PURPA) (1) to mandate that: each electric utility employ integrated resource planning; (2) the rates for a State regulated electric utility are such that its outlay for demand side management measures (including energy conservation and energy efficiency resources), are at least as profitable as those for the construction of new generation, transmission, and distribution equipment; (3) the rates charged by an electric utility are such that it is encouraged to make outlays for all cost-effective improvements in energy efficient power generation, transmission and distribution; and (4) such rates and charges are implemented in a manner that assures that utilities are not granted unfair competitive advantages over small businesses engaged in the transactions regarding demand side energy management measures." Public Law No. 102-486, Summary as of 10/5/1992 Conference Report filed in the House.

The following sections describe PSNH's compliance with each of the four requirements listed above.

A.1. Requirement to Perform Integrated Resource Planning

The EPAct requires that integrated resource plans must be updated on a regular basis, provide for public participation, and the plans must be implemented. 16 USC 2601(d)(7). RSA 378:38 requires electric utilities to file a least cost integrated resource plan biennially. The Commission typically opens an adjudicatory proceeding with the opportunity for intervention and full participation by members of the public.

A.2. Rates for Demand Side Investment Commensurate with those for Generation, Transmission and Distribution

Under the EPAct, "The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment." 16 USC 2601(d)(8)

Under the Core Energy Efficiency programs, PSNH and other utilities are allowed to earn an incentive based upon meeting a cost effectiveness test and a pre-determined level of kilowatt-hour savings. If the utilities meet this two pronged test, they can recover up to 12 percent of the program expenditures. PSNH has earned an incentive in previous years.

Prior to restructuring, when PSNH recovered the costs of conservation and load management expenditures through base rates, it was allowed to recover lost fixed costs revenues. This recovery method attempted to compensate PSNH for installing energy efficiency measures which reduced the sales and corresponding revenues PSNH would have recovered had the energy efficiency measures not been installed. This recovery mechanism lost favor as the amount of lost fixed cost revenues became quite large as a percentage of the total program expenditures in between general rate cases. The Energy Efficiency Working Group developed the Shareholder Incentive, which is in place today, as an alternative to lost fixed cost revenues.

PSNH recovers its investment in generation, transmission and distribution through rates by collecting a depreciation rate for its investment (a return of the investment) and a rate of return on the undepreciated portion of the investment (a return on the investment). The current design of the CORE programs, including a recovery of the Shareholder Incentive, does not track the loss profit PSNH experiences when it displaces sales in a manner equal to the method using lost fixed cost revenues; however, lost fixed cost recovery had become too unwieldy. The Shareholder Incentive provides some financial relief to PSNH but does not provide full compensation for lost fixed cost recovery or a traditional rate base/rate of return compensation through rates for supply side investments. PSNH believes these issues will be taken up generically in the so-called Decoupling proceeding, Docket No. DE 07-064.

A.3. Rates to Encourage Cost-Effective Investments in More Efficient Power Generation, Transmission and Distribution

PSNH is allowed to recover its prudently incurred costs of generation from customers who take Default Energy Service. Any shortfall or excess in the recovery of energy costs is reconciled through subsequent energy service revenue proceedings. For major modifications to its generating plants, PSNH must first obtain a public interest determination by the Commission and approval of a cost recovery mechanism. (RSA 369-B:3-a). RSA Chapter 125-O:5 allows PSNH to use unencumbered energy efficiency funds to make efficiency improvements and the Department of Environmental Services can offer additional emission allowances for such efficiency improvements that reduce emissions. (RSA Chapter 362-F). Distribution rates are set on a traditional historic rate base/rate of return basis. There are no specific incentives in those rates which encourage improvements in efficiency of the delivery function. However, the FERC has endorsed pricing policies and financial incentives to ensure the construction of necessary transmission infrastructure, including higher rates of return on equity for transmission investment.

A.4. Avoidance of Unfair Competitive Advantages over Small Businesses Engaged in Demand Side Energy Management Measures

PSNH's costs for demand side management programs are generally recovered through a portion of the revenues generated by the System Benefits Charge[21]. PSNH operates the CORE Energy Efficiency programs with the System Benefits Charge revenues; however, those services are delivered through local businesses. Energy efficient lighting products are sold through a catalogue. PSNH uses the catalogue more as an educational vehicle than a sales tool. The catalogue promotes new lighting fixtures which accept compact fluorescent lamps. The goal is to transform the market of home lighting by introducing fixtures and lamps that use more efficient compact fluorescent lamps, although those lamps are also sold through the catalogue. In addition to the catalogue, the utilities partner with ninety-one lighting retailers who provide rebates coupons for compact fluorescent lamps. The sales from these retailers exceed the sales from the catalogue by three to one. The CORE program utilities also work with seventy-five appliance retailers who provide rebates for Energy Star® appliances.

The Small Business Initiatives program is delivered by contractors who participate in a competitive bidding process. Customers are free to use their own contractor and receive modest rebates for the measures installed. The large commercial and industrial programs also depend upon equipment vendors, building contractors or energy service companies to install the measures. Rebates provided to the customer for energy efficient devices often make the difference between a customer purchasing and installing a standard device or upgrading to the more efficient device.

Home Energy Assistance is a residential efficiency program offered to low income customers. The services are delivered for the most part, by the Community Action Agencies. This partnership makes sense because it leverages U.S. Department of Energy Home Weatherization program funds to ensure that the maximum amount of home heating efficiency is gained in these low income families' homes. The Home Energy Solutions and Energy Star® Homes programs each rely on local contractors for delivery of program services.

PSNH's System Benefits Charge revenues support the CORE programs that supplement rather than supplant the small business sector that delivers energy efficient products and services. Existing businesses benefit from the subsidies provided through the programs. Because PSNH does not deliver the programs itself and relies upon local small businesses to provide services, there is no unfair competitive disadvantage to small business.

B. Conclusion

PSNH is in compliance with the Energy Policy Act of 1992. It files a plan biennially and the Commission conducts adjudicatory proceedings in evaluating that plan. Rates for demand-side investment are not commensurate with rates for generation, transmission and distribution; however, the Commission is exploring those issues in Docket No. DE 07-064. For the most part, state statutes and rates do not encourage cost effective investment in

[21] The modest cost of peak demand reduction programs is collected through the distribution rates.

generation and distribution; however, transmission rates set by the FERC encourage investment. Because PSNH does not deliver the programs itself and relies upon local small businesses to provide services, there is no unfair competitive disadvantage to small business.

XII. Assessment of the Plan's Long- and Short-Term Environmental, Economic, Energy Price, and Energy Supply Impact on the State

As environmental regulations become more stringent and fuel prices rise, the cost of electricity to New Hampshire's businesses and consumers will rise as well. This section discusses the impact that environmental regulations and volatile energy prices have on PSNH and New Hampshire's economy and the initiatives PSNH is undertaking to minimize the cost impact.

A. Environmental Regulations, Initiatives and Impacts

PSNH continuously monitors federal and state environmental regulations and legislative initiatives to determine their potential impact on PSNH's ownership of fossil-fuel generating assets. In addition to the Clean Air Act Amendments of 1990, there are several federal and state environmental regulations affecting PSNH. Some of the key regulations and initiatives include the federal Acid Rain Program, the Ozone Transport Region, the Clean Air Mercury Rule, the New Hampshire Clean Power Act, the Clean Air Interstate Rule and the Clean Water Act. The following sections discuss PSNH's compliance with the regulations and the impact of potential future environmental regulations.

A.1. Sulfur Dioxide (SO_2)

As a result of the federal Acid Rain Program requirements, a national SO_2 emissions allowance market has evolved. PSNH has participated in this market as a purchaser of SO_2 allowances. In addition to the federal Acid Rain Program requirements, SO_2 is regulated under the New Hampshire Clean Power Act, RSA Chapter 125-O and Env-A 2900, a state cap and trade program. Purchasing allowances, in combination with burning low-sulfur fuels, has been a cost effective means of complying with state and federal SO_2 requirements. This approach will continue to be employed until a wet flue gas desulphurization ("FGD" or "scrubber") is installed at Merrimack Station. With the passage of state legislation House Bill 1673 in June 2006, a scrubber is required to be installed at Merrimack Station for utilization on both Units 1 and 2 no later than June 2013. This scrubber installation has been required as a means to reduce mercury emissions, but has the additional benefit of reducing sulfur dioxide emissions. In the interim, PSNH will continue to purchase allowances and burn low-sulfur fuels in order to comply with federal and state SO_2 requirements including RSA Chapter 125-O and Env-A 2900.

Historically, SO_2 allowance market prices were attractively priced as a compliance alternative. In 2002, the SO_2 allowance market began experiencing upward pressure. Since that time, SO_2 allowance prices have been extremely volatile and increased substantially. In 2004, SO_2 allowance prices increased dramatically from approximately \$200 per ton at the beginning of the year to just over \$700 per ton at the end of the year and had increased to as high as approximately \$1,600 per ton in December 2005. Following a market high of approximately \$1,600 per ton, SO_2 allowance prices have decreased steadily during 2006, with current market prices fluctuating around \$500 per ton.

Implementation of the New Hampshire Clean Power Act in 2007 will increase the number of SO_2 allowances that PSNH will be required to purchase. The value of allowances to be used by PSNH in 2007 would be between $16 and $18 million if prices stayed at $500 per ton.

PSNH is currently in the process of obtaining permits and approvals, procuring resources and completing early engineering to install the scrubber at Merrimack Station by July 1, 2013. In the interim, PSNH's compliance strategy will continue to be based on a combination of purchasing of SO_2 allowances and burning of low-sulfur fuels.

PSNH's fuel purchasing group continually interacts with allowance brokers, on virtually a daily basis, and receives up-to-date market information. PSNH will continue to monitor the SO_2 allowance market for dips in market prices and make purchases for inventory build and use in future years.

Through proactive management PSNH has significantly reduced the SO_2 emissions from its fossil-fueled fired generating stations. For example, Merrimack Station has lowered its SO_2 emissions by more than 50 percent through fuel-switching to lower sulfur coals. PSNH will continue to explore additional reductions of SO_2 through proactive management.

A.2. Nitrogen Oxide (NOx)

PSNH has installed NOx pollution control equipment and implemented operational controls on each electric generating unit regulated under the New Hampshire NOx Budget Program, RSA Chapter 125-J and Env-A 3200, and the New Hampshire Clean Power Act, RSA Chapter 125-O and Env-A 2900. PSNH also has the option to purchase additional NOx allowances if necessary to comply with the requirements of the New Hampshire NOx Budget Program and the New Hampshire Clean Power Act. PSNH currently utilizes a combination of control equipment and market-based mechanisms to comply with the requirements of RSA Chapter 125-J and Env-A 3200, as well as RSA Chapter 125-O and Env-A 2900.

By way of background, the New Hampshire NOx Budget Program is a market-based budget (or cap) and trading program that was implemented in New Hampshire following the signing of the Ozone Transport Commission Memorandum of Understanding ("OTC MOU") in 1994. The New Hampshire NOx Budget Program was designed to achieve ozone season (summer) NOx reductions greater than those required by the OTC MOU. Since the implementation of the program, the statewide annual budget has been decreased from 4,674 tons beginning in 1999, to 3,739 tons beginning in 2003, and 3,000 tons beginning in 2006. The caps result in significant reductions from the 1990 baseline level of 14,589 tons. Initially, only PSNH's electric generating units were regulated under the New Hampshire NOx Budget Program, however, beginning in 2003, the program was expanded to include two new combined cycle natural gas power plants, Newington Energy and Granite Ridge LLC.

The New Hampshire NOx Budget Program is an output-based, allocation market-based cap and trade program. Under the program, regulated units receive a percentage of the statewide annual budget directly proportional to the unit's average generation produced during the prior two ozone seasons. Regulated units may install NOx control technology or purchase additional allowances on an open market should their NOx emissions be greater than the number of direct allocations received. Regulated units may sell allowances or bank allowances for future use should their NOx emissions be less than the number of direct allocations received. By November 30th each year, a regulated unit must hold allowances in its account equal to the total tons of NOx emitted during the ozone season.

The NOx emission allowance market evolved in the Northeast, specifically the Ozone Transport Region ("OTC"), following the implementation of the OTC NOx Budget Program in 1999. Historically, PSNH has participated in this market as a seller of NOx allowances. The installation of NOx control equipment at Merrimack Station in 1995 allowed PSNH to create early reduction allowances, which were then sold into the market. The revenue generated from the sale of these allowances enabled PSNH to purchase additional NOx and particulate matter emissions control equipment without any impact on customers. The operation of NOx emissions control equipment at PSNH's generating stations, and the subsequent sale of NOx allowances, was a cost effective means of meeting state and federal NOx emissions reduction requirements.

The NOx emission allowance market, similar to the SO2 market, has at times been volatile, but is currently experiencing downward pricing pressure. This downward pressure resulted in NOx allowance prices falling during 2006 and 2007 from prices in excess of $2,100 per ton to current day prices of approximately $600 per ton.

PSNH's ability to participate in the NOx allowance market ended in 2003 due to the decision by the State of New Hampshire not to "opt in" to the SIP Call NOx Budget Program. Not opting in has resulted in New Hampshire administering its own state NOx Budget Program. Under a state NOx Budget Program, allowances generated in New Hampshire are only eligible for sale within the state. Currently, there is no demand for NOx allowances within the state. PSNH is, however, able to purchase NOx allowances generated outside of New Hampshire should the need arise.

PSNH monitors the sale price of allowances and, as in the case of the SO_2 allowance market, the fuel purchasing group continually interacts with the allowance brokers. PSNH will continue to monitor the NOx allowance market and make purchases for inventory consolidation to use in future years should the sale price of allowances decrease below the cost of creating NOx reductions at its generating stations.

Through proactive management and the installation of emissions control equipment, PSNH has achieved significant reductions in NOx emissions from its fossil-fueled fired generating stations since 1995. PSNH will continue to explore additional reductions of NOx through proactive management, operation and optimization of existing control equipment and potential installation of additional control equipment.

A.3. Mercury (Hg)

On March 15, 2005, the EPA published a rule that modified its so-called "Regulatory Determination" that regulation of Hazardous Air Pollutant emissions from Electric Utility Steam Generating Units was "appropriate and necessary." On the same day, EPA finalized the Clean Air Mercury Rule that controls mercury emissions through a cap and trade program.

EPA has adopted a two-pronged approach to controlling mercury emissions from coal-fired EUSGUs larger than 25 MW:

- New or reconstructed units are subject to output-based New Source Performance Standards ("NSPS") created for mercury; and

- New and existing units are subject to a two-stage, nationwide, cap and trade program for mercury.

The present level of mercury emissions from coal-fired EUSGUs in the United States is estimated to be about 48 tons per year. EPA has established the following two nationwide emission caps:

- 2010 – 38 tons per year
- 2018 – 15 tons per year

The earlier cap represents the reductions that EPA estimates can be achieved through implementation of controls on nitrogen oxides (NOx) and sulfur dioxide (SO_2), mandated by a companion rule, the Clean Air Interstate Rule ("CAIR"). The later cap represents reductions that can be achieved through mercury-specific controls, such as activated carbon injection.

Each state is assigned a "budget" of allowances, each representing one pound of emitted mercury. Each state budget is based on each affected unit's portion of the national baseline heat input, adjusted to account for coal type. The budget for New Hampshire is as follows:

- 2010 – 0.063 tons (126 pounds)
- 2018 – 0.025 tons (50 pounds)

The states have the option to participate in the cap and trade program. Each participant state may allocate its allowance budget to the affected facilities within the state, as it sees fit. For non-participant states, the allowance budget becomes a fixed, enforceable emission limit for the state. The states may adopt more stringent controls on EUSGUs or regulate other source categories if they wish.

Currently, there is no mercury emissions allowance market; however, beginning in 2010 allowance trading will be allowed under the federal program similar to that in the Acid Rain Program. Banking of allowances will also be allowed, without restriction. However, states may impose more stringent limitations and prohibit participation in the trading program.

New Hampshire's legislature passed House Bill 1673, an amendment to the New Hampshire Clean Power Act, in June 2006 requiring a reduction in mercury emissions from the affected units as defined in the New Hampshire Clean Power Act. Only Merrimack and Schiller Stations are subject to the mercury requirements implemented under the New

Hampshire Clean Power Act, specifically Merrimack Units 1 and 2, and Schiller Units 4 , 5, and 6. At the state level, trading of mercury emissions is not allowed under the New Hampshire Clean Power Act.

PSNH assisted Legislators, NHDES, and other stakeholders during the development of House Bill 1673 to assess the economic impact of installing a scrubber system on Merrimack Stations Unit 1 and Unit 2. NHDES determined that the best known commercially available technology was a wet flue gas desulphurization system or scrubber, as it best balanced the procurement, installation, operation, and plant efficiency costs with the projected reductions in mercury and other pollutants from the flue gas streams of Merrimack Units 1 and 2. Scrubber technology achieves significant emissions reduction benefits, including but not limited to, cost effective reductions in sulfur dioxide, sulfur trioxide, small particulate matter, and improved visibility (regional haze). This decision considered capital, operating, fuel (coal), and emissions credits (SO_2) estimated costs; and determined that this approach provided not only an environmental benefit to customers, but also an economic benefit to customers over the life of the project.

Under House Bill 1673, PSNH is required to install a scrubber at Merrimack Station for utilization on both Units 1 and 2 no later than June 2013. The scrubber technology is required as a means to reduce mercury emissions, but has the additional benefit of reducing sulfur dioxide emissions. Pending the installation of the scrubber, PSNH is required to test and implement, as practicable, mercury reduction control technologies or methods to achieve early reductions in mercury emissions.

PSNH completed the stack testing initially required to measure mercury emissions consistent with the July 2007 deadline. PSNH also completed an initial fuel analysis program, consisting of a minimum of twelve monthly analyses, to document the mercury content in coal prior to the July 2007 deadline. Additional fuel analyses and stack testing have also been completed and will be submitted to the New Hampshire Department of Environmental Services, Air Resources Division as required by House Bill 1673.

In light of the technical and economic feasibility of mercury control at Merrimack Station, PSNH proposed that the New Hampshire Department of Environmental Services ("NHDES") consider interim solutions for mercury reductions pending the implementation of a mercury cap consistent with the federal mercury regulation. Implementing mercury reduction opportunities with a focus on performance results is consistent with the Multiple Pollutant Reduction Program and the New Hampshire Mercury Reduction Strategy.

PSNH identified a number of technical and operational control strategies and pilot projects that will quantify the results of additional mercury reductions, such as fuel switching/washing, modifying flyash reinjection and carbon additives. This interim approach would result in near-term, cost-effective, mercury reductions and allow New Hampshire to meet the goal of House Bill 1673 which incented local reductions as available in the short term with the more significant reduction associated with a scrubber installation at Merrimack Station in the long term.

PSNH will continue to monitor the development of new mercury control technology and mercury continuous emissions monitoring equipment to determine whether there are cost-effective ways to further reduce mercury emissions.

A.4. Carbon Dioxide (CO_2)

Carbon dioxide compliance options currently include repowering or retiring existing electric generating units, curtailing operations and purchasing power, investing in efficiency projects, new renewable energy projects, and conservation and load management projects. Control technology is not commercially available. PSNH may also purchase and use CO_2 allowances from federal or regional trading and banking programs, or other programs acceptable to NHDES, to comply with the CO_2 emission cap established under RSA 125-O:3, III. Currently there are no federal or regional trading and banking programs. Other programs acceptable to the NHDES potentially may include emissions trading markets both within the United States, such as the Chicago Climate Exchange, and outside of the United States, such as the European Union Emissions Trading Scheme.

The market value of credits traded on the CCX has been far less volatile than the value of emissions allowances traded on the EU ETS. The market value of emissions credits traded on the CCX has increased gradually from approximately $0.95/ton in December 2003 to $3.60/ton on April 9, 2007.

The market value of allowances traded on the European Union Emissions Trading Scheme market has been highly volatile since trading began in January 2005, when allowances were traded at approximately €7 per ton. During the first year of trading, allowance prices experienced both a record high of €29.50 per ton on July 7, 2005 and a record low of €6.20 per ton on January 10, 2005. During April 2006, allowance prices fell significantly from a high of €30 per ton to €11 per ton as a result of lower than expected emissions reported for 2005. The market value of EU ETS allowances has continued to decline since April 2006, with allowances trading at approximately €9 per ton in May 2006 and €5.50 per ton in January 2007. During the March and April 2007, EU ETS allowances were trading between €1.30 per ton and €0.83 per ton, reaching yet another record low market value of €0.83 per ton on April 10, 2007.

In March 2004, the recommendation to the Legislature made by the NHDES Air Resources Division ("ARD") also included a Phase II cap for carbon dioxide emissions from PSNH's fossil fueled electric generating stations. The NHDES ARD recommended a Phase II cap of 4,069,400 tons beginning with calendar year 2011, however, legislation implementing a Phase II CO_2 cap has not been enacted.

PSNH anticipates that the NHDES ARD will work toward the implementation of a second phase CO_2 cap in New Hampshire and a regional greenhouse gas/emissions trading program, which would include CO_2. NHDES ARD is currently participating in the Regional Greenhouse Gas Initiative ("RGGI"), a cooperative effort by nine Northeast and Mid-Atlantic states to discuss the design of a regional cap-and-trade program initially covering carbon dioxide emissions from power plants in the region.

Although the New Hampshire Clean Power Act allows PSNH to achieve reductions of CO_2 emissions under a cap and trade program, there is currently no state or federal trading program for CO_2. The development of a CO_2 emissions market at the federal level is dependent upon the implementation of federal CO_2 reduction requirements under a national cap and trade program. Currently there is no commercially available air pollution control equipment to control CO_2 emissions.

The New Hampshire Clean Power Act allows PSNH to earn bonus CO_2 allowances that may be used to offset emissions above the cap. Under the provisions of RSA Chapter 125-O, NHDES ARD will provide CO_2 allowances to PSNH for qualifying energy efficiency and new renewable energy projects, equivalent to the amount of such allowances that could have been purchased at market prices by the same dollar amount as the expenditure made. The installation of a wood-fired boiler at Schiller Station, Northern Wood Power, qualifies as a renewable energy project under New Hampshire air pollution control regulations. This project has also qualified as a renewable energy project in Massachusetts and Rhode Island. PSNH submitted a request for bonus CO_2 allowances for investments made in renewable energy projects at Schiller Station and Smith Hydro with NHDES ARD on April 16, 2007.

As indicated in the compliance plan previously filed with NHDES ARD, PSNH will utilize a combination of production adaptations and market-based mechanisms to comply with the CO_2 requirements in RSA Chapter 125-O and Env-A 2900. In addition, PSNH will continue to undertake projects that qualify for the energy efficiency, new renewable energy and conservation and load management bonus CO_2 allocations provided under RSA Chapter 125-O and Env-A 2906.06. Lastly, PSNH will monitor the development of legislation specific to the second phase CO_2 cap, as well as the development of regional and national programs regulating CO_2.

A.5. Clean Water Act of 1972

<u>Section §316(a) – Thermal Discharge</u>

The Clean Water Act requires a facility to "assure the projection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the body of water."

The discharge of pollutants, including heat, from the station to the river is specifically governed by PSNH's National Pollutant Discharge Elimination System (NPDES) permit.

To date, Merrimack Station has controlled the release of heat to the river by discharging water through a cooling canal. The canal in concert with floating "power spray modules" operated within specific guidelines on a seasonal basis minimizes the thermal output of the cooling water into the river. EPA is in the process of re-issuing Merrimack Station's NPDES permit.

For the last several years, PSNH has been performing fisheries studies and river modeling to provide information to the agencies. This information assists the agencies in determining the most appropriate means to regulate the thermal discharge from PSNH's facilities. This effort will be finishing up within the next year. The data gathered to date demonstrates that the thermal discharge from the plant has not had an adverse environmental effect on the aquatic population over the course of plant operations. As a result, when the NPDES permit is issued in the near future, the thermal limits should be consistent with current operating parameters and have minimal operational impacts. However, in the last year, EPA Region I has taken a more aggressive regulatory stance in setting thermal limits at other plants in the New England region, and may seek to impose more restrictive limits in the Merrimack Station permit, requiring the installation of technological controls to further reduce thermal loading. Cooling towers are the most costly compliance option with estimates ranging from $15 million to $40 million. Operating and maintenance costs, loss of power costs, efficiency losses, etc. would all be extra costs not included in the estimates. At this point, PSNH can not predict if further thermal restrictions will be imposed on Merrimack Station.

Section §316(b) – Withdrawal of Cooling Water

Section §316(b) of the Clean Water Act of 1972 requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. EPA has issued a series of rules designed to protect aquatic organisms from being killed or injured by impingement (being pinned against screens or other parts of a cooling water intake structure) or entrainment (being drawn into cooling water systems and subjected to thermal, physical or chemical stresses).

The rulemaking was implemented in three phases:

- Phase I rule, promulgated in 2001, covers new facilities.
- Phase II rule, promulgated in 2004, covers large existing electric generating plants.
- Phase III rule, proposed November 1, 2004, covers small existing facilities.

PSNH's three fossil stations fall under the Phase II Rule. As a result, PSNH was preparing to submit Comprehensive Demonstration Studies ("CDS") as required by the Rule. The purpose of the CDS was to characterize impingement mortality and entrainment, describe the operation of the cooling water intake structures, and confirm that technologies and/or operational measures that had been selected and installed, or would be installed within an approved timeframe, would comply with the Rule.

However, on January 25, 2007, the United States Court of Appeals for the Second Circuit issued its decision in a lawsuit challenging the Phase II Rule (known as "*Riverkeeper II*"), remanding key components of the Rule to EPA for reconsideration. Shortly thereafter, EPA formally suspended the Phase II Rule and directed the EPA regional offices to develop permit requirements relating to cooling water intake structures on a site-specific best professional judgment basis, requiring facilities to use the best technology available to minimize adverse environmental impact from their cooling water intake structures.

However, despite the *Riverkeeper II* decision and the Rule's suspension, PSNH will need to continue to develop and provide much of the same information to EPA, including impingement and entrainment monitoring data.

In addition, on June 26, 2007, EPA issued an information request letter to PSNH seeking information to assist EPA in developing permit limits for Merrimack Station. PSNH has hired an engineering consultant to assist in preparation of the information requested by EPA. PSNH expects to demonstrate that operation of the Station's existing cooling water intake structures has not resulted in adverse environmental impact to the aquatic ecosystems of the Merrimack River and that the Station's existing cooling water intake structure configuration and operational practices are, in fact, best technology available. However, at this time, there is a high degree of regulatory uncertainty in light of the *Riverkeeper II* decision, which is being appealed to the U.S. Supreme Court, and suspension of the Phase II Rule. PSNH cannot predict the outcome at this time although it is likely that PSNH, at a minimum, will have to install an improved fish return system and perform additional monitoring. However, it is possible that EPA could require the installation of a helper cooling tower or a full cooling tower.

B. Uncertain and Evolving New England Market

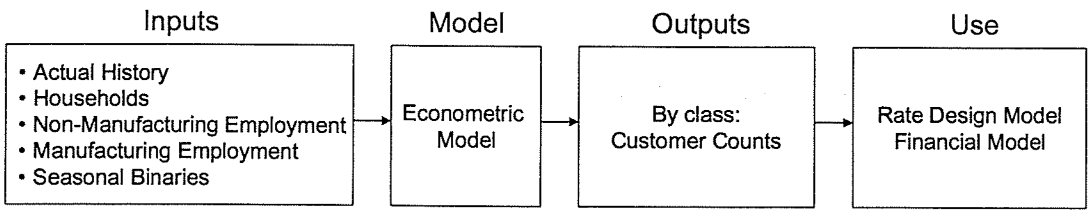
In general, the wholesale electricity market and the supply/demand situation are evolving, with further changes to come. PSNH believes there will be a continuing evolution of wholesale electric market rules in the New England wholesale market overseen by ISO-New England. The operation of the New England wholesale market, and the rules implemented therein, have a significant impact on the retail electricity prices in New England.

In addition, the federal regulation of transmission systems and services is also going through an evolution. Clearly, transmission is viewed as a regional system within New England, and beyond. Moreover, there are significant transmission congestion issues in New England which have not been fully resolved. Similar to the regional wholesale electricity market rules of the ISO-New England, regional transmission services and policies have a significant impact on retail customers in New Hampshire and throughout New England.

XIII. Appendix A – Financial and Business Planning Forecasting Models

This appendix provides a more detailed discussion of the methodologies to forecast customer counts, delivery energy sales, system peak load, and delivery hourly loads for use in financial and business planning.

A. Customer Counts

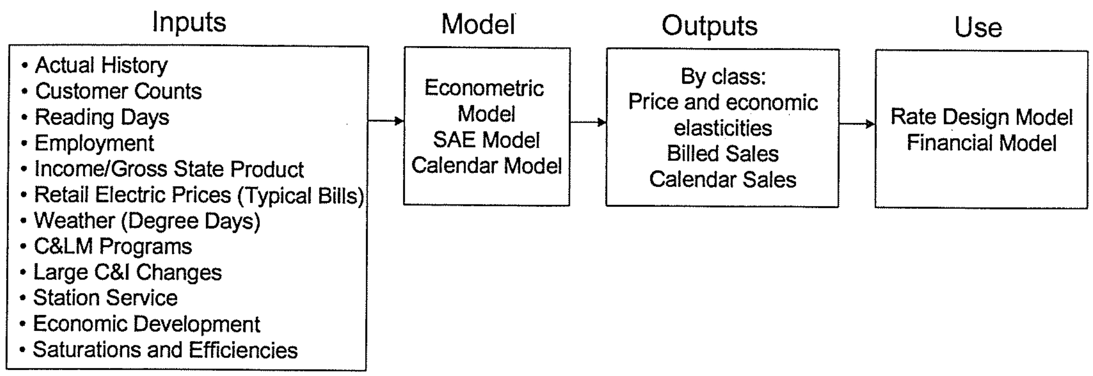


The class customer count equations were estimated using historical data from January 1990 to February 2007, depending on the class of customer. Separate econometric models are used to forecast customers, with customers as a function of households (residential), non-manufacturing employment (commercial), manufacturing employment (industrial), or a trend (streetlighting). The equations below describe the independent variables used to develop the customer count class models.

ResCustCount$_m$ = f(EconDemo$_m$, MonBinary, CVECBinary, LagDependent)
ComCustCount$_m$ = f(EconDemo$_m$, CVECBinary, LagDependent)
IndCustCount$_m$ = f(EconDemo$_m$)
StlCustCount$_m$ = f(Stl Customer Trend)

where:
m = Month
EconDemo$_m$ = Monthly economic and demographic variables specific to the class (i.e., households, non-manufacturing employment, manufacturing employment)
MonBinary = Monthly binary variables
CVECBinary = Binary variable to adjust for CVEC acquisition in 2004
LagDependent = Lagged dependent variable

B. Delivery Energy Sales



Methodology

PSNH's monthly delivery energy forecast is developed by class and reflects local economic and demographic conditions. Economic and demographic forecasts for New Hampshire are produced based on a model developed by Moody's Economy.com for the state of New Hampshire and the United States. The sales forecast is developed by class by various end uses and incorporates assumptions to reflect customers' response to price changes, conservation programs, economic development efforts and other known changes. Sales forecasts are disaggregated by end use to study detailed trends that affect energy consumption and to provide input to the hourly energy and peak load forecasts.

Step 1: Econometric Model

ResUsePerDay$_m$ = f(HDD_RD$_m$, CDD_RD$_m$, Price$_m$, EconDemo$_m$, LagDependent)
ComUse$_m$ = f(HDD$_m$, CDD$_m$, RD$_m$, Price$_m$, EconDemo$_m$, CVECBinary, LagDependent)
IndUse$_m$ = f(CDD$_m$, RD$_m$, Price$_m$, EconDemo$_m$)
StlUse$_m$ = f(ResCustm, MonBinary$_m$, AuditBinary$_m$)

where:
m = Month
HDD_RD$_m$ = Heating degree days per reading day per month
CDD_RD$_m$ = Cooling degree days per reading day per month
HDD$_m$ = Heating degree days per month
CDD$_m$ = Cooling degree days per month
RD$_m$ = Reading days per month
Price$_m$ = 12 month moving average typical bill per month
EconDemo$_m$ = Monthly economic and demographic variables specific to the class (i.e., income, non-manufacturing employment, manufacturing employment, manufacturing gross state product)
MonBinary = Monthly binary variables
CVECBinary = Binary variable to adjust for CVEC acquisition
AuditBinary = Streetlighting audit binary variable

LagDependent = Lagged dependent variable

The end result of the models described above is class specific elasticities to use in SAE models for residential and commercial classes and Trend sales for industrial and streetlighting classes. SAE models are not available for the industrial and streetlighting classes.

Step 2: Statistically Adjusted End-Use Model

In 2006, the Company joined Itron's Energy Forecasting Group and began using their Statistically Adjusted End-Use Models ("SAE") for the residential and commercial classes. Itron, a nationally recognized expert in end-use forecasting, developed the SAE methodology, which is being used by many electric and gas utilities around the country. The SAE models use regional end-use data from the U.S. Department of Energy's Energy Information Administration to develop independent variables that are used in traditional econometric models.

The SAE modeling framework begins by defining energy use ($Use_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathbf{Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m}}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathbf{Use_{y,m} = b_1 \times XHeat_{y,m} + b_2 \times XCool_{y,m} + b_3 \times XOther_{y,m}}$$

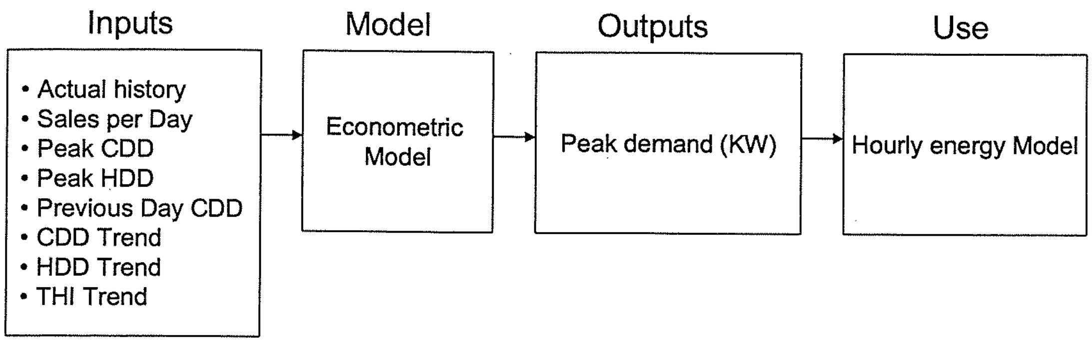
Here, $XHeat_{y,m}$, $XCool_{y,m}$ and $XOther_{y,m}$ are explanatory variables constructed from end-use information, dwelling, weather, economic and price data. The equations used to construct these X-variables maintain an end-use structure as the X-variables are the estimated usage levels for each of the major end uses. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors which scale the regional data to the Company's sales.

For the residential class, Trend sales equal the number of customers times use per customer and for the customer class, Trend sales equals use. The industrial and streetlighting sales Trend forecasts are based on traditional econometric models because SAE models are not available for the industrial or streetlighting classes.

Step 3: Adjustments to Forecast

The final step in developing the Reference case forecast is to make adjustments either up or down to account for Conservation and Load Management losses, Economic Development gains, Large Commercial and Industrial gains or losses, Seabrook Station Service gains, and a final adjustment to convert billed sales into calendar sales. The end result is the Reference forecast.

C. Peak Load Demand



Methodology

The Reference Peak Demand forecast is created in order to develop the hourly energy forecast. It is not used for system planning purposes. The forecast for system planning is described in greater detail in section III.D. The forecasted peaks are derived from an econometric model where monthly peaks are a function of weather, Reference forecast sales per reading day, and a weather trend. Since the C&LM and economic development assumptions are already included in Reference energy sales, which the peak demand forecast is based on, no explicit adjustments are made to the peak model results.

The Reference or Base Case Peak Demand forecast, as a 50/50 forecast, assumes normal weather throughout the year, with normal peak-producing weather episodes in each season. The forecasted mean daily temperature for the summer peak day is 80° Fahrenheit ("°F") and for the winter peak day is 5° Fahrenheit ("°F") and is based on the average peak-day temperatures from 1977-2006.

The historical peak-day mean temperatures range from 73° F to 87° F in the summer and from -8° F to 27° F in the winter with deviations from the average peak-day temperatures being random, recurring and unpredictable occurrences. For example, the lowest summer peak-day mean temperature occurred in 2000, while the highest summer peak-day mean temperature occurred in 2006. The highest winter peak-day mean temperature occurred in 1993 and the lowest winter peak-day mean temperature occurred in 2001. This variability of peak-producing weather means that over the forecast period there will be years when the actual peaks will be significantly above or below forecasted peaks.

The following econometric equation is used to derive the non-coincident peak demand forecast:

$$\mathbf{NCPeak_{y,m} = b_1 \times SalesPerDay_{y,m} + b_2 \times PeakCDD_{y,m} + b_3 \times PeakHDD_{y,m} + b_4 \times PeakYestCDD_{y,m} + b_5 \times HDDTrend_{y,m} + b_6 \times CDDTrend_{y,m} + b_7 \times THITrend_{y,m}}$$

where:
y = Year
m = Month
$SalesPerDay_{y,m}$ = Total Company Sales (includes Wholesale Sales) per reading day per month
$PeakCDD_{y,m}$ = Cooling degree days on the day of the monthly peak
$PeakHDD_{y,m}$ = Heating degree days on the day of the monthly peak
$PeakYestCDD_{y,m}$ = Cooling degree days on the day before the peak day
$HDDTrend_{y,m}$ = Heating degree days trend
$CDDTrend_{y,m}$ = Cooling degree days trend
$THITrend_{y,m}$ = Temperature-Humidity Index trend

D. Hourly Energy Use

The hourly energy forecast is used as an input into the supplemental energy purchase forecast. To develop the hourly energy forecast, the monthly sales and monthly peaks are combined into an econometric model and the shape of the line is adjusted so that the hourly loads add up to the monthly energy from the Reference Delivery Energy Sales forecast and the highest hour matches the monthly peaks from the Reference Peak Demand forecast.

The hourly loads for each year include company use, wholesale requirements, and losses and are divided by a delivery efficiency factor of 0.942 to convert into a pool transmission level. This is the base forecast of system electrical energy requirements or output and is the amount of energy which must be supplied by generating plants or power purchases to serve the loads on the system.

XIV. Appendix B – Financial and Business Planning Forecast Scenarios

This appendix provides a more detailed discussion of the scenario analysis for the forecasted customer counts, delivery energy sales, system peak load, and hourly load.

A. Customer Counts Scenario Analysis

- The Base Case Customer forecast is based on an average annual growth rate of 1.4 percent for households, 1.6 percent for non-manufacturing employment, and -0.3 percent for manufacturing employment.
- The Low Growth Case Customer forecast is based on an average annual growth rate of 1.3 percent for households, 0.6 percent for non-manufacturing employment, and -1.8 percent for manufacturing employment.
- The High Growth Case Customer forecast is based on an average annual growth rate of 1.6 percent for households, 2.6 percent for non-manufacturing employment, and 1.4 percent for manufacturing employment.

PSNH Annual Customer History and Forecast - Base Case										
Year	**Res**	**% Chg**	**Com**	**% Chg**	**Ind**	**% Chg**	**Stl**	**% Chg**	**Total**	**% Chg**
History										
2002	382,481		61,775		2,818		509		447,583	
2003	388,133	1.5%	63,324	2.5%	2,758	-2.1%	523	2.7%	454,738	1.6%
2004	403,088	3.9%	66,572	5.1%	2,783	0.9%	536	2.6%	472,979	4.0%
2005	408,959	1.5%	68,232	2.5%	2,768	-0.5%	563	4.9%	480,521	1.6%
2006	413,980	1.2%	69,528	1.9%	2,761	-0.3%	554	-1.6%	486,823	1.3%
Compound Annual Growth Rates (2002-2006)										
	2.0%		3.0%		-0.5%		2.1%		2.1%	
Forecast										
2007	419,430	1.3%	70,490	1.4%	2,763	0.1%	574	3.6%	493,258	1.3%
2008	425,522	1.5%	71,859	1.9%	2,757	-0.2%	583	1.6%	500,721	1.5%
2009	431,682	1.4%	73,081	1.7%	2,757	0.0%	593	1.7%	508,114	1.5%
2010	437,852	1.4%	74,229	1.6%	2,756	0.0%	603	1.7%	515,441	1.4%
2011	444,252	1.5%	75,337	1.5%	2,755	0.0%	613	1.6%	522,957	1.5%
2012	451,362	1.6%	76,475	1.5%	2,754	0.0%	623	1.6%	531,215	1.6%
Compound Annual Growth Rates (2006-2012)										
	1.5%		1.6%		0.0%		2.0%		1.5%	

PSNH Annual Customer History and Forecast - Low Growth Case										
Year	Res	% Chg	Com	% Chg	Ind	% Chg	Stl	% Chg	Total	% Chg
History										
2002	382,481		61,775		2,818		509		447,583	
2003	388,133	1.5%	63,324	2.5%	2,758	-2.1%	523	2.7%	454,738	1.6%
2004	403,088	3.9%	66,572	5.1%	2,783	0.9%	536	2.6%	472,979	4.0%
2005	408,959	1.5%	68,232	2.5%	2,768	-0.5%	563	4.9%	480,521	1.6%
2006	413,980	1.2%	69,528	1.9%	2,761	-0.3%	554	-1.6%	486,823	1.3%
Compound Annual Growth Rates (2002-2006)										
	2.0%		3.0%		-0.5%		2.1%		2.1%	
Forecast										
2007	418,918	1.2%	70,429	1.3%	2,757	-0.1%	574	3.6%	492,678	1.2%
2008	424,482	1.3%	71,751	1.9%	2,745	-0.4%	583	1.6%	499,561	1.4%
2009	430,161	1.3%	72,938	1.7%	2,739	-0.2%	593	1.7%	506,432	1.4%
2010	435,742	1.3%	74,053	1.5%	2,734	-0.2%	603	1.7%	513,133	1.3%
2011	441,513	1.3%	75,129	1.5%	2,729	-0.2%	613	1.6%	519,983	1.3%
2012	447,892	1.4%	76,235	1.5%	2,723	-0.2%	623	1.6%	527,473	1.4%
Compound Annual Growth Rates (2006-2012)										
	1.3%		1.5%		-0.2%		2.0%		1.3%	

PSNH Annual Customer History and Forecast - High Growth Case										
Year	Res	% Chg	Com	% Chg	Ind	% Chg	Stl	% Chg	Total	% Chg
History										
2002	382,481		61,775		2,818		509		447,583	
2003	388,133	1.5%	63,324	2.5%	2,758	-2.1%	523	2.7%	454,738	1.6%
2004	403,088	3.9%	66,572	5.1%	2,783	0.9%	536	2.6%	472,979	4.0%
2005	408,959	1.5%	68,232	2.5%	2,768	-0.5%	563	4.9%	480,521	1.6%
2006	413,980	1.2%	69,528	1.9%	2,761	-0.3%	554	-1.6%	486,823	1.3%
Compound Annual Growth Rates (2002-2006)										
	2.0%		3.0%		-0.5%		2.1%		2.1%	
Forecast										
2007	420,103	1.5%	70,526	1.4%	2,772	0.4%	574	3.6%	493,975	1.5%
2008	426,753	1.6%	71,938	2.0%	2,773	0.0%	583	1.6%	502,047	1.6%
2009	433,386	1.6%	73,198	1.8%	2,779	0.2%	593	1.7%	509,955	1.6%
2010	440,141	1.6%	74,383	1.6%	2,784	0.2%	603	1.7%	517,910	1.6%
2011	447,177	1.6%	75,528	1.5%	2,788	0.2%	613	1.6%	526,106	1.6%
2012	455,033	1.8%	76,704	1.6%	2,793	0.2%	623	1.6%	535,152	1.7%
Compound Annual Growth Rates (2006-2012)										
	1.6%		1.7%		0.2%		2.0%		1.6%	

B. Delivery Energy Sales Scenario Analysis

- The Base Case Delivery Energy Sales forecast is based on an average annual growth rate of 3.1 percent for real personal income, 1.6 percent for non-manufacturing employment, -0.3 percent for manufacturing employment, and 1.9 percent for real manufacturing gross state product.
- The Low Growth Case Delivery Energy Sales forecast is based on an average annual growth rate of 2.4 percent for households, 0.6 percent for non-manufacturing employment, -1.8 percent for manufacturing employment, and 0.2 percent for real manufacturing gross state product. Electric prices are assumed to increase by 10 percent in 2008 and remain at a constant real price in 2009-2012.
- The High Growth Case Delivery Energy Sales forecast is based on an average annual growth rate of 3.9 percent for households, 2.6 percent for non-manufacturing employment, 1.4 percent for manufacturing employment, and 3.7 percent for real manufacturing gross state product. Electric prices are assumed to decrease by 10 percent in 2008 and remain at a constant real price in 2009-2012.

PSNH Annual Calendar Sales History and Forecast (GWH) - Base Case

Year	Res	% Chg	Com	% Chg	Ind	% Chg	Stl	% Chg	Total	% Chg
History (Weather Normalized)										
2002	2,771		2,958		1,634		23		7,386	
2003	2,880	3.9%	3,045	2.9%	1,659	1.5%	23	0.6%	7,607	3.0%
2004	3,036	5.4%	3,251	6.8%	1,723	3.9%	25	4.8%	8,034	5.6%
2005	3,102	2.2%	3,296	1.4%	1,592	-7.6%	24	-0.5%	8,014	-0.2%
2006	3,118	0.5%	3,341	1.4%	1,574	-1.1%	23	-5.4%	8,057	0.5%
Compound Annual Growth Rates (2002-2006)										
	3.0%		3.1%		-0.9%		-0.2%		2.2%	
Forecast										
2007	3,185	2.1%	3,427	2.6%	1,584	0.7%	25	6.3%	8,222	2.0%
2008	3,229	1.4%	3,564	4.0%	1,585	0.0%	25	1.1%	8,402	2.2%
2009	3,298	2.1%	3,681	3.3%	1,599	0.9%	25	0.8%	8,603	2.4%
2010	3,375	2.3%	3,788	2.9%	1,612	0.8%	25	0.8%	8,799	2.3%
2011	3,458	2.5%	3,913	3.3%	1,610	-0.1%	25	0.8%	9,006	2.3%
2012	3,559	2.9%	4,049	3.5%	1,626	1.0%	26	0.9%	9,260	2.8%
Compound Annual Growth Rates (2006-2012)										
	2.2%		3.3%		0.5%		1.8%		2.3%	

PSNH Annual Calendar Sales History and Forecast (GWH) - Low Growth Case										
Year	**Res**	**% Chg**	**Com**	**% Chg**	**Ind**	**% Chg**	**Stl**	**% Chg**	**Total**	**% Chg**
History (Weather Normalized)										
2002	2,771		2,958		1,634		23		7,386	
2003	2,880	3.9%	3,045	2.9%	1,659	1.5%	23	0.6%	7,607	3.0%
2004	3,036	5.4%	3,251	6.8%	1,723	3.9%	25	4.8%	8,034	5.6%
2005	3,102	2.2%	3,296	1.4%	1,592	-7.6%	24	-0.5%	8,014	-0.3%
2006	3,118	0.5%	3,341	1.4%	1,574	-1.1%	23	-5.4%	8,057	0.5%
Compound Annual Growth Rates (2002-2006)										
	3.0%		3.1%		-0.9%		-0.2%		2.2%	
Forecast										
2007	3,179	1.9%	3,426	2.5%	1,569	-0.3%	25	6.3%	8,198	1.8%
2008	3,203	0.8%	3,550	3.6%	1,543	-1.6%	25	1.1%	8,320	1.5%
2009	3,250	1.5%	3,654	2.9%	1,532	-0.7%	25	0.8%	8,460	1.7%
2010	3,317	2.1%	3,753	2.7%	1,530	-0.1%	25	0.8%	8,625	1.9%
2011	3,392	2.3%	3,871	3.2%	1,515	-0.9%	25	0.8%	8,804	2.1%
2012	3,482	2.7%	4,001	3.3%	1,519	0.2%	26	0.9%	9,027	2.5%
Compound Annual Growth Rates (2006-2012)										
	1.9%		3.0%		-0.6%		1.8%		1.9%	

PSNH Annual Calendar Sales History and Forecast (GWH) - High Growth Case										
Year	**Res**	**% Chg**	**Com**	**% Chg**	**Ind**	**% Chg**	**Stl**	**% Chg**	**Total**	**% Chg**
History (Weather Normalized)										
2002	2,771		2,958		1,634		23		7,386	
2003	2,880	3.9%	3,045	2.9%	1,659	1.5%	23	0.6%	7,607	3.0%
2004	3,036	5.4%	3,251	6.8%	1,723	3.9%	25	4.8%	8,034	5.6%
2005	3,102	2.2%	3,296	1.4%	1,592	-7.6%	24	-0.5%	8,014	-0.3%
2006	3,118	0.5%	3,341	1.4%	1,574	-1.1%	23	-5.4%	8,057	0.5%
Compound Annual Growth Rates (2002-2006)										
	3.0%		3.1%		-0.9%		-0.2%		2.2%	
Forecast										
2007	3,190	2.3%	3,430	2.6%	1,608	2.2%	25	6.3%	8,253	2.4%
2008	3,250	1.9%	3,576	4.3%	1,635	1.6%	25	1.1%	8,486	2.8%
2009	3,329	2.4%	3,702	3.5%	1,667	2.0%	25	0.8%	8,724	2.8%
2010	3,412	2.5%	3,815	3.1%	1,694	1.6%	25	0.8%	8,946	2.6%
2011	3,504	2.7%	3,947	3.5%	1,708	0.8%	25	0.8%	9,184	2.7%
2012	3,615	3.1%	4,090	3.6%	1,739	1.8%	26	0.9%	9,469	3.1%
Compound Annual Growth Rates (2006-2012)										
	2.5%		3.4%		1.7%		1.8%		2.7%	

C. Peak Demand Scenario Analysis

- The Reference Plan Peak Demand forecast is based on normal peak day weather (80°F mean daily summer temperature, 5°F mean daily winter temperature).
- The High Peak Demand forecasts are based on the weather that occurred on the 2006 summer peak day (87°F mean daily temperature) and on the 1993 winter peak day (-8°F mean daily temperature).
- The Low Peak Demand forecasts are based on the weather that occurred on the 2000 summer peak day (73°F mean daily temperature) and on the 2001 winter peak day (27°F mean daily temperature).

50/50 Case and Extreme Weather Scenarios for Summer Peak											
	Net Electrical Energy Output Requirements		Reference Plan (50/50 Case)			Extreme Hot Scenario			Extreme Cool Scenario		
Year	Output	Annual Change	Peak	Annual Change	Load Factor	Peak	Annual Change	Load Factor	Peak	Annual Change	Load Factor
	GWH	(%)	MW	(%)	(2)	MW	(%)	(2)	MW	(%)	(2)
History											
2002	7,968		1,575		0.577						
2003	8,249	3.5%	1,556	-1.2%	0.605						
2004	8,495	3.0%	1,525	-2.0%	0.634						
2005	8,655	1.9%	1,729	13.4%	0.571						
2006	8,489	-1.9%	1,786	3.3%	0.542						
Compound Rates of Growth (2002-2006)											
	1.6%		3.2%								
History Normalized for Weather											
2002	7,950		1,508		0.602						
2003	8,157	2.6%	1,498	-0.7%	0.622						
2004	8,539	4.7%	1,552	3.6%	0.626						
2005	8,529	-0.1%	1,670	7.6%	0.583						
2006	8,511	-0.2%	1,650	-1.2%	0.589						
Compound Rates of Growth (2002-2006)											
	1.7%		2.3%								
Forecast											
2007	8,731	2.9%	1,682	-5.8%	0.593	1,822	2.0%	0.547	1,546	-13.5%	0.645
2008	8,923	2.2%	1,702	1.2%	0.597	1,849	1.5%	0.549	1,558	0.8%	0.652
2009	9,136	2.4%	1,738	2.1%	0.600	1,892	2.3%	0.551	1,587	1.8%	0.657
2010	9,345	2.3%	1,781	2.5%	0.599	1,944	2.7%	0.549	1,623	2.3%	0.657
2011	9,564	2.3%	1,828	2.6%	0.597	1,997	2.8%	0.547	1,663	2.4%	0.657
2012	9,834	2.8%	1,870	2.3%	0.599	2,047	2.5%	0.547	1,698	2.1%	0.659
Compound Rates of Growth (2006-2012)											
	2.5%		0.8%			2.3%			-0.8%		
Normalized Compound Rates of Growth (2006-2012)											
	2.4%		2.1%			3.7%			0.5%		

Notes:
1. Sales plus losses and company use.
2. Load Factor = Output (MWh) / (8760 Hours X Season Peak (MW)).

50/50 Case and Extreme Weather Scenarios for Winter Peak												
	Net Electrical Energy Output Requirements		Reference Plan (50/50 Case)			Extreme Cold Scenario			Extreme Warm Scenario			
Year	Output	Annual Change	Peak	Annual Change	Load Factor	Peak	Annual Change	Load Factor	Peak	Annual Change	Load Factor
	GWH	(%)	MW	(%)	(2)	MW	(%)	(2)	MW	(%)	(2)
History											
2002	7,968		1,365		0.667						
2003	8,249	3.5%	1,471	7.8%	0.640						
2004	8,495	3.0%	1,458	-0.8%	0.663						
2005	8,655	1.9%	1,419	-2.7%	0.696						
2006	8,489	-1.9%	1,418	-0.1%	0.683						
Compound Rates of Growth (2002-2006)											
	1.6%		1.0%								
History Normalized for Weather											
2002	7,950		1,401		0.648						
2003	8,157	2.6%	1,405	0.3%	0.663						
2004	8,539	4.7%	1,518	8.1%	0.640						
2005	8,529	-0.1%	1,419	-6.5%	0.686						
2006	8,511	-0.2%	1,442	1.6%	0.674						
Compound Rates of Growth (2002-2006)											
	1.7%		0.7%								
Forecast											
2007	8,731	2.9%	1,440	1.6%	0.692	1,508	6.4%	0.661	1,326	-6.5%	0.752
2008	8,923	2.2%	1,465	1.7%	0.693	1,535	1.8%	0.662	1,346	1.6%	0.754
2009	9,136	2.4%	1,484	1.3%	0.703	1,557	1.4%	0.670	1,362	1.1%	0.766
2010	9,345	2.3%	1,502	1.2%	0.710	1,577	1.3%	0.676	1,376	1.0%	0.775
2011	9,564	2.3%	1,542	2.6%	0.708	1,619	2.7%	0.674	1,411	2.6%	0.774
2012	9,834	2.8%	1,561	1.3%	0.717	1,641	1.4%	0.682	1,427	1.1%	0.785
Compound Rates of Growth (2006-2012)											
	2.5%		1.6%			2.5%			0.1%		
Normalized Compound Rates of Growth (2006-2012)											
	2.4%		1.3%			2.2%			-0.2%		

Notes:
1. Sales plus losses and company use.
2. Load Factor = Output (MWh) / (8760 Hours X Season Peak (MW)).

XV.Appendix C – Engineering Forecasts by Area

The following exhibits show the engineering forecasts by area.

Exhibit C-1: Lakes Region Summer Peak Loads

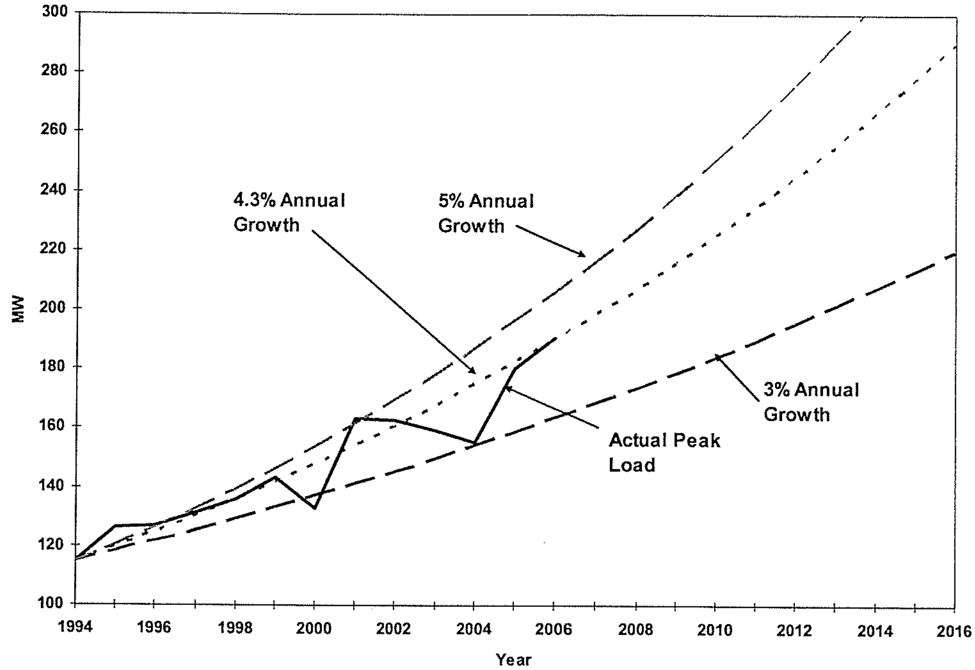


Exhibit C-2: Derry Area Summer Peak Loads

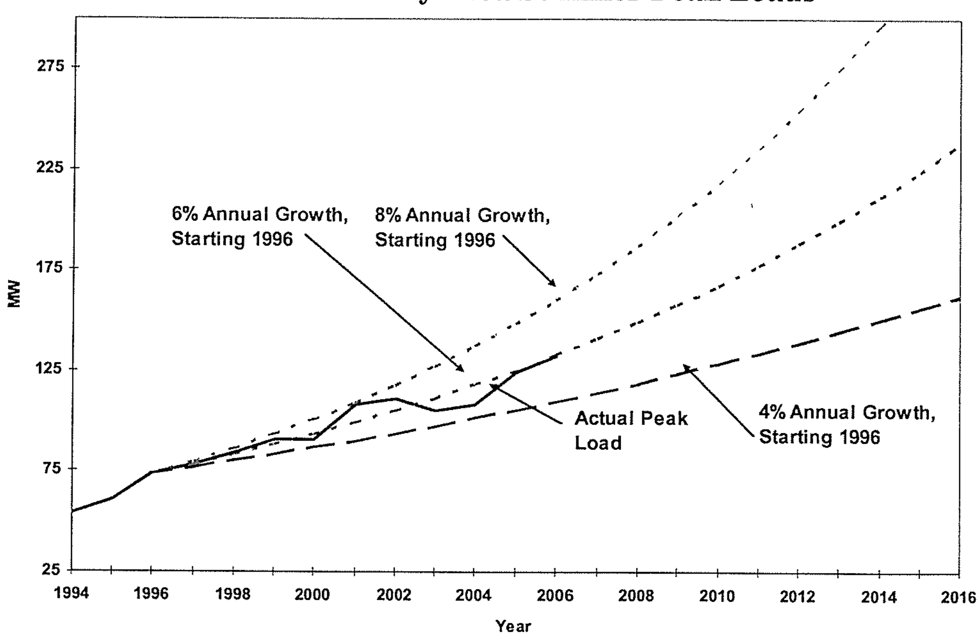


Exhibit C-3: Dover/Rochester Area Summer Peak Loads

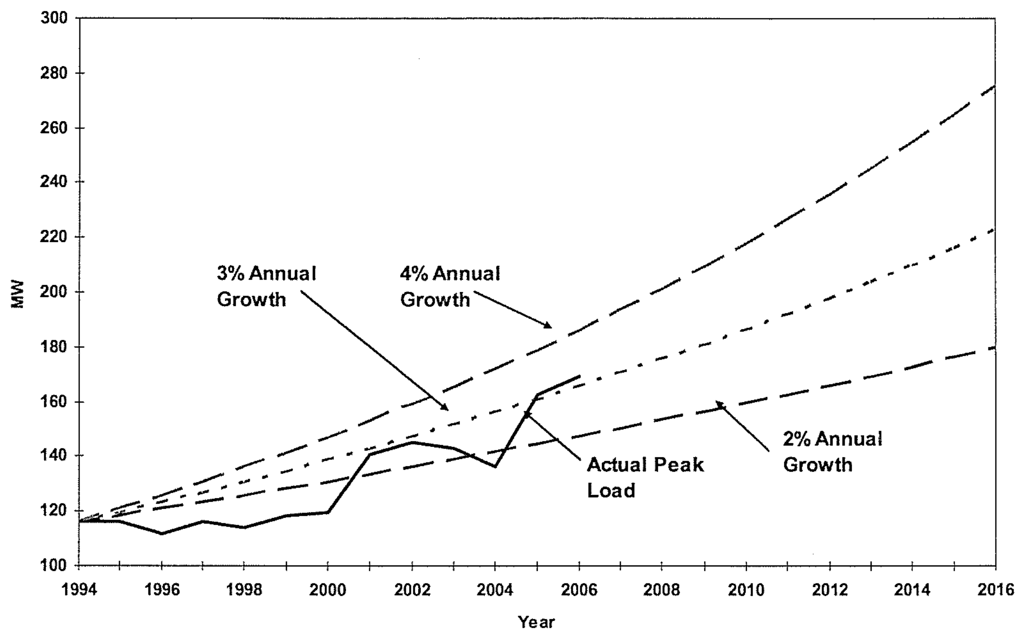


Exhibit C-4: Manchester Area Summer Peak Loads

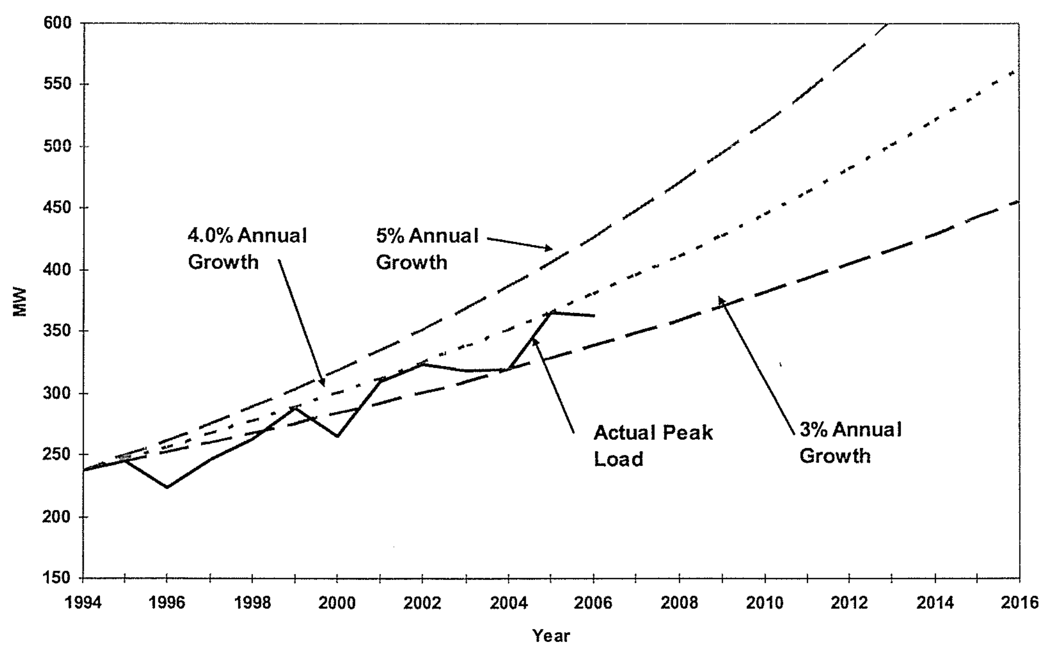


Exhibit C-5: Sunapee Area Summer Peak Loads

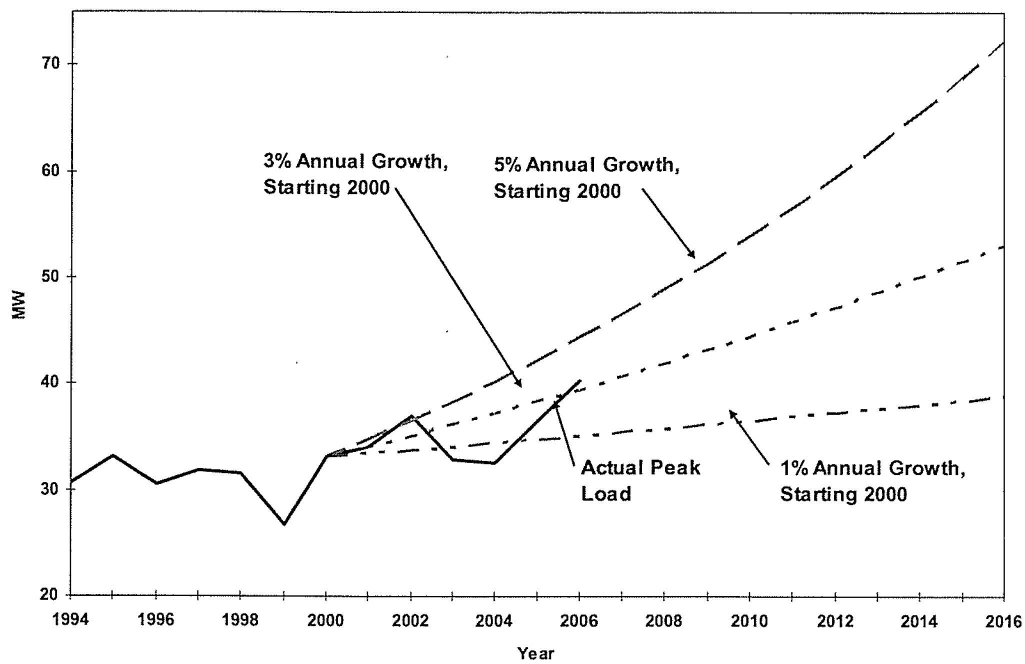


Exhibit C-6: Berlin/Lancaster Area Summer Peak Loads

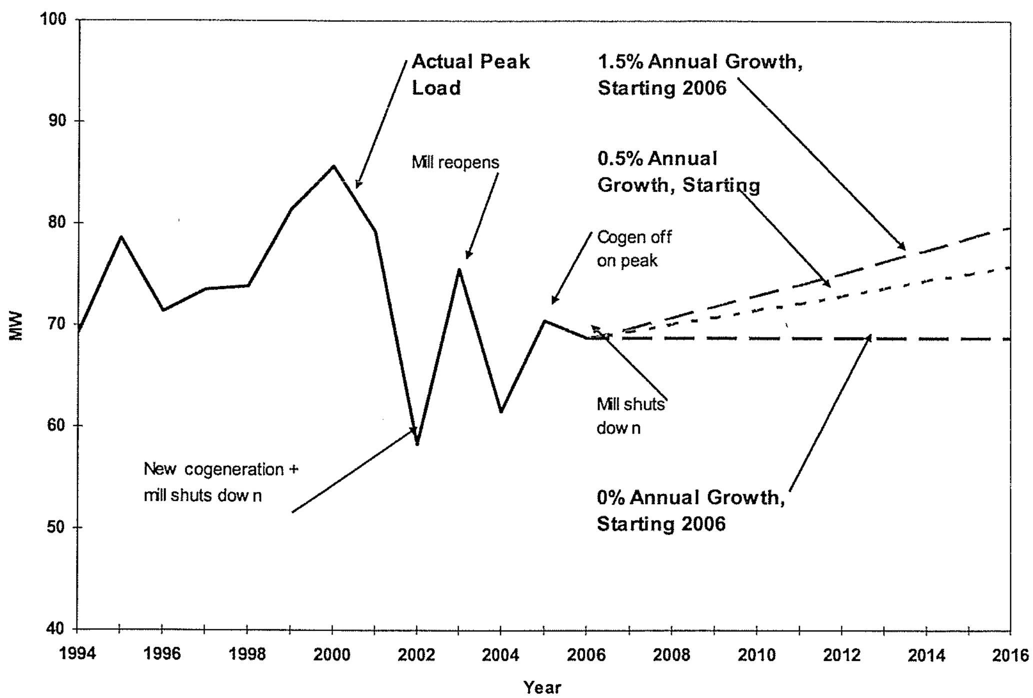


Exhibit C-7: Portsmouth Area Summer Peak Loads

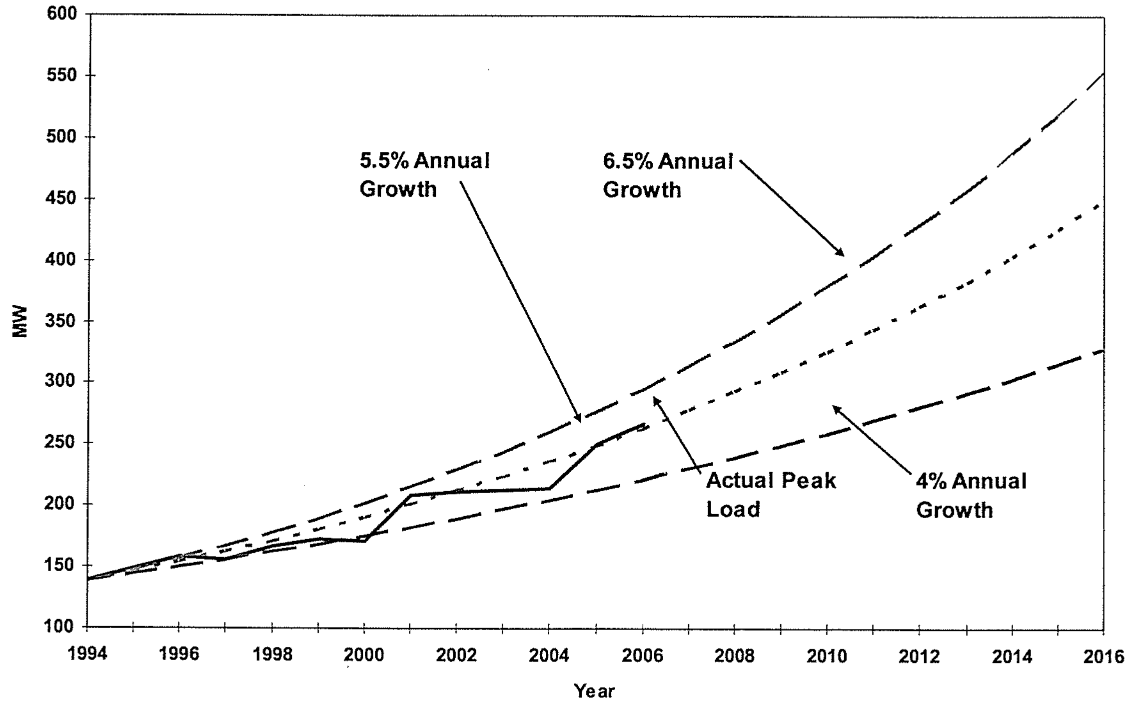


Exhibit C-8: Nashua-Milford Area Summer Peak Loads

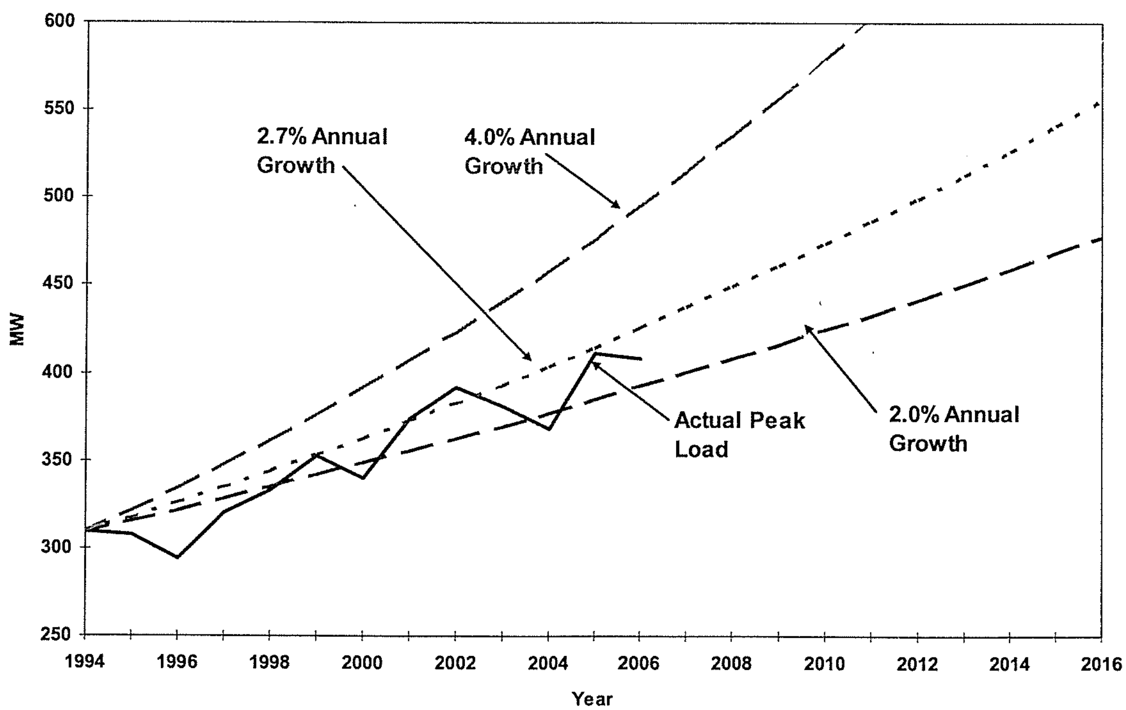


Exhibit C-9: Western Area Summer Peak Loads

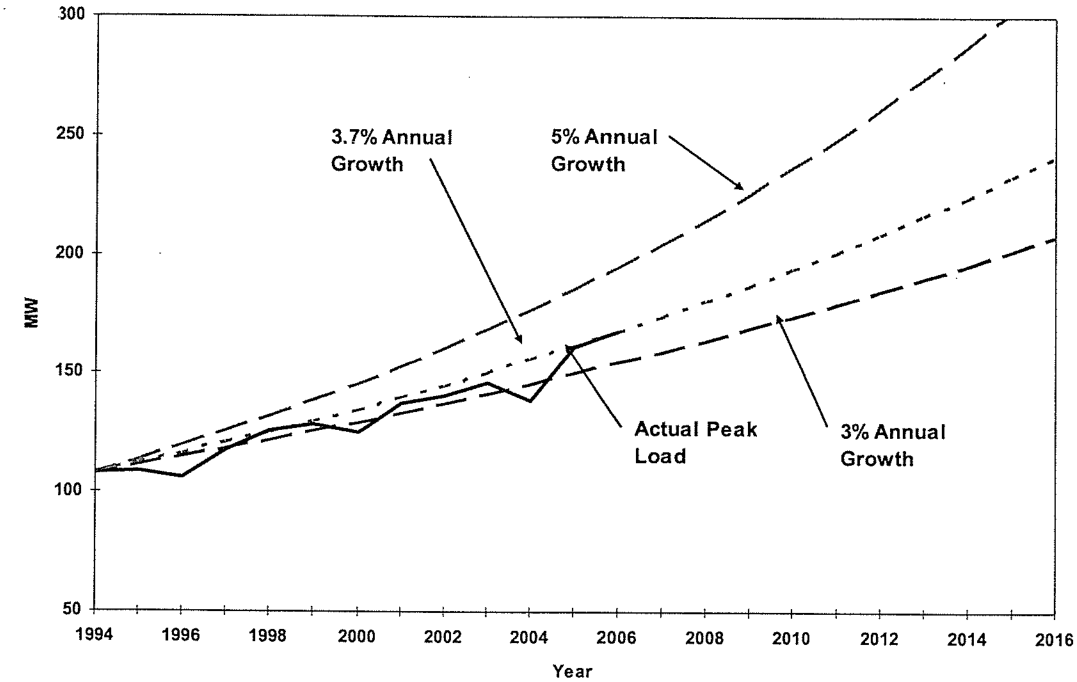


Exhibit C-10: Conway/Ossipee Area Summer Peak Loads

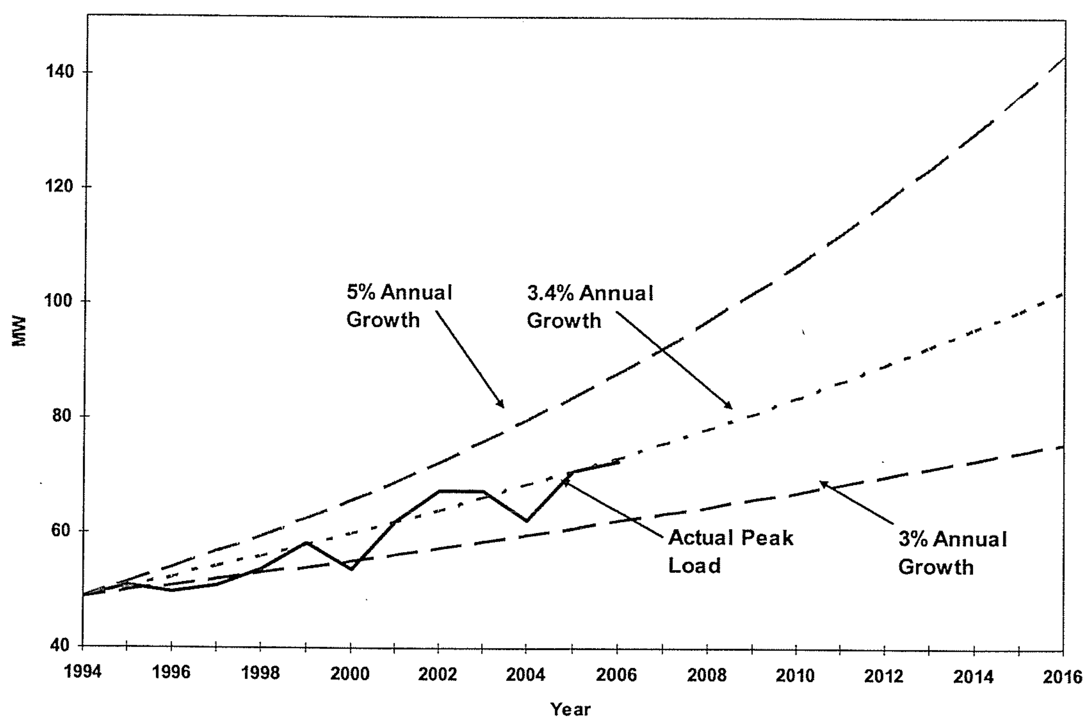


Exhibit C-11: UES Seacoast Area Summer Peak Loads

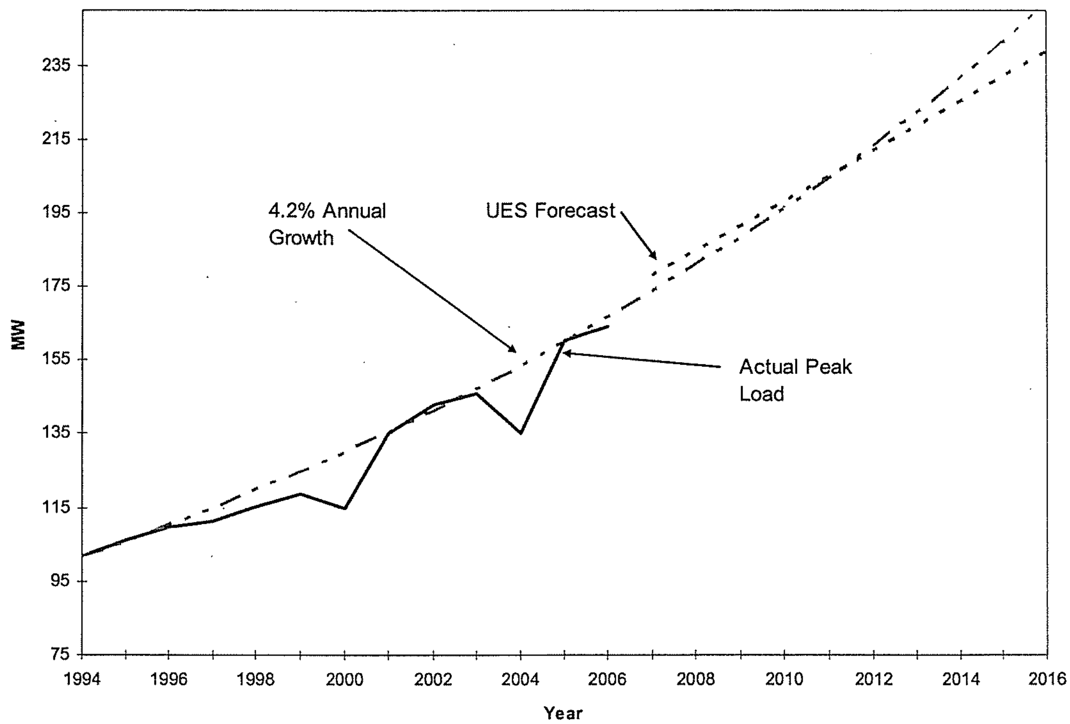


Exhibit C-12: UES Capital Area Summer Peak Loads

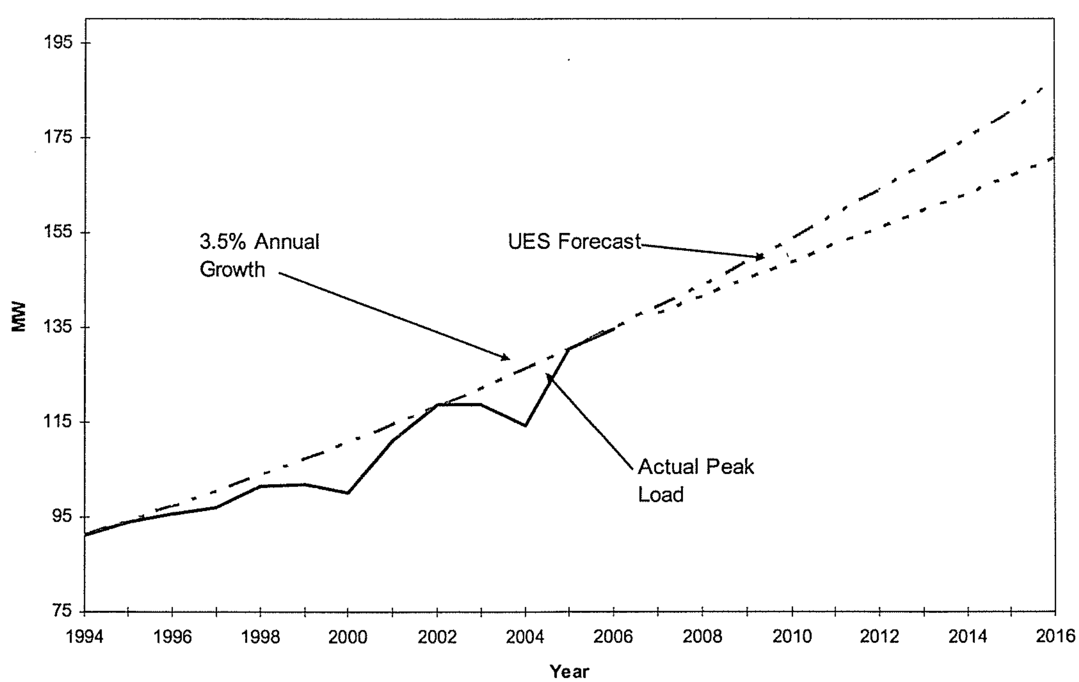
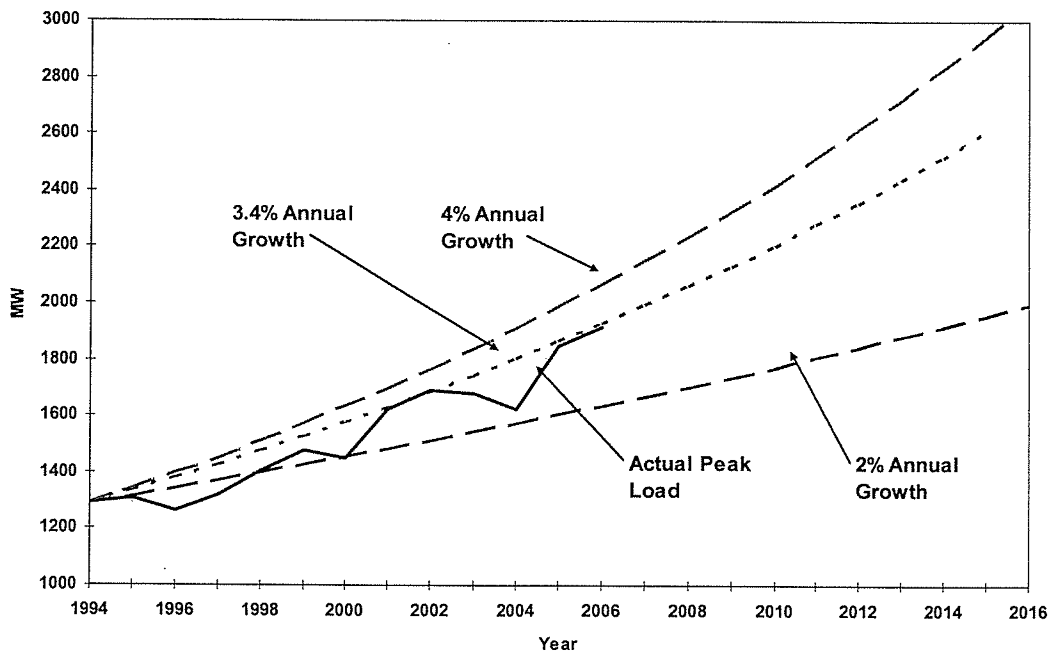


Exhibit C-13: PSNH Summer Peak Loads



XVI. Appendix D – PSNH Supply Resources Used to Serve Energy Requirement

Exhibit D-1: On-Peak Supply Resources Used to Serve 2006 Energy Requirement

On-Peak			Portion of Requirement Served by...								
	Energy Requirement MWh	PSNH Resource Subtotal	IPP	Buyout Contracts	Vermont Yankee	Hydro	Merrimack and Schiller	Newington and Wyman	Bilateral Purchase	ISO-New England Spot Purchases	Combustion Turbines
Jan	378,161	90%	11%	2%	2%	5%	47%	23%	9%	1%	0.00%
Feb	351,359	69%	11%	2%	2%	5%	43%	7%	29%	2%	0.02%
Mar	382,713	73%	11%	2%	2%	4%	54%	0%	27%	0%	0.00%
Apr	295,470	64%	12%	1%	3%	6%	39%	4%	36%	0%	0.00%
May	332,438	47%	12%	0%	2%	5%	25%	3%	51%	2%	0.01%
Jun	380,125	67%	11%	1%	2%	5%	45%	3%	31%	2%	0.05%
Jul	388,685	70%	9%	1%	2%	3%	42%	14%	24%	5%	0.12%
Aug	411,647	65%	9%	1%	2%	1%	43%	8%	27%	8%	0.04%
Sep	308,811	49%	9%	0%	2%	1%	36%	0%	50%	1%	0.00%
Oct	324,639	69%	12%	1%	2%	3%	51%	0%	31%	0%	0.01%
Nov	325,793	71%	13%	1%	2%	4%	50%	0%	29%	0%	0.00%
Dec	344,598	65%	11%	1%	2%	4%	43%	4%	32%	2%	0.00%
Totals	4,224,439	67%	11%	1%	2%	4%	43%	6%	31%	2%	0.02%

Exhibit D-2: Off-Peak Supply Resources Used to Serve 2006 Energy Requirement

Off-Peak			Portion of Requirement Served by...								
	Energy Requirement MWh	PSNH Resource Subtotal	IPP	Buyout Contracts	Vermont Yankee	Hydro	Merrimack and Schiller	Newington and Wyman	Bilateral Purchase	ISO-New England Spot Purchases	Combustion Turbines
Jan	358,490	89%	14%	3%	2%	6%	59%	4%	8%	3%	0.02%
Feb	312,068	77%	13%	3%	2%	6%	53%	0%	12%	11%	0.01%
Mar	306,604	90%	14%	3%	3%	5%	65%	0%	7%	3%	0.00%
Apr	280,789	77%	15%	1%	3%	7%	49%	0%	21%	2%	0.02%
May	277,135	61%	16%	0%	3%	7%	33%	0%	26%	14%	0.00%
Jun	284,287	85%	15%	1%	3%	7%	58%	0%	13%	2%	0.00%
Jul	377,185	78%	13%	1%	3%	5%	55%	1%	21%	2%	0.00%
Aug	296,328	80%	12%	1%	3%	2%	60%	1%	19%	1%	0.00%
Sep	289,040	66%	12%	1%	3%	1%	49%	0%	21%	13%	0.01%
Oct	268,828	89%	16%	1%	3%	4%	65%	0%	10%	1%	0.00%
Nov	280,721	90%	16%	1%	3%	6%	63%	0%	10%	0%	0.00%
Dec	350,132	80%	15%	1%	3%	5%	56%	0%	16%	4%	0.00%
Totals	3,681,609	80%	14%	2%	3%	5%	56%	1%	15%	5%	0.01%

"Buyout Contracts" refers to IPP Replacement Purchases (BioEnergy & Whitefield).
"PSNH Resource Subtotal" is the sum of all columns except Bilateral and Spot purchases.

Exhibit D-2: PSNH Total Energy Resource Requirement Gap

	2008	2009	2010	2011	2012	Expiration
Merrimack Unit 1	751,054	884,881	793,906	884,881	796,293	
Merrimack Unit 2	2,073,123	2,175,520	2,175,520	2,175,520	2,182,051	
Schiller Unit 4	307,070	282,417	318,452	293,688	301,347	
Schiller Unit 5	335,340	332,433	332,433	318,829	333,344	
Schiller Unit 6	322,733	293,147	326,236	320,046	294,080	
Newington	263,759	206,710	176,854	165,617	163,296	
Merrimack CT1	0	0	0	0	0	
Merrimack CT2	0	0	0	0	0	
Schiller CT	0	0	0	0	0	
Lost Nation	0	0	0	0	0	
White Lake	0	0	0	0	0	
Amoskeag	88,779	88,779	88,779	88,779	88,779	
Garvins / Hooksett	49,662	49,662	49,662	49,662	49,662	
Eastman Falls	23,709	23,709	23,709	23,709	23,709	
Ayers Island	43,451	43,451	43,451	43,451	43,451	
Smith	100,075	100,075	100,075	100,075	100,075	
Gorham	12,325	12,325	12,325	12,325	12,325	
Canaan	7,474	7,474	7,474	7,474	7,474	
Jackman	9,246	9,246	9,246	9,246	9,246	
Vermont Yankee	168,366	178,695	168,414	168,398	40,118	
Wyman 4	0	0	0	0	0	
Tamworth Power	42,700	0	0	0	0	Mar 2008
West Hopkinton Hydro	3,300	3,300	3,300	3,300	3,025	Oct 2012
Garland Mill	33	33	33	33	28	Nov 2012
Penacook Lower Falls	18,800	18,800	18,800	18,800	18,800	2013
Rollinsford Hydro	6,000	6,000	6,000	6,000	6,000	2013
Great Falls Lower	3,400	3,400	3,400	3,400	3,400	2014
Newfound Hydro	6,000	6,000	6,000	6,000	6,000	2014
Nashua Hydro	4,300	4,300	4,300	4,300	4,300	2014
Steels Pond Hydro	2,600	2,600	2,600	2,600	2,600	2014
Watson Dam	1,000	1,000	1,000	1,000	1,000	2015
Sugar River Hydro	600	600	600	600	600	2015
Four Hills Landfill	4,800	4,800	4,800	4,800	4,800	2016
Peterborough Lower Hydro	900	900	900	900	900	2018
Peterborough Upper Hydro	1,100	1,100	1,100	1,100	1,100	2018
WES Concord MSW	103,000	103,000	103,000	103,000	103,000	2019
Penacook Upper Falls	13,900	13,900	13,900	13,900	13,900	2021
Briar Hydro	21,100	21,100	21,100	21,100	21,100	2022
Errol Dam	17,000	17,000	17,000	17,000	17,000	2023
BioEnergy Buyout	75,842	75,843	75,843	75,843	75,842	2015
Total Energy Resources (GWH)	4,883	4,972	4,910	4,945	4,729	
Energy Requirement Forecast (GWH)	8,923	9,136	9,345	9,564	9,834	
Supplemental Purchase Requirement (GWH)	4,041	4,164	4,435	4,619	5,105	

Exhibit D-3: PSNH On-Peak Energy Resource Requirement Gap

	2008	2009	2010	2011	2012
Merrimack Unit 1	349,072	413,722	372,644	413,743	371,339
Merrimack Unit 2	967,383	1,017,229	1,021,203	1,017,229	1,017,496
Schiller Unit 4	143,068	132,045	149,477	137,320	140,526
Schiller Unit 5	156,168	155,439	156,046	149,078	155,439
Schiller Unit 6	150,366	137,059	153,129	149,644	137,139
Newington	263,759	206,710	176,854	165,617	163,296
Merrimack CT1	0	0	0	0	0
Merrimack CT2	0	0	0	0	0
Schiller CT	0	0	0	0	0
Lost Nation	0	0	0	0	0
White Lake	0	0	0	0	0
Amoskeag	41,398	41,511	41,673	41,511	41,398
Garvins / Hooksett	23,158	23,221	23,312	23,221	23,158
Eastman Falls	11,056	11,086	11,129	11,086	11,056
Ayers Island	20,261	20,317	20,396	20,317	20,261
Smith	46,665	46,793	46,976	46,793	46,665
Gorham	5,747	5,763	5,785	5,763	5,747
Canaan	3,485	3,495	3,508	3,495	3,485
Jackman	5,048	5,048	5,048	5,048	5,048
Vermont Yankee	78,408	83,554	78,985	78,651	19,151
Wyman 4	0	0	0	0	0
Tamworth Power	19,911	0	0	0	0
West Hopkinton Hydro	1,539	1,543	1,549	1,543	1,411
Garland Mill	15	15	15	15	13
Penacook Lower Falls	8,766	8,791	8,825	8,791	8,766
Rollinsford Hydro	2,798	2,805	2,816	2,805	2,798
Great Falls Lower	1,585	1,590	1,596	1,590	1,585
Newfound Hydro	2,798	2,805	2,816	2,805	2,798
Nashua Hydro	2,005	2,011	2,018	2,011	2,005
Steels Pond Hydro	1,212	1,216	1,220	1,216	1,212
Watson Dam	466	468	469	468	466
Sugar River Hydro	280	281	282	281	280
Four Hills Landfill	2,238	2,244	2,253	2,244	2,238
Peterborough Lower Hydro	420	421	422	421	420
Peterborough Upper Hydro	513	514	516	514	513
WES Concord MSW	48,029	48,161	48,349	48,161	48,029
Penacook Upper Falls	6,482	6,499	6,525	6,499	6,482
Briar Hydro	9,839	9,866	9,904	9,866	9,839
Errol Dam	7,927	7,949	7,980	7,949	7,927
BioEnergy Buyout	35,368	35,472	35,612	35,472	35,363
Total Energy Resources (GWH)	2,417	2,436	2,399	2,401	2,293
Energy Requirement Forecast (GWH)	4,812	4,950	5,052	5,121	5,224
Supplemental Purchase Requirement (GWH)	2,395	2,515	2,652	2,720	2,931
Suppl Purchase Req w/ Newington on Reserve (GWH)	2,659	2,721	2,829	2,886	3,094
Avg Supp Capacity Req with Newington on Reserve (MW)	649	664	688	705	755
Avg Supp Capacity Req with Newington as Base Load (MW)	249	264	288	305	355

Exhibit D-4: PSNH Off-Peak Energy Resource Requirement Gap

	2008	2009	2010	2011	2012
Merrimack Unit 1	401,982	471,159	421,263	471,138	424,954
Merrimack Unit 2	1,105,740	1,158,290	1,154,317	1,158,290	1,164,555
Schiller Unit 4	164,002	150,372	168,975	156,368	160,820
Schiller Unit 5	179,172	176,994	176,387	169,751	177,905
Schiller Unit 6	172,367	156,088	173,107	170,402	156,940
Newington	0	0	0	0	0
Merrimack CT1	0	0	0	0	0
Merrimack CT2	0	0	0	0	0
Schiller CT	0	0	0	0	0
Lost Nation	0	0	0	0	0
White Lake	0	0	0	0	0
Amoskeag	47,381	47,268	47,106	47,268	47,381
Garvins / Hooksett	26,504	26,441	26,350	26,441	26,504
Eastman Falls	12,653	12,623	12,580	12,623	12,653
Ayers Island	23,190	23,134	23,055	23,134	23,190
Smith	53,410	53,282	53,099	53,282	53,410
Gorham	6,578	6,562	6,540	6,562	6,578
Canaan	3,989	3,979	3,966	3,979	3,989
Jackman	4,198	4,198	4,198	4,198	4,198
Vermont Yankee	89,958	95,141	89,429	89,747	20,967
Wyman 4	0	0	0	0	0
Tamworth Power	22,789	0	0	0	0
West Hopkinton Hydro	1,761	1,757	1,751	1,757	1,614
Garland Mill	18	18	18	18	15
Penacook Lower Falls	10,034	10,009	9,975	10,009	10,034
Rollinsford Hydro	3,202	3,195	3,184	3,195	3,202
Great Falls Lower	1,815	1,810	1,804	1,810	1,815
Newfound Hydro	3,202	3,195	3,184	3,195	3,202
Nashua Hydro	2,295	2,289	2,282	2,289	2,295
Steels Pond Hydro	1,388	1,384	1,380	1,384	1,388
Watson Dam	534	532	531	532	534
Sugar River Hydro	320	319	318	319	320
Four Hills Landfill	2,562	2,556	2,547	2,556	2,562
Peterborough Lower Hydro	480	479	478	479	480
Peterborough Upper Hydro	587	586	584	586	587
WES Concord MSW	54,971	54,839	54,651	54,839	54,971
Penacook Upper Falls	7,418	7,401	7,375	7,401	7,418
Briar Hydro	11,261	11,234	11,196	11,234	11,261
Errol Dam	9,073	9,051	9,020	9,051	9,073
BioEnergy Buyout	40,474	40,371	40,231	40,371	40,479
Total Energy Resources (GWH)	2,465	2,537	2,511	2,544	2,435
Energy Requirement Forecast (GWH)	4,111	4,186	4,293	4,443	4,610
Supplemental Purchase Requirement (GWH)	1,646	1,649	1,783	1,899	2,174
Suppl Purchase Req w/ Newington on Reserve (GWH)	1,646	1,649	1,783	1,899	2,174
Avg Supp Capacity Req with Newington on Reserve (MW)	351	354	384	407	464

XVII. Appendix E – PSNH Capacity Position and Purchase Activity

Exhibit E-1: Summary of 2006 Capacity Position and Purchase Activity

	Share of ISO-New England Requirement	PSNH Owned Assets	IPPs	Vermont Yankee	Hydro-Quebec Credits	Demand Response Credits	Supplemental Purchases (MW)
Jan	1,873	1075	121	20	0	0	657
Feb	1,877	1057	127	20	0	0	672
Mar	1,949	1074	127	20	129	0	598
Apr	1,936	1079	126	20	129	0	582
May	1,887	1088	122	20	129	0	528
Jun	1,759	1065	116	20	129	0	429
Jul	1,748	1080	96	21	129	0	422
Aug	1,745	1073	100	21	129	0	423
Sep	1,747	1072	100	21	107	0	447
Oct	1,862	1097	109	21	107	0	529
Nov	1,860	1103	123	21	129	0	485
Dec	2,053	1096	135	21	0	3	799
Total	22,295	12,959	1,401	246	1,117	3	6,570
% of Total		58%	6%	1%	5%	0%	29%

XVIII. Appendix F – Monthly Capacity Balance

Exhibit F-1: PSNH Monthly Capacity Balance during Transition Period Market Rules

	Eligible Supply Resources	Jan-2008	Feb-2008	Mar-2008	Apr-2008	May-2008	Jun-2008	Jul-2008	Aug-2008	Sep-2008	Oct-2008	Nov-2008	Dec-2008
(1)	Generation (SCC)	33,822	33,822	33,822	33,822	33,822	30,784	30,784	30,784	30,784	33,822	33,822	33,822
(2)	Availability Adj't	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893
(3)	Generation (UCAP)	30,188	30,188	30,188	30,188	30,188	27,477	27,477	27,477	27,477	30,188	30,188	30,188
(4)	Load Response Programs	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134
(4)	Other Demand Response (ODR)			165	165	165	165	165	165	165	165	165	165
(5)	Hydro-Quebec and NYPA credits	57	57	1,257	1,257	1,257	1,257	1,257	1,257	1,257	1,257	1,257	57
(6)	Capacity Imports	1,326	1,326	1,839	1,839	1,839	1,839	1,839	1,839	1,839	1,839	1,839	1,326
	Total Supported Capacity	32,705	32,705	34,584	34,584	34,584	31,873	31,873	31,873	31,873	34,584	34,584	32,870
(7)	PSNH Share of ISO-NE Peak (%)	6.41%	6.41%	6.41%	6.41%	6.41%	6.41%	6.41%	6.41%	6.41%	6.41%	6.41%	6.41%
	PSNH Share of Supported Capacity (MW)	2,095	2,095	2,215	2,215	2,215	2,042	2,042	2,042	2,042	2,215	2,215	2,106
(8)	PSNH Resources (SCC) (MW)	1,232	1,232	1,232	1,211	1,211	1,167	1,167	1,167	1,167	1,211	1,221	1,221
(9)	PSNH Resource Availability Adj't	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%
	PSNH Resources (UCAP) (MW)	1,172	1,172	1,172	1,152	1,152	1,109	1,109	1,109	1,109	1,152	1,161	1,161
	Hydro-Quebec Credits (MW)	0	0	129	129	129	129	129	129	129	129	129	0
	Total PSNH Capacity (MW)	1,172	1,172	1,301	1,281	1,281	1,238	1,238	1,238	1,238	1,281	1,290	1,161
	PSNH Capacity Deficiency (MW)	923	923	915	935	935	803	803	803	803	935	925	945

	Eligible Supply Resources	Jan-2009	Feb-2009	Mar-2009	Apr-2009	May-2009	Jun-2009	Jul-2009	Aug-2009	Sep-2009	Oct-2009	Nov-2009	Dec-2009
(1)	Generation (SCC)	33,822	33,822	33,822	33,822	33,822	30,784	30,784	30,784	30,784	33,822	33,822	33,822
(2)	Availability Adj't	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893
(3)	Generation (UCAP)	30,188	30,188	30,188	30,188	30,188	27,477	27,477	27,477	27,477	30,188	30,188	30,188
(4)	Load Response Programs	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134
(4)	Other Demand Response (ODR)	0	0	165	165	165	165	165	165	165	165	165	165
(5)	Hydro-Quebec and NYPA credits	57	57	1,257	1,257	1,257	1,257	1,257	1,257	1,257	1,257	1,257	57
(6)	Capacity Imports	1,326	1,326	1,839	1,839	1,839	1,839	1,839	1,839	1,839	1,839	1,839	1,326
	Total Supported Capacity	32,705	32,705	34,584	34,584	34,584	31,873	31,873	31,873	31,873	34,584	34,584	32,870
(7)	PSNH Share of ISO-NE Peak (%)	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	PSNH Share of Supported Capacity (MW)	2,103	2,103	2,224	2,224	2,224	2,050	2,050	2,050	2,050	2,224	2,224	2,114
(8)	PSNH Resources (SCC) (MW)	1,221	1,221	1,221	1,221	1,221	1,176	1,176	1,176	1,176	1,221	1,221	1,221
(9)	PSNH Resource Availability Adj't	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%	95.1%
	PSNH Resources (UCAP) (MW)	1,161	1,161	1,161	1,161	1,161	1,119	1,119	1,119	1,119	1,161	1,161	1,161
	Hydro-Quebec Credits (MW)	0	0	129	129	129	129	129	129	129	129	129	0
	Total PSNH Capacity (MW)	1,161	1,161	1,290	1,290	1,290	1,248	1,248	1,248	1,248	1,290	1,290	1,161
	PSNH Capacity Deficiency (MW)	942	942	934	934	934	802	802	802	802	934	934	953

	Eligible Supply Resources	Jan-2010	Feb-2010	Mar-2010	Apr-2010	May-2010
(1)	Generation (SCC)	33,822	33,822	33,822	33,822	33,822
(2)	Availability Adj't	0.893	0.893	0.893	0.893	0.893
(3)	Generation (UCAP)	30,188	30,188	30,188	30,188	30,188
(4)	Load Response Programs	1,134	1,134	1,134	1,134	1,134
(4)	Other Demand Response (ODR)	0	0	165	165	165
(5)	Hydro-Quebec and NYPA credits	57	57	1,257	1,257	1,257
(6)	Capacity Imports	1,326	1,326	1,839	1,839	1,839
	Total Supported Capacity	32,705	32,705	34,584	34,584	34,584
(7)	PSNH Share of ISO-NE Peak (%)	6.46%	6.46%	6.46%	6.46%	6.46%
	PSNH Share of Supported Capacity (MW)	2,112	2,112	2,234	2,234	2,234
(8)	PSNH Resources (SCC) (MW)	1,221	1,221	1,221	1,221	1,221
(9)	PSNH Resource Availability Adj't	95.1%	95.1%	95.1%	95.1%	95.1%
	PSNH Resources (UCAP) (MW)	1,161	1,161	1,161	1,161	1,161
	Hydro-Quebec Credits (MW)	0	0	129	129	129
	Total PSNH Capacity (MW)	1,161	1,161	1,290	1,290	1,290
	PSNH Capacity Deficiency (MW)	951	951	944	944	944

Notes:

(1) May 2007 Seasonal Claimed Capability (SCC) for winter and summer ratings
(2) Based on historical data, adjusted for change to weighted forced outage rates
(3) Unforced Capacity ("UCAP") equals SCC times the availability adjustment.
(4) From May 2007 ISO-New England Settlement reports
(5) NYPA 57 MW. Hydro-Quebec 1,200 MW for Mar - Nov and zero in other months.
(6) Based on historical data, adjusted for treatment of Hydro-Quebec credits.
(7) Used historical data (6.36%) and escalated based on ISO-New England forecast of N.H. relative growth rate (see table below)

2008 - 100.7%
2009 - 101.1%
2010 - 101.6%
2011 - 102.0%
2012 - 102.7%

(8) See "SCC" tab
(9) 95.1% is the average availability of the PSNH Resources from May 2007 ISO-New England settlement data

Exhibit F-2: PSNH Monthly Capacity Balance during Forward Capacity Market Rules

	Eligible Supply Resources	Jun-2010	Jul-2010	Aug-2010	Sep-2010	Oct-2010	Nov-2010	Dec-2010
(1)	Installed Capacity Requirement (ICR) (MW)	32,084	32,084	32,084	32,084	32,084	32,084	32,084
(2)	Hydro-Quebec credits	1,200	1,200	1,200	1,200	1,200	1,200	0
	Total Supported Capacity	33,284	33,284	33,284	33,284	33,284	33,284	32,084
(3)	PSNH Share of ISO-NE Peak (%)	6.46%	6.46%	6.46%	6.46%	6.46%	6.46%	6.46%
	PSNH Share of Supported Capacity (MW)	2,150	2,150	2,150	2,150	2,150	2,150	2,072
(4)	PSNH Resources (SCC) (MW)	1,176	1,176	1,176	1,176	1,176	1,176	1,176
	Hydro-Quebec Credits (MW)	129	129	129	129	129	129	0
	Total PSNH Capacity (MW)	1,305	1,305	1,305	1,305	1,305	1,305	1,176
	PSNH Capacity Deficiency (MW)	844	844	844	844	844	844	896

	Eligible Supply Resources	Jan-2011	Feb-2011	Mar-2011	Apr-2011	May-2011	Jun-2011	Jul-2011	Aug-2011	Sep-2011	Oct-2011	Nov-2011	Dec-2011
(1)	Installed Capacity Requirement (ICR) (MW)	32,084	32,084	32,084	32,084	32,084	32,747	32,747	32,747	32,747	32,747	32,747	32,747
(2)	Hydro-Quebec credits	0	0	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	0
	Total Supported Capacity	32,084	32,084	33,284	33,284	33,284	33,947	33,947	33,947	33,947	33,947	33,947	32,747
(3)	PSNH Share of ISO-NE Peak (%)	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%
	PSNH Share of Supported Capacity (MW)	2,080	2,080	2,158	2,158	2,158	2,201	2,201	2,201	2,201	2,201	2,201	2,123
(4)	PSNH Resources (SCC) (MW)	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176
	Hydro-Quebec Credits (MW)	0	0	129	129	129	129	129	129	129	129	129	0
	Total PSNH Capacity (MW)	1,176	1,176	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,176
	PSNH Capacity Deficiency (MW)	904	904	853	853	853	896	896	896	896	896	896	947

	Eligible Supply Resources	Jan-2012	Feb-2012	Mar-2012	Apr-2012	May-2012	Jun-2012	Jul-2012	Aug-2012	Sep-2012	Oct-2012	Nov-2012	Dec-2012
(1)	Installed Capacity Requirement (ICR) (MW)	32,747	32,747	32,747	32,747	32,747	33,343	33,343	33,343	33,343	33,343	33,343	33,343
(2)	Hydro-Quebec credits	0	0	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	0
	Total Supported Capacity	32,747	32,747	33,947	33,947	33,947	34,543	34,543	34,543	34,543	34,543	34,543	33,343
(3)	PSNH Share of ISO-NE Peak (%)	6.53%	6.53%	6.53%	6.53%	6.53%	6.53%	6.53%	6.53%	6.53%	6.53%	6.53%	6.53%
	PSNH Share of Supported Capacity (MW)	2,139	2,139	2,218	2,218	2,218	2,257	2,257	2,257	2,257	2,257	2,257	2,178
(4)	PSNH Resources (SCC) (MW)	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176
	Hydro-Quebec Credits (MW)	0	0	129	129	129	129	129	129	129	129	129	0
	Total PSNH Capacity (MW)	1,176	1,176	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,176
	PSNH Capacity Deficiency (MW)	963	963	912	912	912	951	951	951	951	951	952	1,002

Notes:

(1) Based on ISO-New England 2007 CELT Peak load forecast times and installed reserve margin

(2) Hydro-Quebec 1,200 MW for Mar - Nov and zero in other months.

(3) Used historical data (6.35%) and escalated based on ISO-New England forecast of N.H. relative growth rate (see table below)

2008 - 100.7%
2009 - 101.1%
2010 - 101.6%
2011 - 102.0%
2012 - 102.7%

(4) See "SCC" tab (FCM uses summer rating for all 12 months)

XIX. Appendix G – Integration of Demand Side and Supply Side Options

The following exhibits were used to analyze the supply side projects and select the projects to include in the potential portfolio. Two time frames were used – a five year time horizon to be consistent with the planning horizon throughout the LCIRP and a project life horizon to analyze the long-term benefits of the project.

Net revenue requirements include the estimated cost of the asset and fuel costs, if applicable, reduced for ISO-New England capacity market revenues, REC revenues and tax credits, if applicable. A high and low range was developed to account for higher and lower capital costs.

Market purchase costs consist of the energy market value of the associated output from the generation asset. A range of high and a low market purchase costs were developed using the high and low on-peak and off-peak market prices presented in Exhibit G-13.

The net present value of the annual revenue requirements was calculated and compared to the net present value of the annual market purchase costs. This was done for two time horizons, the 5-year planning horizon and the project life horizon. The project life horizon was used to reflect the project costs over the long-term.

The results of the net present value comparisons are presented in Exhibits G-1 and G-2. A weighted criteria analysis was developed to combine the quantitative revenue requirements analysis with a qualitative analysis of environmental compliance costs, fuel diversity, availability at time of system peak, and price stability. The weighted criteria analysis results are presented in Exhibit G-3. The projects were then ranked according to the weighted criteria results and the final project rankings are presented in Exhibit G-4 and were used to develop the portfolio selected.

Exhibit G-1: Net Revenue Requirements and Market Purchase Comparison, Planning Horizon 2008-2012

Base Case

Option	Project Life (Years)	NPV of Rev Rqmt ($000s)	NPV of Market Purchase ($000s)	Difference
50 MW Biomass Facility	30	$8,441	$15,016	($6,575)
20 MW Distribution Level Peaking Unit	30	$1,285	$409	$877
Solar Photovoltaic – Without BETC	20	$7,693	$1,066	$6,628
Solar Photovoltaic – With BETC	20	($18,814)	$1,066	($19,880)
24 MW Wind Project	20	$4,298	$9,480	($5,182)

Low Case

Option	Project Life (Years)	NPV of Rev Rqmt ($000s)	NPV of Market Purchase ($000s)	Difference
50 MW Biomass Facility	30	$6,393	$15,016	($8,623)
20 MW Distribution Level Peaking Unit	30	$893	$369	$524
Solar Photovoltaic – Without BETC	20	$6,556	$977	$5,579
Solar Photovoltaic – With BETC	20	($19,965)	$977	($20,942)
24 MW Wind Project	20	$2,398	$8,549	($6,151)

High Case

Option	Project Life (Years)	NPV of Rev Rqmt ($000s)	NPV of Market Purchase ($000s)	Difference
50 MW Biomass Facility	30	$10,489	$16,005	($5,516)
20 MW Distribution Level Peaking Unit	30	$1,677	$448	$1,229
Solar Photovoltaic – Without BETC	20	$8,369	$1,155	$7,215
Solar Photovoltaic – With BETC	20	($18,124)	$1,155	($19,279)
24 MW Wind Project	20	$4,593	$10,391	($5,798)

Exhibit G-2: Net Revenue Requirements and Market Purchase Comparison, Project Life Horizon

Base Case

Option	Project Life (Years)	NPV of Rev Rqmt ($000s)	NPV of Market Purchase ($000s)	Difference
50 MW Biomass Facility	30	$10,325	$175,565	($165,240)
20 MW Distribution Level Peaking Unit	30	($2,692)	$1,695	($4,387)
Solar Photovoltaic – Without BETC	20	$47,199	$12,589	$34,610
Solar Photovoltaic – With BETC	20	$1,382	$12,589	($11,207)
24 MW Wind Project	20	($1,635)	$34,602	($36,237)

Low Case

Option	Project Life (Years)	NPV of Rev Rqmt ($000s)	NPV of Market Purchase ($000s)	Difference
50 MW Biomass Facility	30	($4,856)	$164,003	($168,858)
20 MW Distribution Level Peaking Unit	30	($3,793)	$1,571	($5,364)
Solar Photovoltaic – Without BETC	20	$38,026	$11,741	$26,285
Solar Photovoltaic – With BETC	20	($8,179)	$11,741	($19,921)
24 MW Wind Project	20	($4,005)	$32,037	($36,042)

High Case

Option	Project Life (Years)	NPV of Rev Rqmt ($000s)	NPV of Market Purchase ($000s)	Difference
50 MW Biomass Facility	30	$25,505	$187,127	($161,622)
20 MW Distribution Level Peaking Unit	30	($1,592)	$1,819	($3,411)
Solar Photovoltaic – Without BETC	20	$51,892	$13,437	$38,455
Solar Photovoltaic – With BETC	20	$6,462	$13,437	($6,975)
24 MW Wind Project	20	$1,345	$37,167	($35,822)

Exhibit G-3: Weighted Criteria Analysis

		50 MW Biomass Facility		20 MW Distribution Level Peaking Unit		Solar PV – with BETC		Solar PV – without BETC		24 MW Wind Project	
Criteria	**Weight**	**Rating**	**Weighted Rating**	**Rating**	**Weighted Rating**	**Rating**	**Weighted Rating**	**Rating**	**Weighted Rating**	**Rating**	**Weighted Rating**
Revenue Requirements Rank											
(1-High, 2-Medium, 3-Low)	0.30	1.00	0.30	1.00	0.30	1.00	0.30	3.00	0.90	1.00	0.30
Environmental Compliance Costs											
(1-Low, 2-Medium, 3-High)	0.20	1.00	0.20	2.00	0.40	1.00	0.20	1.00	0.20	1.00	0.20
Fuel Diversity											
(1-High, 2-Medium, 3-Low)	0.15	1.00	0.15	2.00	0.30	1.00	0.15	1.00	0.15	1.00	0.15
Availability at Time of System Peak											
(1-High, 2-Medium, 3-Low)	0.15	1.00	0.15	1.00	0.15	2.00	0.30	2.00	0.30	2.00	0.30
Promotes Price Stability											
(1-Stable, 2-Medium, 3-Volatile)	0.20	2.00	0.40	2.00	0.40	1.00	0.20	1.00	0.20	1.00	0.20
Total	1.00		1.20		1.55		1.15		1.75		1.15

Exhibit G-4: Final Project Ranking

Project	Weighted Score	Rank
50 MW Biomass Facility	1.20	2
20-25 MW Distribution Level Peaking Units	1.55	3
Solar Photovoltaic - with BETC	1.15	1
Solar Photovoltaic - without BETC	1.75	4
24 MW Wind Project	1.15	1

A. Avoided Cost Methodology and Forecast

Comparing demand-side and supply-side resource options in the context of LCIRP requires a methodology for measuring the avoided costs (i.e., savings) associated with not having to purchase additional supplemental power or building new generation capacity. The following provides a description of the avoided cost methodology and the resulting avoided cost forecast for DSM and supply-side resource evaluation purposes.

Avoided costs will vary depending on whether demand growth is met with new generation capacity or additional supplemental power purchases. In the former case, the avoided costs include deferred capital investments and deferred operating costs. Deferred operating costs include, among other things, fuel expenses, labor costs, costs related to mercury abatement, and reductions in allowance expenses related to SO_2 and NOx emissions. For the purpose of this filing, PSNH assumes that DSM measures will avoid a similar quantity of supplemental power purchases. As such, the "avoided cost forecast" results herein can be regarded as a forecast of the cost of supplemental energy and capacity purchases. It must be stressed that this forecast has been developed solely for the purpose of compliance with the LCIRP filing requirement. PSNH considers that each unique resource opportunity requires a specific economic review and that no single projection of uncertain market conditions is universally applicable.

A.1.1. Energy Forecast Alternatives

There are two primary approaches available for developing a forecast of energy prices: a market-based approach and a fundamental approach. A market-based forecast uses available data regarding the current cost to procure energy for delivery in the future, i.e. the price at which a willing buyer and a willing seller might agree to transact energy. For example, on June 1, 2007 a contract might be executed under which Party A would deliver energy to Party B during the month of January 2008 for a fixed-price of $100 per MWh. Another way to express this information is to say that on June 1, 2007 the forward market price for January 2008 was $100 per MWh. Forward market prices fluctuate constantly and theoretically reflect the combined "wisdom" of all market participants regarding future supply and demand fundamentals as well as other non-quantifiable factors such as near-term anticipated weather (colder or warmer than normal winter), potential supply disruptions (hurricanes), nascent geopolitical instability, the price of oil and natural gas, etc. Only a week later, on June 8, 2007, the same product mentioned above (energy delivered in January 2008) might have a forward price of $105 per MWh. Forward price information is available from a number of fee-based market data services or can be obtained from commodity brokers. PSNH typically utilizes information provided directly from energy and commodity brokers.

An alternative approach to energy forecasting is to model the fundamental drivers of electricity supply, demand, and marginal costs. This might involve a production cost simulation in which a variety of inputs are required to mathematically quantify the marginal production cost of a given region (e.g., ISO-New England). The model inputs would include: hourly load forecast, generation asset operating characteristics, and forecast fuel prices. In a deregulated market such as ISO-New England, in which most all generation resources are owned and operated by unregulated entities, accurate information about unit characteristics and fuel costs are proprietary. In addition, unregulated generation companies are not required to use strictly cost-based dispatch prices, i.e. there is some flexibility to offer energy to ISO-New England at prices that are greater or less than short-run marginal costs. For this and other reasons, PSNH no longer maintains a detailed production cost simulation model. Instead, PSNH contracts with a consultant (Energy Ventures Associates or "EVA") to provide a quarterly long-term forecast of commodity market prices which PSNH converts into forecasted energy prices.

The market-based and fundamental forecasts may produce prices that differ significantly. In recent history, the norm has been that the forward market-based prices exceed the fundamental prices. The reason for these differences can be debated, but a basic theory is that the current forward market prices incorporate a degree of risk premium based on near-term supply and demand concerns, such as hurricanes, extreme weather impact on natural gas inventories, etc. Fundamental forecasts, on the other hand, are more reflective of long run expectations regarding commodity market infrastructure. Fundamental forecasts typically are performed under "reference" or "normal" assumptions (e.g., weather, demand growth, new generation construction, etc.), and do not attempt to model extreme short-term events such as large supply disruptions, political instability, etc. Regardless, in the short-term, an interested buyer of a forward energy product must be resigned to the fact that willing sellers will utilize current broker quotes as the benchmark price. To continue with the example above, on June 8, 2007, a willing buyer can either agree to pay $105/MWh for energy in January 2008, or the buyer can elect to remain exposed to their purchase need and speculate that hourly prices in January 2008 resemble the fundamental forecast prices. In reality, hourly prices in January 2008 may be much higher or lower than expectations. The buyer must be willing to accept this uncertainty.

For purposes of this LCIRP, PSNH has developed a forecasting approach that utilizes a blend of current forward price information (e.g., broker quotes) and the most recent quarterly EVA report. By doing so, the set of future prices are representative of energy that may be procured through a variety of practices. For example, PSNH utilizes bilateral purchases executed months prior to delivery to serve a portion of the Energy Service requirement. These bilateral purchase contracts will typically be "market-based" (i.e., the price will be reflective of the current broker quotes on the day the contracts are executed). PSNH also procures a portion of their needs via the shorter-term markets (e.g., weekly, daily, and hourly purchases from ISO-New England). In a long-range plan, these procurement methods may be more appropriately forecasted using the fundamental numbers.

A.1.2. Energy Price Forecast Methodology and Results

The energy forecast results are provided in the following exhibits. Exhibit G-7 provides the forward energy market prices used in the process. These prices were taken from broker information on August 27, 2007.

As can be seen on Exhibit G-7, the broker information contains monthly on-peak and off-peak prices through August 2008 and a set of annual prices for years 2008 through 2011. This report uses the midpoint between the listed "bid" and "offer" price as representative of the current market value.

Exhibit G-7: Forward Energy Market Prices on August 27, 2007

Term	NEPOOL On-Peak 5x16 Bid	NEPOOL On-Peak 5x16 Offer	NEPOOL Off-Peak 5x8, 2x24 Bid	NEPOOL Off-Peak 5x8, 2x24 Offer
Sept-2007	$ 58.25	$ 59.00	$ 44.75	$ 45.25
Oct-2007	$ 60.35	$ 61.00	$ 46.25	$ 46.75
Nov-2007	$ 67.65	$ 68.00	$ 51.75	$ 52.00
Dec-2007	$ 76.00	$ 76.50	$ 59.00	$ 59.50
Q4-2007	$ 68.00	$ 68.50	$ 52.50	$ 53.00
Jan-Feb 2008	$ 91.00	$ 91.10	$ 72.50	$ 73.50
Mar-2008	$ 81.50	$ 82.00	$ 64.00	$ 64.50
Apr-2008	$ 74.50	$ 75.00	$ 57.00	$ 57.75
May-2008	$ 72.75	$ 73.00	$ 54.50	$ 55.50
June-2008	$ 76.25	$ 77.00	$ 55.50	$ 56.50
Summer-2008	$ 88.65	$ 89.00	$ 60.00	$ 60.50
Sept-2008	$ 76.00	$ 76.25	$ 56.50	$ 57.50
Q4-2008	$ 81.00	$ 81.75	$ 62.25	$ 63.00
Calendar-2008	$ 82.00	$ 82.30	$ 61.75	$ 62.25
Calendar-2009	$ 85.00	$ 85.30	$ 63.60	$ 64.00
Calendar-2010	$ 82.75	$ 83.25	$ 61.75	$ 62.25
Calendar-2011	$ 81.00	$ 81.75	$ 60.00	$ 60.75

Exhibit G-8 shows the movement of forward prices prior to and subsequent to June 13, 2007 and is provided to assist the reader in understanding how market-based price forecasts are a constantly moving target.

Exhibit G-8: Forward Price History for 2008 On-Peak Energy

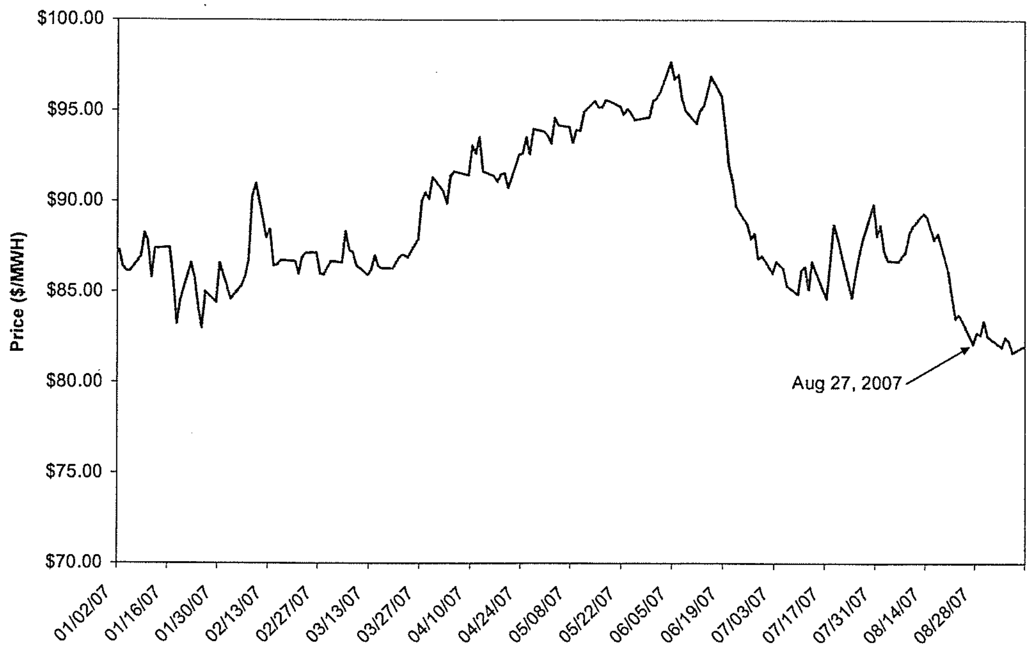


Exhibit G-9 provides the annual average forward market prices for NYMEX Natural Gas contracts. These NYMEX contracts prices are for future delivery of a standard quantity of gas to the Henry Hub (Louisiana) location. NYMEX basis prices for Transco Zone 6-New York are also provided. These basis prices are the incremental cost to deliver natural gas from the Henry Hub to an alternate location, in this case the Transcontinental Gas Pipeline Company location in New York (known as Zone 6-NY). Transco Zone 6-NY is outside of ISO-New England and, as such, is not a perfect representation of the future price of gas to a ISO-New England generator, but it is the only nearby location traded at NYMEX and generally correlates with basis pricing into New England.

Exhibit G-9: NYMEX Natural Gas Contract Data from August 27, 2007

Delivery Year	Henry Hub ($/mmbtu)	Transco Z6 Basis ($/mmbtu)	Delivered Price ($/mmbtu)
2008	$7.72	$1.38	$9.11
2009	$8.06	$1.49	$9.55
2010	$7.84	$1.50	$9.35
2011	$7.61	$1.46	$9.07
2012	$7.41	$1.42	$8.84

Note: on August 27, 2007, Transco Zone 6 basis prices were only reported through 2009. The data in Exhibit IV-17 assumes that, for 2010 through 2012, the change in basis price will be proportional to the change in Henry Hub gas price.

Exhibit G-10 provides the August 2007 EVA forecast for natural gas during the planning period. Natural Gas prices are provided for both the Henry Hub location and a set of higher prices for delivery to Connecticut. The Connecticut delivered prices are used in this LCIRP to forecast the fuel expense that would apply to a typical gas-fired generation station within the ISO-New England region.

Exhibit G-10: August 2007 EVA Forecast of Natural Gas Price (nominal dollars)

Delivery Year	Henry Hub ($/mmbtu)	Connecticut Basis ($/mmbtu)	Delivered Price ($/mmbtu)
2008	$6.75	$0.60	$7.35
2009	$6.56	$0.61	$7.17
2010	$6.69	$0.61	$7.30
2011	$6.90	$0.62	$7.52
2012	$7.11	$0.63	$7.74

A key step in developing the energy forecast is to examine the relationship between market-based forward energy prices (i.e., the broker data from Exhibit G-7) and market-based forward gas prices (i.e., the NYMEX data from Exhibit G-9). This relationship defines an "indicative heat rate" that can be viewed as the average efficiency with which the marginal generator in ISO-New England converts natural gas into energy. The concept of indicative heat rate does not require a conviction that a natural gas-fired generator will determine the marginal price in ISO-New England 100 percent of the time. It merely is a numerical representation of the relationship between gas and energy that forward market participants have established. Exhibit G-11 includes the indicative heat rates derived from 2008 through 2011 market prices for both On-Peak and Off-peak energy. Also shown in Exhibit G-11 is the resulting forward market price for energy in 2012 that can be derived by multiplying the 2012 NYMEX gas data by the 2011 indicative heat rate. In this manner, information that is not available in Exhibit G-7 (namely, 2012 energy prices) can be developed.

Exhibit G-11: Forward Market Indicative Heat Rate Results

Year	NYMEX Gas ($/mmbtu)	On-Peak Heat Rate (mmbtu/MWh)	Off-Peak Heat Rate (mmbtu/MWh)	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)
2008	$9.11	9.02	6.81	$82.15	$62.00
2009	$9.55	8.91	6.68	$85.15	$63.80
2010	$9.35	8.88	6.63	$83.00	$62.00
2011	$9.07	8.97	6.65	$81.38	$60.38
2012	$8.84	8.97	6.65	$79.24	$58.79

Note: 2012 Energy Prices are derived from NYMEX Gas using the 2011 Heat Rates

The heat rates developed in Exhibit G-11 can also be used to convert the EVA natural gas forecast into a set of fundamental-based energy prices for 2008 through 2012. These values are provided in Exhibit G-12.

Exhibit G-12: Fundamental-Based Energy Price Forecast using Indicative Heat Rates

Year	EVA Gas ($/mmbtu)	On-Peak Heat Rate (mmbtu/MWh)	Off-Peak Heat Rate (mmbtu/MWh)	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)
2008	$7.35	9.02	6.81	$66.32	$50.05
2009	$7.17	8.91	6.68	$63.89	$47.87
2010	$7.30	8.88	6.63	$64.82	$48.42
2011	$7.52	8.97	6.65	$67.46	$50.05
2012	$7.74	8.97	6.65	$69.45	$51.53

Exhibit G-13 summarizes three sets of energy prices:

1) Prices based on forward market data
2) Prices based on the EVA fundamental forecast model
3) A combined set of prices which consist of an equal weighing (50%-50%) of the two prior pricing sets

For purposes of this LCIRP, the three price forecasts will be hereafter referred to as "High", "Low" and "Reference". Energy prices outside of the 5 year planning horizon were escalated using a forecasted CPI growth rate. For purposes of revenue requirements analysis, the Reference price forecast was used.

Exhibit G-13: Summary of Energy Price Forecast Results

Year	On Peak Energy ($/MWh)				Off Peak Energy ($/MWh)		
	Market Based ("High")	50-50 Weighted ("Reference")	Fundamental Based ("Low")		Market Based ("High")	50-50 Weighted ("Reference")	Fundamental Based ("Low")
2008	$82.15	$74.23	$66.32		$62.00	$56.03	$50.05
2009	$85.15	$74.52	$63.89		$63.80	$55.84	$47.87
2010	$83.00	$73.91	$64.82		$62.00	$55.21	$48.42
2011	$81.38	$74.42	$67.46		$60.38	$55.21	$50.05
2012	$79.24	$74.35	$69.45		$58.79	$55.16	$51.53
2013	$80.91	$75.92	$70.92		$60.03	$56.32	$52.62
2014	$82.60	$77.50	$72.40		$61.29	$57.50	$53.71
2015	$84.40	$79.19	$73.97		$62.62	$58.75	$54.88
2016	$86.30	$80.97	$75.64		$64.03	$60.07	$56.12
2017	$88.33	$82.87	$77.41		$65.53	$61.48	$57.43
2018	$90.40	$84.81	$79.23		$67.07	$62.92	$58.78
2019	$92.50	$86.78	$81.07		$68.63	$64.39	$60.15
2020	$94.62	$88.78	$82.93		$70.20	$65.87	$61.53
2021	$96.75	$90.77	$84.79		$71.78	$67.35	$62.91
2022	$98.92	$92.80	$86.69		$73.39	$68.85	$64.32
2023	$101.13	$94.88	$88.63		$75.03	$70.40	$65.76
2024	$103.39	$97.00	$90.62		$76.71	$71.97	$67.23
2025	$105.70	$99.17	$92.64		$78.42	$73.58	$68.73
2026	$108.06	$101.38	$94.70		$80.17	$75.22	$70.26
2027	$110.47	$103.64	$96.82		$81.96	$76.90	$71.83
2028	$112.93	$105.96	$98.98		$83.79	$78.61	$73.44
2029	$115.45	$108.32	$101.19		$85.66	$80.37	$75.07
2030	$118.03	$110.74	$103.44		$87.57	$82.16	$76.75
2031	$120.66	$113.21	$105.75		$89.52	$83.99	$78.46
2032	$123.35	$115.73	$108.11		$91.52	$85.87	$80.21
2033	$126.11	$118.31	$110.52		$93.56	$87.78	$82.00
2034	$128.92	$120.95	$112.99		$95.65	$89.74	$83.83
2035	$131.79	$123.65	$115.51		$97.78	$91.74	$85.70
2036	$134.73	$126.41	$118.09		$99.96	$93.79	$87.61
2037	$137.74	$129.23	$120.72		$102.19	$95.88	$89.57
2038	$140.81	$132.11	$123.41		$104.47	$98.02	$91.56
2039	$143.95	$135.06	$126.17		$106.81	$100.21	$93.61
2040	$147.17	$138.07	$128.98		$109.19	$102.44	$95.70
2041	$150.45	$141.15	$131.86		$111.62	$104.73	$97.83

A.1.3. Capacity Price Forecast Methodology and Results

On February 15, 2007, ISO-New England filed with FERC a set of market rule revisions designed to implement the Forward Capacity Market Settlement Agreement. This agreement, reached by participant in March 2006 and approved by FERC on June 16, 2006, contained the framework for a new, forward auction-based method of acquiring capacity. The first forward capacity auction ("FCA") is scheduled to occur in February 2008 and will establish FCM clearing prices effective June 1, 2010 through May 30, 2011. Subsequent auctions will establish capacity prices thereafter. The agreement also detailed a Transition Period Capacity Market, designed to provide a source of compensation to capacity resources until the commencement of FCM. The Transition Period began on December 1, 2006 and will terminate on May 30, 2010.

During the Transition Period, qualified capacity resources will receive compensation according to the rate schedule in Exhibit G-14. These payments will be paid per MW of "unforced" capacity, i.e. a qualified generator with a claimed capability of 100 MW and an average forced outage rate of 10 percent, will be paid based on 90 MW of unforced capacity.

Exhibit G-14: Transition Period Capacity Market Prices

Period	Price ($/MW-Month)
Dec 2006 – May 2008	$3,050
June 2008 – May 2009	$3,750
June 2009 – May 2010	$4,010

Following the Transition Period, capacity compensation will be determined via periodic auctions into which new sources of capacity can offer a price. If the offer is accepted (i.e., clears in the auction) the suppliers receives an obligation to provide MWs in a future period. The first auction is scheduled for February 2008. PSNH will not speculate as to the outcome of this auction. For purposes of the LCIRP, PSNH assumes the first FCA clearing price will equal the benchmark "Cost of New Entry" ("CONE"). The concept of CONE is an important benchmark used for several pricing and market monitoring purposes through the FCM market rules. For the first FCA, the market rules have predetermined a CONE equal to $7,500 per MW-month. This value is based on an ISO-New England analysis of the levelized cost of new peaking capacity in the ISO-New England region.

The forecasted capacity prices are summarized in Exhibit G-15. The annual prices shown reflect the Transition Period price schedule from Exhibit G-13 and the $7,500 per MW-month CONE starting June 2010. For this LCIRP, the initial CONE price is assumed to escalate with inflation at 2.1 percent in subsequent auctions. Capacity prices outside of the 5 year planning horizon were escalated using a forecasted CPI growth rate.

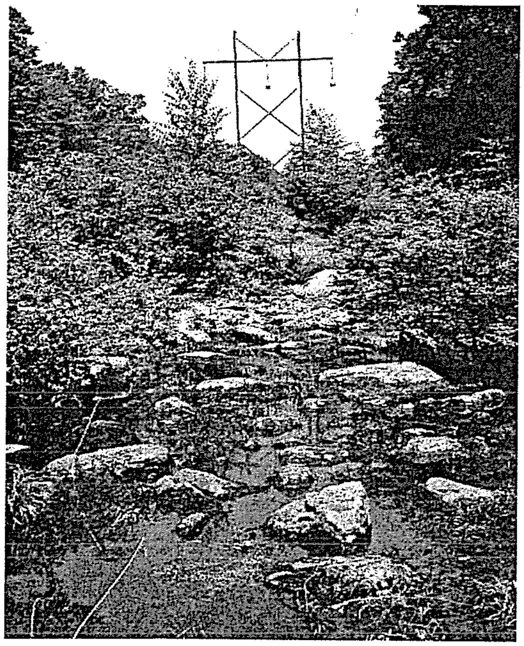
Exhibit G-15: Summary of Capacity Price Forecast Results

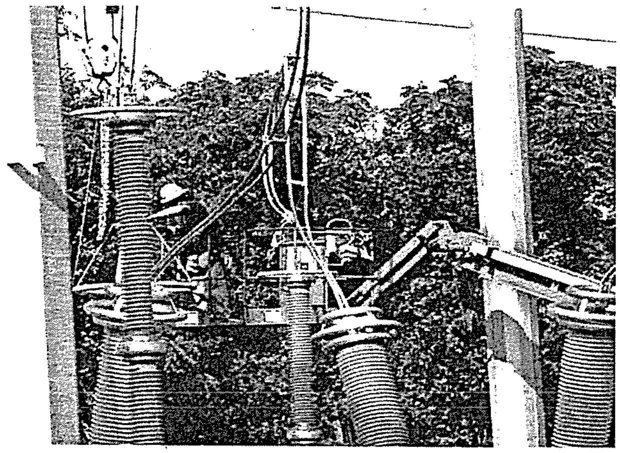
Year	Capacity Price ($/kW-Month)
2008	$3.46
2009	$3.95
2010	$6.08
2011	$7.59
2012	$7.75
2013	$7.91
2014	$8.08
2015	$8.25
2016	$8.44
2017	$8.64
2018	$8.84
2019	$9.05
2020	$9.25
2021	$9.46
2022	$9.67
2023	$9.89
2024	$10.11
2025	$10.34
2026	$10.57
2027	$10.80
2028	$11.04
2029	$11.29
2030	$11.54
2031	$11.80
2032	$12.06
2033	$12.33
2034	$12.61
2035	$12.89
2036	$13.18
2037	$13.47
2038	$13.77
2039	$14.08
2040	$14.39
2041	$14.71

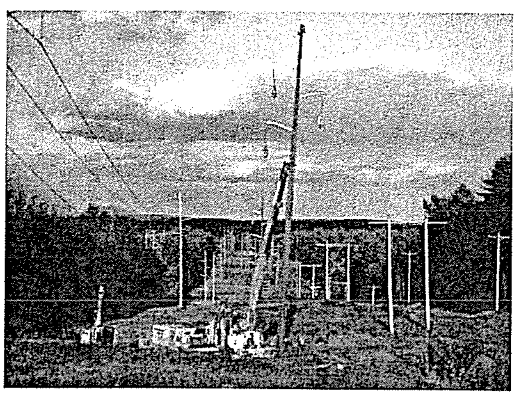
XX. Appendix H – PSNH's Transmission Plan

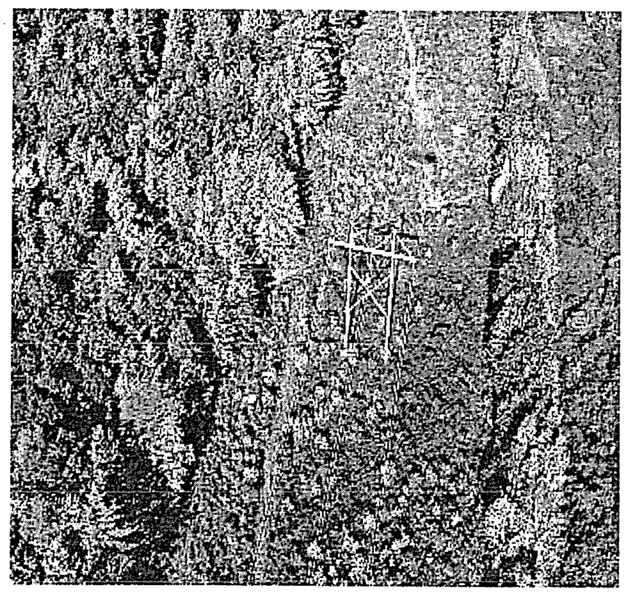
Attached is PSNH's Transmission Plan. PSNH's Transmission Plan is filed on a biennial basis to the New Hampshire Public Utilities Commission. The last such filing was made on June 30, 2005. PSNH's Transmission Plan was updated for this LCIRP filing and is submitted as Appendix H.

PSNH Transmission Plan









Public Service of New Hampshire

September 30, 2007

Public Service of New Hampshire

The Northeast Utilities System

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EXECUTIVE SUMMARY

A Continuing Responsibility to Ensure Electric Delivery System Reliability

Public Service Company of New Hampshire ("PSNH" or "the Company") is an electric utility that serves more than four-hundred and seventy-five thousand homes and businesses in New Hampshire. One of PSNH's primary responsibilities is to provide safe and reliable electric delivery service to our customers. In order to ensure reliable electric service, PSNH monitors system loads and works within the Independent System Operator New England, Inc. ("ISO-NE") transmission planning process to plan system modifications and new facilities needed to reliably meet its load serving requirements.

PSNH is filing its 2007 Transmission Plan pursuant to RSA 378:38, which requires each electric utility to file a transmission plan with the New Hampshire Public Utilities Commission ("NHPUC") at least biennially.

This report focuses on the high voltage electric transmission system (PSNH transmission facilities at or above 115,000 volts are considered "high voltage"). Transmission systems transport power from generation sites to the local "neighborhood" systems that distribute power to residences, businesses, and communities. PSNH's transmission system serves an important role in ensuring electric service reliability, and it must be robust and flexible enough to accommodate an ever-changing generation marketplace. This transmission system also has a critical supporting role in the economic growth of New Hampshire and the New England region by providing access to diverse, competitively-priced, and environmentally beneficial electrical energy resources. It is the crucial link between power generation and New Hampshire consumers. PSNH is investing in New Hampshire's future by strengthening the regional transmission infrastructure.

New Hampshire Faces Challenges on Three Fronts

PSNH foresees that electric service reliability is facing challenges along three fronts over the next ten years:

- Meeting higher demands for electricity;
- Connecting new generation resources to the electric grid; and
- Complying with mandatory reliability standards

Highlights of the challenges for each of these follow.

Meeting higher demands for electricity

Challenges

- Peak demand for electricity in New Hampshire continues to grow at a fast pace.
- Despite investing in efficiency and conservation measures over the last 10 years, New Hampshire's peak load has grown by over 30 percent since 1996.
- In 2006, New Hampshire set a record for peak electric demand -- approximately 2,450 Megawatts ("MW") as reported by ISO-NE.
- ISO-NE's 2006 Regional System Plan ("RSP"), predicts New Hampshire will have a summer compound annual growth rate ("CAGR") of 2.7% over the next 10 years, which is the highest among all New England states.

Plans

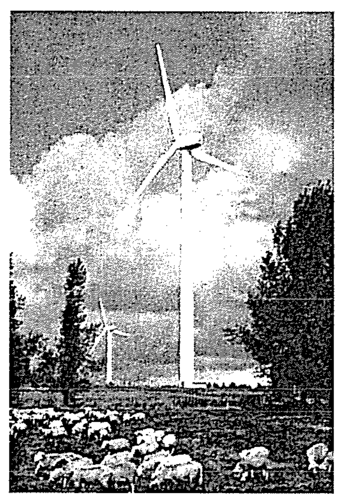
- Continue to closely monitor customer demands for electricity.
- Work with ISO-NE to update demand forecasts used for transmission planning purposes.
- Revise transmission plans to incorporate changes in demand forecasts.

	Summer-Peak Loads (MW) 90/10		
State	**2006**	**2015**	**CAGR**
New England	28,785	34,065	1.9%
Massachusetts	13,290	15,580	1.8%
Connecticut	7,730	9,120	1.9%
New Hampshire	**2,575**	**3,270**	**2.7%**
Maine	2,115	2,540	2.1%
Rhode Island	1,970	2,275	1.6%
Vermont	1,105	1,290	1.7%

Connecting new generation resources to the electric grid

Challenges

- The ISO-NE generation queue has over 1,000 MW of new resource interconnection requests in New Hampshire.
- Renewable resources are not always sited close to significant load centers, so an upgraded transmission system will be needed to move this power to the load.
- The prospect of transporting renewable energy from northern New Hampshire is particularly promising.



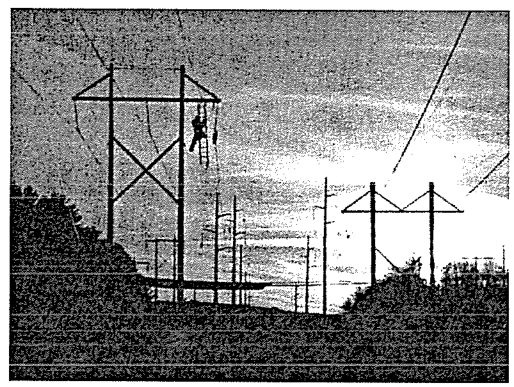
Plans

- Work with the state of New Hampshire and ISO-NE to identify the needs and interconnection solutions for new renewable and other generation resources. Support the development of a New Hampshire Public Utilities Commission report to the New Hampshire Legislature to meet the requirements Senate Bill 140.
- Perform system impact studies for new resource interconnections in accordance with the interconnection requirements and processes of the Federal Energy Regulatory Commission ("FERC") approved ISO-NE Transmission, Markets and Services Tariff ("ISO-NE Tariff").
- Plan, develop and construct transmission facilities to interconnect and efficiently deliver new generation resources to the New England market.

Complying with mandatory reliability standards

Challenges

- Power flows instantaneously across the system without regard to state boundaries. The system is connected throughout New England and with New York and Canada. This broader base for the power grid gives each state an added measure of reliability and system security.



- Mandatory reliability standards are established by the North American Electric Reliability Council ("NERC") and approved by FERC as a result of the Energy Policy Act of 2005.
- The new mandatory reliability standards became effective on June 18, 2007. FERC can impose severe financial penalties of up to $1 million per day for each non-compliance occurrence.
- ISO-NE has responsibility to meet reliability standards set by NERC and the Northeast Power Coordination Council ("NPCC") for planning and operating the New England grid. PSNH's planning and operations must also meet federal reliability standards and the reliability requirements of ISO-NE.

Plans

Complete transmission facilities which are under construction, such as:

- The addition of a third 345/115-kV autotransformer at the Scobie Substation ($20 million).
- The addition of a 345/115-kV autotransformer at the new Fitzwilliam Substation and its associated 115-kV transmission line upgrades ($60 million).
- The installation of a 115-kV phase shifting transformer at the Saco Valley Substation and associated facilities ($30 million).
- The installation of a new 115-kV transmission line between the Scobie and Hudson Substations ($10 million).

Complete the planning for new transmission facilities, such as:

- The addition of a new 345/115-kV substation in the vicinity of the Newington Substation.
- The addition of a second 345/115-kV autotransformer at the Deerfield Substation.
- The addition of a fourth 345/115-kV autotransformer at the Scobie Substation.
- The upgrade of the 115-kV L175 transmission line between Deerfield and Madbury.

Continue to operate and maintain the transmission system in accordance with NERC, NPCC and ISO-NE requirements.

Chapter 1: INTRODUCTION

1.1 Report Overview

In this report, PSNH presents and discusses the following:

- The forecast of peak demands for electricity.
- Regional transmission planning process under ISO-NE.
- National and regional transmission reliability standards.
- Load areas in New Hampshire currently under evaluation.

PSNH presents tables listing proposed modifications and new facilities to its transmission system through the planning period.

1.2 Planning Principles

The key principle of transmission planning is to have a known and measurable plan to reliably meet future peak demands for electricity. New investments in transmission facilities ensure the continuance of a reliable and dependable electric system to support the expansion of the New Hampshire economy. Transmission plans must also recognize the impact the facilities have on the communities served by PSNH.

Planned transmission facilities generally serve at least one of the following purposes:

1) To reliably serve customers' peak demands for electricity.

2) To maintain system reliability under varying generator dispatch scenarios.

3) Interconnect new generation resources.

4) To provide transmission transfer capability on a regional basis.

5) To resolve system reliability and safety concerns of high short-circuit currents.

The PSNH and ISO-NE planning processes employ similar methodologies with respect to the identification of system needs, the consideration and evaluation of multiple alternatives and the final development of a recommended plan. PSNH, through extensive coordination efforts with ISO-NE, effectively integrates its planning functions with other regional entities including neighboring electric systems. Therefore, PSNH's planning process is fundamentally consistent with the ISO-NE regional planning process. This coordination continuously reflects the changing environment with respect to transmission service, in order to ensure efficient and reliable transfer of electric energy that serves the needs of the local delivery systems while enhancing the capabilities of the transmission grid on a regional basis.

The decision-making process for new transmission facilities must balance the needs of a diverse group of stakeholders, including customers, the community and regulators. The planning process employs four governing "Planning Principles." Transmission plans must:

- provide for reliable electricity delivery to customers in accordance with mandatory reliability standards;
- take into account the evolving competitive generation marketplace;

- encompass existing and evolving technologies that can advance transmission expansion plans at a reasonable cost; and
- recognize the impact of a transmission plan on a community in an environmentally sensitive manner.

The decision-making process for comparing alternatives takes into consideration several factors. These include:

1. Compliance with Mandatory Reliability Standards.
   In June 2007, FERC made effective mandatory reliability standards that now have financial penalties for the users, owners or operators of the bulk-power system who fail to comply with the standards. PSNH's planning activities seek to ensure all planned projects will meet these new standards.

2. Cost-Effectiveness
   Planned project capital costs form the basis for the cost-effectiveness test that is a primary consideration used in the decision-making process. Costs for all practical alternative scenarios are computed and compared against each other. PSNH seeks to ensure that cost-effectiveness analyses include the best available capital cost data.

3. Environmental Impacts
   Environmental impacts in accordance with federal and state environmental regulations are considered in the planning process. PSNH includes in its analyses the direct costs associated with complying with known and probable environmental regulations.

4. System Efficiencies
   System efficiencies can be achieved through the planning process when considering ease of operations, reduction of system losses, promptness of customer load restoration, and overall efficient electric utility management of the transmission system.

5. Service Requirements
   Transmission customers who have requested service across PSNH's system will be included in the planning process to ensure that the desired quantity of service is provided. Historically, transmission customers have been provided service and enjoyed equal and open access to PSNH's transmission system in accordance with FERC requirements. The requests for service will continue to be modeled in system planning studies.

Attachment I contains a general description and flow chart of the transmission planning process.

The justification for new transmission facilities is based on the need for system reinforcements to maintain system security in accordance with mandatory reliability standards. They are supported with a quantitative comparison of the future reliability benefits and the cost of the facility versus all other available transmission alternatives. PSNH strives to balance the need for additional system capability with the economics of the new facilities targeted to meet future customer demands for electricity.

Chapter 2: LOAD FORECAST AND GENERATION SUPPLY

Chapter Highlights

- The PSNH system continues to reach new peak demands for electricity.
- PSNH uses the ISO-NE's load forecast for transmission planning purposes.
- New generation resources are seeking interconnection to the New Hampshire electric system.

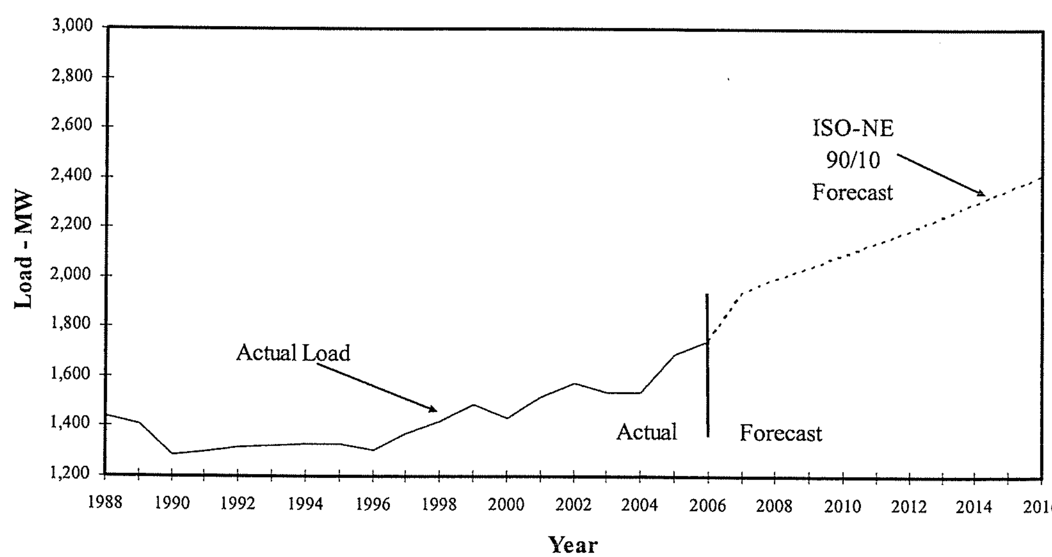
2.1 ISO-NE Load Forecast

ISO-NE in conjunction with PSNH and other transmission owners develops annual forecasts of peak loads for each New England state. The load data is contained in the annual filing of the ISO-NE Forecast Report of Capacity, Energy, Loads and Transmission ("CELT") report and in the ISO-NE RSP.

ISO-NE and transmission owners use a planning approach which provides more certainty of ensuring a transmission system capable of providing reliable electric service even under the most severe weather conditions.

New England utilities use a 90/10 demand forecast developed by ISO-NE for transmission planning purposes. This forecast assumes that the actual peak load has a 10% chance of exceeding the 90/10 forecasted load level and a 90% chance of falling short of the 90/10 forecasted load level. Chart 2-1 contains the ISO-NE 2007 CELT report peak-demand forecast data for PSNH that is used as input in New England power flow models.

Chart 2-1
ISO-NE Demand Forecast for PSNH
Summer Peak



2.2 Generation Supply

The availability of generation capabilities for transmission planning purposes is obtained from the most recent issue of the ISO-NE CELT report, RSP06 and from the ISO-NE generation interconnection queue. Generation additions and known retirements are analyzed to determine their impact on transmission system reliability. Various generation dispatch scenarios are used as input into power flow models of PSNH's electrical system. Table 2-2 contains a summary listing of generating facilities listed in the ISO-NE CELT report for New Hampshire.

Table 2-2
ISO-NE CELT Report
Existing New Hampshire Generation Data

Unit Name	City or Town	Summer MW
Seabrook	Seabrook	1242
Granite Ridge	Londonderry	640
Newington Energy	Newington	506
Newington	Newington	400
Merrimack 2	Bow	320
Moore	Monroe	191
Comerford	Monroe	161
Merrimack 1	Bow	112
Schiller 4	Portsmouth	48
Schiller 5	Portsmouth	37
Schiller 6	Portsmouth	48
Tamworth	Tamworth	21
Schiller Jet	Portsmouth	17
White Lake Jet	Tamworth	17
Merrimack Jet	Bow	17
Merrimack Jet	Bow	17
Amoskeag	Manchester	17
Bethlehem	Bethlehem	16
Bridgewater	Bridgewater	16
Hemphill	Springfield	14
Lost Nation	Northumberland	14
Whitefield	Whitefield	14
Garvins/Hooksett	Hooksett	14
SES Concord	Concord	12
Smith	Berlin	12
Units < 10 MW Each	Various	96
Total All Units		**4019**

Chapter 3: TRANSMISSION PLANNING

Chapter Highlights

- ISO-NE is responsible for developing and maintaining a process to develop a regional system plan that identifies transmission system infrastructure needs.
- Transmission systems serve a key role in facilitating a competitive generation marketplace.
- PSNH transmission facilities must be designed, operated and maintained in accordance with the reliability standards set by FERC, NERC, NPCC and ISO-NE.

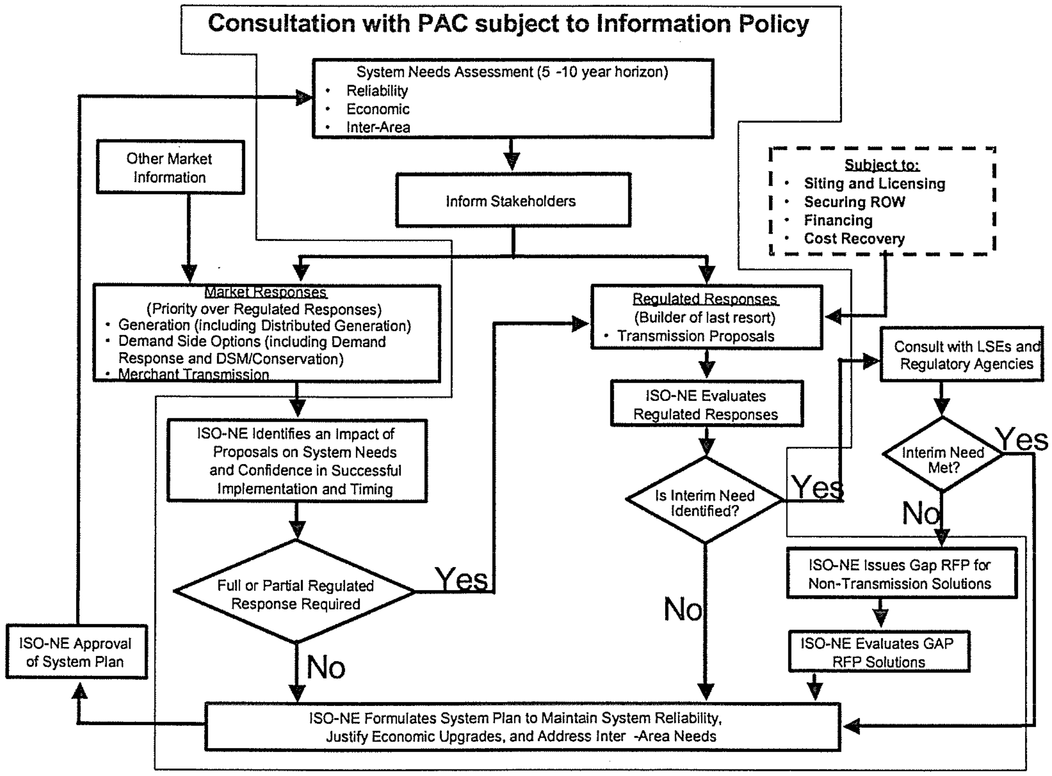
3.1 Transmission Planning In A Restructured Electric Market

The introduction of competition into the previously integrated electric industry altered the focus of transmission system planning. Local transmission systems built in the past to serve customer load from generation within a limited geographic area are now expected to serve the same customer load from remote generation. Transmission systems must now be able to operate reliably with less reliance on local generation.

In 2001, FERC required the New England Power Pool ("NEPOOL") to cede responsibility for the system planning process of the bulk power system to ISO-NE. As the regional transmission organization ("RTO"), ISO-NE is now responsible for transmission planning of the bulk power system in New England. Pursuant to the regional system planning process in the ISO-NE Tariff, ISO-NE determines system reliability and market efficiency needs and approves regulated transmission plans.

Diagram 3-1 is ISO-NE's current regional system planning process under the RTO structure. The diagram shows a process in which ISO-NE identifies, through a system needs assessment process, New England reliability problems. ISO-NE solicits alternative solutions to these reliability problems. Finally, ISO-NE will determine which transmission projects will address system reliability and economic efficiency needs that are not resolved by market responses.

Diagram 3-1



PAC = Planning Advisory Committee
LSE = Load Serving Entity

Through this planning process ISO-NE is responsible for developing and maintaining a transmission plan on a coordinated regional basis. The annual RSP that is approved by the ISO-NE's Board of Directors encourages the development of generation and transmission facilities that ensure the reliability of the New England bulk power system, taking into account load growth and known resource changes.

In addition to assessing the amount of resources needed by the overall system and individual sub areas of the system, the planning process assesses the types of resources that can satisfy these needs and any critical time constraints for addressing them. Thus, the RSP specifies the characteristics of the physical solutions that can meet the defined needs and includes information on market solutions to address them. Market participants can then use this information to develop the most efficient solutions, such as investments in merchant generation, demand-side projects, distributed generation, and merchant transmission. If the market responses fall short of meeting these needs, or if additional transmission infrastructure is required to facilitate the market, the RSP must also identify a regulated transmission solution.

RSPs must account for the uncertainty in assumptions about the next 10 years considering changing demand, fuel prices, technologies, market rules, environmental requirements; other relevant events; and the physical conditions under which the system might be operating. In addition, ISO-NE must also coordinate study efforts with surrounding RTOs and control area and analyze information and data presented in neighboring plans, to develop the RSP. Each report must also provide the status of proposed and ongoing transmission upgrades and justify any newly proposed transmission improvements.

RSPs must comply with NERC and NPCC criteria and standards and ISO-NE Planning and operating procedures. The RSPs must also conform to transmission owner local criteria.

Transmission system planning is now more complex than prior to electric industry restructuring as plans must consider generation market variables that include:

- Stalled merchant generator projects;
- Bankruptcies of large generating companies;
- Deactivations or retirements of aging generators;
- Potential for retirements of generators due to environmental or economic reasons; and
- Generators that, due to constraints on the transmission system, have received reliability must-run agreements from ISO-NE to help ensure continued reliable operation of the power system during peak-load periods

The transmission planning process must be dynamic and sufficiently flexible to incorporate these factors to meet increasing demands to transfer power from remote resources to load centers. In 1995, NERC described the planning process as follows:

> *Planning is the process by which changes and additions to the bulk electric system are determined. The interconnected electric systems must be able to accommodate a wide range of system conditions and contingencies - continuously varying customer demands, differing amounts and patterns of electrical generation as determined by availability and costs, and various planned and unplanned outages of the transmission facilities. This process strives to develop systems that will provide desired capability and performance in a cost-effective manner, while reliably supplying the electrical demands of customers and satisfying the business needs of electric system owners.*[1]

Maintaining the reliability of the transmission system is necessary to ensure a robust competitive marketplace for electricity, satisfy customer demands for electricity and expectations with regard to service reliability, and protect the health, welfare and safety of the public.

In the March 15, 2007 Order No. 890, "Preventing Undue Discrimination and Preference in Transmission Service," FERC has required greater transparency and openness in the transmission planning process, and has directed all transmission providers to develop a transmission planning process that satisfies nine principles, to be incorporated in a new Attachment K to their open access transmission tariffs. These principles include coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation.

As a result, ISO-NE is working with the New England transmission owners and other stakeholders to ensure that the existing, already robust transmission planning process meets these principles and addresses any areas of FERC concern. A draft Attachment K for New England regional and local planning process has been posted on the ISO-NE website and Northeast Utilities' website, and after review and input by FERC, stakeholders, and NEPOOL, will be finalized and filed with FERC by December 7, 2007.

[1] Planning Of The Bulk Electric Systems, North American Electric Reliability Council, Coordinated Planning Task Force of the Engineering Committee, May 1995

3.2 Mandatory National Reliability Standards

The New Hampshire transmission system is part of the larger New England regional grid and thus subject to the interdependencies of generation, load and transmission in neighboring electric systems. NERC recognizes that the actual planning and construction of new transmission facilities has become more complex.

In 1997, NERC stated the following that is still valid today:

> *The new competitive electricity environment is fostering an increased demand for transmission service. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and the capability of these systems to reliably support a wide variety of transfers. The future challenge will be to plan and operate transmission systems that provide the requested electric power transfers while maintaining overall system reliability. All electric utilities, transmission providers, electricity suppliers, purchasers, marketers, brokers, and society at large benefit from having reliable interconnected bulk electric systems. To ensure that these benefits continue, all industry participants must recognize the importance of planning these systems in a manner that promotes reliability.*[2]

NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure. On April 1, 2005, NERC adopted a comprehensive set of reliability standards for the bulk power system. These reliability standards incorporate the existing NERC standards and compliance requirements into an integrated and comprehensive set of measurable reliability standards. The new standards apply to all entities that play a role in maintaining the reliability of the bulk electric system in the United States.

The Energy Policy Act of 2005 required FERC to designate an entity to provide for a system of mandatory, enforceable reliability standards under FERC's oversight. This action is part of a transition from a voluntary to a mandatory system of reliability standards for the bulk-power system. In July 2006, FERC designated NERC as the nation's Electric Reliability Organization ("ERO"). The expectation of the ERO is to improve the reliability of the bulk-power system by proactively preventing situations that can lead to blackouts such as that which occurred in August 2003.

In October 2006, FERC issued a proposed rule on mandatory reliability standards as developed by NERC. FERC believes these standards, with the necessary modifications, will form the basis to develop and maintain the reliability of the North American bulk-power system. FERC approved a majority of the NERC standards and made them effective in June 2007. Other standards have since been approved or modified by FERC. These standards now have financial penalties for the users, owners or operators of the bulk-power system who fail to comply with the standards.

3.3 Technical Approval of Transmission Projects

Transmission owners coordinate with ISO-NE on the development of transmission plans. Once a transmission plan is finalized by a transmission owner, the owner must apply to ISO-NE for approval to interconnect modified or new transmission facilities under Section

[2] Planning Standards, North American Electric Reliability Council, September 1997

I.3.9 of the ISO-NE Tariff. This review and approval process was first established in the 1970s and was incorporated into the RTO structure. Section I.3.9 is an "adverse impact" test that is subject to peer review by ISO-NE and NEPOOL participants. The approval of modified or new proposed transmission plans will only be granted if the proposed transmission project does not adversely impact the bulk transmission system. If adverse results occur, mitigation measures must be included as part of the plan.

The approval process is initiated with a review of the I.3.9 studies by two NEPOOL technical task forces, the Transmission Task Force and Stability Task Force. When the task forces are satisfied that the studies demonstrate the proposed projects will have no adverse impact on the New England power system, a formal I.3.9 application is submitted to ISO-NE. ISO-NE solicits advisory input from the NEPOOL Reliability Committee. Once the I.3.9 application is recommended for approval by NEPOOL, it is then submitted to ISO-NE's Board of Directors for final approval. Following these actions, the project may proceed to construction and be placed into service.

3.4 New England Transmission Cost Allocation

The methodology for allocating transmission costs in New England has evolved through extensive stakeholder debate and consensus. In December of 2002, FERC issued an order in the New England standard market design proceeding that provided guidance for a New England transmission cost allocation methodology. After an extensive stakeholder process on July 31, 2003, NEPOOL and ISO-NE filed with FERC comprehensive Transmission Cost Allocation ("TCA") amendments to the then existing NEPOOL Open Access Transmission Service Tariff, which were subsequently accepted by FERC on December 18, 2003. Upon the operation of ISO-NE as a RTO on February 1, 2005, the TCA methodology was incorporated into the ISO-NE Tariff.

The cornerstone of the TCA methodology was the establishment of either regional cost support or participant funding for transmission projects, depending on the type of upgrade to the transmission system. The TCA methodology also changed the decision-making authority with regard to the classification of facilities and moved the determination of localized costs from NEPOOL to ISO-NE.

Regional cost support means that the costs associated with qualifying transmission facilities that provide regional benefits are rolled into the regional network service rates. These costs are then paid by all New England transmission customers under the ISO-NE Tariff.

The two types of facilities that qualify for regional cost support are Reliability Upgrades and Economic Upgrades. Together, these facilities are classified by ISO-NE as Regional Benefit Upgrades.

Treatment of Reliability Upgrades

ISO-NE identifies Reliability Upgrades through transmission system assessments conducted in accordance with the NERC, NPCC and regional planning standards. Through this assessment, ISO-NE identifies the transmission upgrades needed to ensure system stability, acceptable equipment current carrying capability under steady-state and contingency conditions, and acceptable ranges of voltage and frequency performance for New England.

Reliability Upgrade projects are added to ISO-NE's RSP after stakeholders are first given the opportunity to provide participant-funded market solutions to system reliability needs. If such solutions are not forth coming, the appropriate transmission owner is obligated to build the

Reliability Upgrade project. Reliability Upgrade projects are eligible for regional cost support if ISO-NE determines that the upgrade is needed for regional reliability. These upgrades may also produce net economic benefits for the region.

Treatment of Economic Upgrades

Economic Upgrades that are eligible for regional cost recovery are those transmission upgrades that ISO-NE determines will provide net economic benefits to the region.

Transmission Costs Not Regionalized

Transmission costs that are not included in regional network service rates for regional funding require participant funding. This distinction is intended to assure that the entities that caused the costs to be incurred, and will likely be the only entity to receive the benefits from the facility, are assigned the full costs of those facilities.

Transmission facilities in this category include the following:

- Generator Interconnection-Related Upgrades – These facilities, paid by the generator, are necessary to interconnect the generator into the New England transmission system in accordance with regional reliability standards. These facilities may include the generator's interconnection facilities, the transmission owner's interconnection facilities, and system upgrades to the regional and/or local transmission and distributions systems.
- Elective Transmission Upgrade – The cost of these facilities is allocated to those entities that have elected to construct a transmission facility for their own benefit.
- Local Benefit Upgrade – These facilities have been determined to provide no regional benefits by ISO-NE, and are thus excluded from regional rates under the ISO-NE Tariff. The cost of these facilities is paid by transmission customers under local network service tariffs.
- Merchant Transmission Facility – The costs of these facilities are paid for by the developer of the project.

Localized Costs are those costs determined by ISO-NE to be associated with Regional Benefit Upgrade projects, but are not allowed to be included in regional network rates. Localized Costs are not charged to all New England transmission customers under the ISO-NE Tariff, but instead the transmission owner needs to seek cost recovery from the appropriate transmission customers. ISO-NE's localized cost determinations are made after advisory input from the NEPOOL Reliability Committee and are conducted under Schedule 12C of the ISO-NE Tariff. ISO-NE reviews the project to ensure that it is consistent with Good Utility Practice and the current engineering design and construction practices in the area. Costs that are or would be incurred for a facility design or routing that exceed those reasonable requirements are deemed Localized Costs. In making this determination, ISO-NE considers, but is not constrained by, state and local siting decisions.

Chapter 4: TRANSMISSION SYSTEM BACKGROUND

Chapter Highlights

- PSNH's transmission facilities are an integral part of the New England transmission system.
- Transmission reinforcements have been planned and constructed to help PSNH serve increased customer demands for electricity.
- PSNH has recently completed a major transmission upgrade to its Scobie Pond Substation.

4.1 Background on PSNH's Transmission System

Transmission lines collectively form the infrastructure that is an interstate electric "highway system," moving electric energy from where it is produced to where it is used. In New England, moving electric energy is achieved primarily by the interconnected 345-kV regional bulk power system. The 345-kV transmission ties to neighboring utilities and control areas and expansion of the high voltage networks enables PSNH to meet its customers' peak demands for electricity. Operating this system at 345 kV allows for the efficient transfer of bulk power within and outside of the New Hampshire area. This integrated grid enables PSNH to efficiently transmit power throughout its franchise service territory and share in the reliability benefits of parallel transmission paths to neighboring electric systems.

The total mileage of PSNH's existing transmission circuits in New Hampshire is comprised of:

- 252 circuit-miles of 345-kV lines
- 8 circuit-miles of 230-kV lines
- 743 circuit-miles of 115-kV lines

These transmission circuits supply power to 56 substations in the PSNH service territory.

4.2 Transmission System

PSNH's transmission system is part of the interconnected New England transmission network. Transmission lines across the New England region and outside of the region are interconnected to form a transmission network, sometimes called a "grid" or "system." The transmission grid serves multiple purposes, all of which work together to enhance reliability. PSNH, ISO-NE and other electric utilities design the transmission grid to meet federal, regional and company reliability criteria. ISO-NE operates the system as one integrated network in order to provide reliable and economic delivery of energy throughout the region.

PSNH's electrical network, with its tie lines to neighboring utilities, provides a path that allows power to move freely within and over the New England transmission system. This means power can flow in any direction, depending on generation dispatch and load patterns and the configuration of the transmission system. PSNH's electrical network, in combination with tie lines to neighboring electric systems enables PSNH to rely on import capabilities. The interconnected transmission tie lines provide both PSNH and neighboring systems access to economic generation and increased reliability during emergencies.

PSNH's electrical network is composed of 345-kV and 230-kV high voltage transmission lines interconnecting with high voltage systems, principally 115 kV, to serve both a sub-area transmission function and an intra-regional function. At numerous substation locations on the network, voltage transformation is performed to enable the efficient delivery of power to area load centers. There are four major bulk power substations that tap the 345-kV and 230-kV transmission networks: the Scobie Pond and Deerfield Substations transform voltage from 345 kV to 115 kV, and the Littleton and Merrimack Substations transform voltage from 230 kV to 115 kV. Tapped at numerous locations are step-down substations for local distribution that transform voltages from either 345 kV or 115 kV to 34.5 kV and below[3].

Generating stations are interconnected at various voltages. Large central generating stations, such as PSNH Newington, ConEd Newington and Seabrook, are connected to the 345-kV transmission system. Other generating stations, like Merrimack, Schiller and Granite Ridge (only the steam generator), connect to the 115-kV system. Smaller PSNH generators and non-utility owned generating units are distributed throughout the state on the electrical network. These units typically connect to the 34.5-kV distribution system.

4.2.1 345-kV and 230-kV Systems

The PSNH 345-kV and 230-kV systems connect New Hampshire to Maine, Vermont and Massachusetts. These facilities are part of the New England bulk power transmission system. These systems, generally located across the southern part of New Hampshire, transmit power from large central generating stations like PSNH Newington, ConEd Newington and Seabrook to eight extra high voltage ties with neighboring utilities and seven step-down substations feeding the loads of PSNH and Unitil Corporation. Typically, a single 345-kV transmission line can carry over 1,000 MW of electric power.

The Deerfield and Scobie Pond 345-kV substations contain circuit breakers that interconnect several 345-kV transmission lines. The electrical configuration of these substations allow for certain elements to be out of service while maintaining the integrated nature of the substation design. Currently the Deerfield Substation contains one 450 MVA autotransformer and the Scobie Pond Substation contains two 450 MVA autotransformers that transforms voltage from 345 kV to 115 kV.

The two 230-kV lines owned by National Grid, running approximately the entire length of New Hampshire, were primarily built to bring hydro generation from the north to Massachusetts. The Merrimack and Littleton 230-kV substations tap these transmission lines. The Merrimack Substation contains a single 400 MVA autotransformer and the Littleton Substation contains a single 200 MVA autotransformer that each transforms voltage from 230 kV to 115 kV.

Operating these systems at 345 kV and 230 kV allows for the efficient transfer of bulk power within and outside of the New England area. This enables PSNH to attain maximum practicable economy in bulk power supply and share in the reliability benefits of parallel transmission paths.

4.2.2 115-kV System

[3] In 2004, FERC accepted the new line of demarcation between transmission and distribution facilities for all of the NU Operating Companies.

The 115-kV transmission system is the "backbone" of PSNH's local electric network serving distribution substations. This system loops around high load density areas in southeastern New Hampshire with ties into the western and central part of the state. The major north-south 115-kV line through New Hampshire ties the 230-kV tap in Littleton to the 115-kV loop in the south. Along this transmission corridor are east-west 115-kV taps to serve load centers throughout central New Hampshire. A 115-kV transmission line, depending on conductor size, can carry between 100 MW and 300 MW of electric power.

The 115-kV system transmits power from central generating stations like Merrimack, Schiller and Granite Ridge, 115-kV tie lines to neighboring utilities and 115-kV taps to distribution step-down substations for local area supply.

4.2.3 Electrical Tie Lines

PSNH's transmission system contains nineteen tie points to neighboring electric utilities external to New Hampshire. There are five transmission lines that interconnect with the Central Maine Power Company ("CMP"), six with the Vermont Electric Power Company ("VELCO"), seven with the National Grid and one with PSNH's affiliate, Western Massachusetts Electric Company ("WMECO").

Tie lines are a result of the coordinated planning that PSNH performed with its neighboring utilities over the past several decades. The creation of cross border tie lines is the culmination of planning techniques that has led to an overall transmission system that can more reliably and efficiently serve the customer demands for electricity.

4.2.4 Electrical Interfaces

System operators monitor the unrestricted transfer of power through the free-flowing electric system with the use of interfaces. To help system operators ensure reliability, electric these interfaces are used to assess power flows across the transmission network so performance measures are maintained within requirements. Redistribution of power flows can result when generators or transmission lines are intentionally or unintentionally removed from service. Because power flow instantaneously seeks alternate paths under these contingency conditions, the results can cause adverse impacts on local or remote systems. One method for system operators to evaluate transmission system performance and to protect it from wide area interruption is to define electrical interfaces for monitoring purposes. These are defined as sets of transmission facilities that can be used to reliably transfer power, within defined interface limits, from one area to another. The transfer limit on an electrical interface cannot be determined solely by the summation of the defined set of transmission line capabilities. The transfer limit is estimated by computer simulations that find the maximum allowable power transfer which, for pre-defined contingencies, does not violate prescribed limits of machine stability, equipment current carrying capabilities and permissible ranges of voltage and frequency.

There are four major New England transmission interfaces that include PSNH facilities that define the power transfer capability across the region.

"Maine – New Hampshire" interface: is defined by the two 345-kV transmission lines that enter New Hampshire from Maine and the two underlying 115-kV transmission lines connecting to the PSNH 115-kV Bolt Hill – Three Rivers N133 line in southern Maine.

"Northern New England Scobie + 394" interface: is defined by the 345-kV lines that enter the Scobie Substation from the Buxton Substation in Maine, Deerfield and Seabrook Substations in New Hampshire, plus the 345-kV Seabrook – Tewksbury 394 line.

"North – South" interface: is defined by the 345-kV, 230-kV and 115-kV transmission lines that enter Massachusetts from both New Hampshire and Vermont.

"East – West" interface: is defined by the 345-kV, 230kV and 115-kV transmission lines that cross the middle of New England from east to west between Long Island Sound and the Canadian border.

A further description of the New England interfaces with transfer limits can be found in the ISO-NE April 1, 2007 FERC Form No. 715 filing. The FERC Form No. 715 reporting requirement is an annual Transmission Planning and Evaluation Report, to inform potential transmission customers, State regulatory authorities, and the public of potential available transmission capacity and known constraints. Since April 1994, FERC has required each transmitting utility that operates integrated transmission system facilities rated at or above 100 kilovolts to submit annually a new Form No. 715.

Chapter 5: TRANSMISSION SYSTEM NEEDS

Chapter Highlights

- PSNH's transmission facilities are an integral part of the transmission system it shares with the rest of New England.
- PSNH is currently engaged in planning and constructing many projects that will reinforce New Hampshire's transmission system.
- To reliably and economically serve its growing electric load, PSNH needs to strengthen and upgrade its transmission system and build new facilities to resolve power transfer requirements.

PSNH's 2007 transmission plan includes the monitoring of demands for electricity and system conditions, planning for system needs and reliability and constructing upgraded or new facilities as required. This three part plan is as follows:

1. Monitor load growth projections for New Hampshire, which include PSNH, the New Hampshire Electric Cooperative, New Hampton, Ashland, Wolfeboro and Unitil Corporation. Load growth is a primary driver for the need to install new transmission facilities. Regional power transfers based on generation dispatch assumptions will also play a key role in determining the need to build new facilities. The accurate modeling and forecasting techniques support the timing of transmission expansion and ensure full utilization of existing facilities.

2. Plan transmission line and substation facility upgrades and new facilities to meet forecasted needs.

3. Construct transmission facilities that are required to meet reliability needs, reduce congestion on the grid and connect new generation to PSNH's transmission system.

The three functions above are the core of PSNH's transmission plan. The plan includes a process to monitor and change transmission plans as customer needs vary. The plan is dynamic and recognizes the ever-changing customer demands for electricity and the market for new sources of reliable and economic generation. This plan in part identifies new transmission facilities that must be installed for PSNH to reliably serve increasing customer demands for electricity.

5.1 Seacoast Area

The Seacoast Area stretches from Rochester, Dover, Portsmouth, to Hampton and Exeter. This area contains approximately 25% of the electric demand in New Hampshire. The Seacoast Area contains 345-kV and 115-kV transmission facilities. However, this area does not have a direct connection between the 345-kV and 115-kV voltage levels. The metropolitan areas of Dover, Portsmouth and Rochester are primarily served by the 115-kV transmission system. The 115-kV system integrates Schiller Station, tie lines from Maine and transmission lines from the Scobie and Deerfield substations to serve the electrical demands of this area. This area is supported by ties to the 345-kV bulk power system through 345/34.5-kV distribution step-down transformers.

Heavy power flows on the transmission line corridor between the Scobie and Schiller Substations is a result of significant load growth in the Seacoast area and along the Rt. 101

corridor. This area is served from the Scobie Substation by relatively lower-capacity transmission lines (R193, B172, H141, S153, E194, U181). Several 115/34.5-kV existing and recently constructed distribution substations are connected to these lines. In addition, during peak demand periods, power transfers from Maine with Schiller generation off-line can cause power flow to exceed equipment ratings along this path.

PSNH is investigating the feasibility and system benefits of installing 345/115-kV autotransformers in the vicinity of the Newington Substation. An autotransformer interconnection in the Seacoast area would tap generation resources on the 345-kV system at Newington and Seabrook, provide increased voltage regulation, and eliminate thermal overloads by reducing power transfers on the 115-kV transmission lines from Scobie and Deerfield. As part of this evaluation and alternative analysis PSNH is considering the benefits of rebuilding these 115-kV transmission lines in part or whole to support power flows and voltage profiles in the Seacoast area.

Transmission lines and substation facilities are also required to connect new distribution step-down transformers to the transmission system in the Seacoast area. PSNH is currently planning new transformer additions in the Rochester and Kingston areas. Depending on the location of new 115/34.5-kV substations, reconfiguration of the existing transmission system or construction of new 115-kV transmission lines may be required.

This area currently has eight projects that are active, under consideration or in the planning stages. See Tables II-1, II-2 and II-3.

5.2 Southern Area

The Southern Area stretches from Concord, Manchester, and Derry to Nashua. This area contains approximately 50% of the electric demand in New Hampshire. The Southern Area is the largest in New Hampshire. The area is dependent on internal generation and 345-kV transformation capabilities coupled with 115-kV tie line support from neighboring utilities. The interconnection of large generating plants and transmission play a vital role in serving the metropolitan areas of Concord, Manchester and Nashua. The 115-kV transmission lines in this area integrate the generation at Merrimack and Londonderry with local load centers. The area is supported by ties to the 345-kV bulk power system through 345/115-kV autotransformers or 345/34.5-kV distribution step-down transformers.

Thermal loading on transmission facilities in this area is the most pressing reliability concern during high load periods. Contingency thermal loading on transmission facilities are above emergency ratings or system voltages may fall below acceptable limits following the loss of the Scobie Pond or Deerfield 345/115-kV autotransformer. This also stresses import capabilities from neighboring electric systems. Currently, PSNH is planning the addition of a 3rd 345/115-kV autotransformer at the Scobie Substation to be installed in 2008. In addition, PSNH is investigating the need for a second 345/115-kV autotransformer at the Deerfield Substation. This plan may also include an upgrade to the 115-kV Deerfield – Madbury L175 line.

The Nashua area is served by two 115-kV transmission lines from the north originating at PSNH's Greggs and Scobie Substations. A single 115-kV line connects the Nashua area with the National Grid system in Pelham. In addition, two distribution substations tied to the 345-kV network at Amherst and Lawrence Road also serve the area's load. PSNH maintains a balance between power transfers on the 115-kV system and load serving capabilities of the 34.5-kV system at the Amherst and Lawrence Road Substations. Load growth in this area coupled with higher power transfers into Massachusetts stresses the two northern 115-kV lines into the Nashua area. In particular, the 115-kV Scobie – Hudson

X116 line exceeds its normal and emergency ratings under certain operating conditions. In 2007, PSNH completed an upgrade to the 115-kV Scobie – Hudson X116 line. In 2008, PSNH is expecting to complete the construction of a new and second 115-kV transmission line (Z119 line) between the Scobie and Hudson Substations. In addition, the Hudson Substation is being upgraded to a "breaker-and-one-half" configuration to reliably connect the new 115-kV transmission line and comply with NPCC criteria.

System impact studies have been ongoing to determine to what extent the PSNH system must comply with NPCC protection criteria to ensure reliability of the bulk power system. As a result of the preliminary analyses indicate that it may be necessary to upgrade system protection equipment at the Greggs, Garvins and Merrimack Substations to comply with the NPCC criteria for bulk power system design.

The forecasted demand for electricity in the Nashua area stresses the existing system's capabilities. PSNH is evaluating the need for additional 345/115-kV transformation in the Nashua/Milford area or at the Scobie Substation to support increased transmission power flow requirements. The interconnection of an autotransformer into the transmission system in this area may require additional 115-kV transmission facilities to be constructed.

Transmission lines and substation facilities are also required to connect new distribution step-down transformers to the transmission system in the Southern area. PSNH is currently planning new transformer additions in the Manchester, Merrimack, Londonderry, Nashua, Chester and Weare areas. Depending on the location of new 115/34.5-kV substations, reconfiguration of the existing transmission system or construction of new 115-kV transmission lines may be required.

This area currently has twenty-two projects that are active, under consideration or in the planning stages. See Tables II-1, II-2 and II-3.

5.3 Western Area

The Western Area stretches from Hillsborough to Keene to the Vermont border. This area contains approximately 10% of the electric demand in New Hampshire. The Western area has lower-capacity 115-kV tie-lines and is very dependent on the 345/115-kV Vermont Yankee Substation.

PSNH participated in an ISO-NE sponsored regional working group to address power flow conditions in western New Hampshire, Vermont and central Massachusetts. The planning studies indicated that the loss of the Vermont Yankee 345/115-kV autotransformer or the 115-kV K186 line crossing the Connecticut River causes low voltages in the area of Chestnut Hill and Brattleboro, Vermont. This contingency and others can cause local area substations to be fed from remote substations. To address these reliability impacts PSNH is constructing a new 345/115-kV transmission substation in Fitzwilliam. This new substation will tie PSNH's 345-kV 379 line to the National Grid 115-kV Bellows Falls – Pratts transmission line and to the PSNH Monadnock Substation. The substation will strengthen the 115-kV transmission system in eastern Vermont that also serves PSNH load in the Claremont area. In addition, under this plan PSNH is rebuilding the existing 115-kV Keene – Swanzey A152 line, 115-kV Greggs – Jackman F162 line and the 115-kV Garvins – Webster V182 line. PSNH is currently rebuilding the F162 line and the project is expected to be completed by December 2007.

Increased power transfers in this area will continue to strain other PSNH transmission lines. PSNH is evaluating the need to upgrade the 115-kV Keene – Monadnock T198 and Jackman - Keene L163 transmission lines.

On January 1, 2004, PSNH purchased the New Hampshire service territory of the Connecticut Valley Electric Company ("CVEC"). This new PSNH retail load is primarily located in the Claremont area. Historically this load was connected into the regional transmission system through facilities owned by the Central Vermont Public Service Company ("CVPS") and VELCO. PSNH's existing transmission facilities do not directly connect to this load. Therefore PSNH must purchase transmission wheeling services across CVPS and VELCO. PSNH will continue to monitor the reliability of service and efficiencies associated with the Vermont wheeling services. If PSNH determines that the interconnection of the Claremont load into the Vermont system does not result in acceptable service standards, then new solutions including possible connections to PSNH's system will have to be investigated and evaluated.

Transmission lines and substation facilities are also required to connect new distribution step-down transformers to the transmission system in the Western area. PSNH is currently planning new transformer additions in the Keene, Hinsdale, Westport, Hillsboro and Swanzey areas. Depending on the location of new 115/34.5-kV substations, reconfiguration of the existing transmission system or construction of new 115-kV transmission lines may be required.

If in the future load demands exceed distribution system capabilities along the southern border of New Hampshire, a new 115-kV line could be required between the Jackman and Fitzwilliam/Monadnock Substations to connect a new 115/34.5-kV substation to the transmission system in the Peterborough area.

This area currently has eleven projects that are active, under consideration or in the planning stages. See Tables II-1, II-2 and II-3.

5.4 Central Area

The Central Area or Lakes Region stretches from Sunapee and Laconia to the Mount Washington area. This area contains approximately 10% of the electric demand in New Hampshire. This area relies almost entirely upon power transfers from resources outside the area.

The Mount Washington area in particular is mountainous and difficult to serve. Presently, two radial 115-kV transmission lines share load responsibility in the Tamworth and Conway areas. The 115-kV Beebe – White Lake B112 line feeds loads in the Tamworth area. The 115-kV Maine tie line to Saco Valley feeds loads in the North Conway area. The 115-kV White Lake – Saco Valley Y138 line is operated normally open between the White Lake and Saco Valley Substations. In the event of a transmission line outage from Maine or the Beebe Substation, the Y138 line can be closed to help support demands for electricity. PSNH also relies in part on local generation from the White Lake jet to support reliable electric service in he event of contingencies.

PSNH is evaluating the reliability of the 115-kV transmission system that feeds into the northwest part of the Lakes Region. Depending on load and system conditions, the outage of transmission facilities in the northern area at the Littleton Substation (Littleton 230/115-kV autotransformer and the 115-kV Littleton - Whitefield - Beebe X178 line) may cause interruptions to PSNH loads. Of particular concern is the long-term outage of the Littleton 230/115-kV autotransformer. Loss of the Littleton autotransformer disconnects the central area from its strongest tie to the Comerford Substation. Under this condition the entire central area is served by three weak ties: 1) Moore 230/13.8-kV transformer; 2) Webster north: and the 3) 115-kV Littleton - St Johnsbury 60 line in Vermont. System voltages under contingency conditions can fall below acceptable limits and could result in voltage collapse. In addition to low voltage conditions, this contingency may cause high power flow through the Moore 230/13.8-kV transformer that could exceed its emergency ratings.

The 115-kV Littleton - Whitefield - Beebe X178/U199 line is approximately 60 miles long through the mountainous areas of northern New Hampshire. The 115-kV line connects the Littleton Substation to the central area loads through the Beebe Substation. An outage of the X178 line disconnects the entire central area from the Littleton Substation. This contingency can result in voltage collapse in the Central area. PSNH is evaluating the need to construct a second 115-kV line in parallel to X178 or bring new 345-kV facilities into this area from southern New Hampshire.

To address these reliability concerns, PSNH has long recognized the benefits of closing the 115-kV White Lake – Saco Valley Y138 line to support reliable electric service to the White Lake and Saco Valley substations and to the entire Central and Northern areas of the PSNH transmission system. Closing the Y138 line requires the addition of several facilities, including 115-kV capacitor banks at the Beebe and White Lake Substations, 115-kV circuit breaker additions at Saco Valley and White Lake, and the installation of a 115-kV phase shifting transformer at the Saco Valley Substation. This project is under construction and is expected to be in service in 2008.

Transmission lines and substation facilities are also required to connect new distribution step-down transformers to the transmission system in the Central area. PSNH is currently planning new transformer additions in the Laconia and New Hampton areas. Depending on the location of new 115/34.5-kV substations, reconfiguration of the existing transmission system or construction of new 115-kV transmission lines may be required.

In addition, PSNH recognizes the future need to reinforce the central New Hampshire region by considering the construction of 345-kV facilities emanating from the Deerfield Substation into this area and potentially beyond the area to northern New Hampshire and/or into Vermont.

This area currently has ten projects that are active, under consideration or in the planning stages. See Tables II-1, II-2 and II-3.

5.5 Northern Area

Northern New Hampshire includes the areas of Berlin, Groveton, Lincoln and Whitefield. This area contains approximately 5% of the customer demand in New Hampshire. This area is fed from the 115-kV tie lines to the National Grid system and a 115 kV intra-company line from the central region. Local generation can also support load area load demands.

Significant amount of new energy resources, including many renewable energy resources, have filed applications with ISO-NE for interconnection to the PSNH electric system in this area. PSNH is working with the New Hampshire Public Utilities Commission in developing a report to the New Hampshire Legislature on the assessment of PSNH's transmission capability and expansion issues to primarily interconnect renewable resources in the North Country in accordance with Senate Bill 140. At this time, no firm transmission upgrades have been finalized.

This area currently has no projects that are active, under consideration or in the planning stages. See Tables II-1, II-2 and II-3.

5.6 Regional Power Transfers

There are several key electrical interfaces in New Hampshire. Power imports from Maine and internal New Hampshire generation dispatches can cause restrictions on electrical interfaces due to the limited capability of PSNH's and neighboring electric systems. Transmission line structural and design limitations restrict the movement of electric energy over these transmission corridors. The following sections detail each of the major transmission interfaces in New Hampshire plus transfers into Vermont. PSNH will continue to monitor regional power transfer requirements and investigate the reliability benefits of reinforcement plans to these interfaces.

Maine – New Hampshire Interface

The Maine – New Hampshire interface is defined as the two 345-kV lines that enter New Hampshire and the two integrated underlying 115-kV lines connecting to the PSNH 115-kV Bolt Hill – Three Rivers N133 line.

Power imports on the 345-kV system can serve New Hampshire needs via the 345/115-kV autotransformers and the 345/34.5-kV step-down distribution substations. Power imports on the 115-kV system serve the electricity needs of PSNH customers in southeastern New Hampshire. New Hampshire contingencies can severely limit PSNH's ability to import power from Maine. The Deerfield autotransformer contingency removes a strong connection between the 345-kV and 115-kV systems. Following this autotransformer outage, electric power transfers increase automatically on all external tie lines and other 115-kV interconnections to the 345-kV and 230-kV systems in order to maintain electric service to New Hampshire's loads. These specific contingencies cause increased power flow on the 115-kV system in southeastern Maine as well as across the 115-kV system in the Seacoast Area. PSNH studies continue to indicate voltage and thermal restrictions to move power across the Maine – New Hampshire interface.

Studies suggest that additional dynamic voltage regulation may be necessary to control voltages to acceptable levels. There are several potential upgrades that could increase power transfers across this interface and increase voltage support in the Seacoast Area. They include the installation of dynamic voltage control equipment at the Deerfield 345-kV bus, and the re-termination of the 345-kV Buxton to Scobie 391 line into the Deerfield Substation.

The Y138 line project increases reliability in the Central Area and also has a beneficial impact on the Maine – New Hampshire interface. The normally closed line provides a new free-flowing tie-line across the interface. The tie-line brings additional power transfers into central New Hampshire. In addition, the project increases power transfer capability in New Hampshire to help support power flows into the Vermont system via PSNH tie-lines. The Y138 line project provides substantial benefits to the region and PSNH.

Currently, the Maine electric utilities are performing a comprehensive assessment of their transmission system. Preliminary results indicate the potential for transmission plans in western Maine that could affect electric service to the North Conway, New Hampshire area. These plans could also provide opportunities for PSNH to strengthen its electric system in the future with new transmission facilities tied to the Maine upgrades following their completion. Other potential Maine upgrades could include the construction of a new 345-

kV tie line between Portland and Portsmouth. This potential upgrade could connect to the 345-kV system in the vicinity of the Newington Substation. The addition of a 3rd Maine - New Hampshire 345-kV tie line could increase energy resource delivers from Maine and New Brunswick into New Hampshire.

Northern New England Scobie + 394 Interface

The Northern New England Scobie + 394 (NNE+394) interface is defined as the 345-kV lines that enter the Scobie Substation from Buxton, Deerfield and Seabrook plus the 345-kV Seabrook – Tewksbury 394 line. The most limiting contingencies in this transmission corridor involve the malfunction of a 345-kV circuit breaker at the Seabrook Substation. This single event restricts power transfers across the 345-kV system in New Hampshire. In addition, the associated reduction of reactive output from the Seabrook generator, as the result of its recent thermal MW up-rate, aggravates voltage control along the 345-kV transmission corridor. PSNH is evaluating the transmission upgrades necessary to enhance power transfers across the PSNH system.

North – South Interface

The North – South interface is defined as the 345-kV, 230-kV and 115-kV transmission lines that cross from Vermont and New Hampshire into Massachusetts. Generation imports from Maine and New Hampshire generation increase the stress on the North – South interface. ISO-NE studies indicate that the loss of the 345-kV Seabrook – Tewksbury 394 line causes the 345-kV Scobie – Sandy Pond 326 line to overload. This contingency has the greatest impact on the North – South interface. ISO-NE, PSNH and National Grid are investigating the potential to increase the transfer capability. A new 345-kV transmission line between the Scobie Substation and the Tewksbury Substation in Massachusetts will enhance regional power transfers across the 345-kV bulk power transmission network.

East – West Interface

The "East – West" interface is defined as the 345-kV, 230-kV and 115-kV transmission lines that cross the middle of New England from east to west between Long Island Sound and the Canadian border. The PSNH transmission lines that are part of this interface include the 345-kV Scobie – Amherst 379 line, 115-kV North Road – Ascutney K174 line, and the 115-kV Jackman – Keene L163 line. This interface monitors the power flows from the high concentration of generation in eastern New England to load pockets in western New England. The impact on power transfers between New York and New England also affects this interface. The need to deliver additional power across the PSNH 115-kV system to serve increased demands in Vermont contributed to the need to upgrade the F162 line. This transfer condition is also contributing to the heavy power flow on the L163 line.

6.0 THE NEW HAMPSHIRE TRANSMISSION PLAN

This section contains a summary of transmission modifications or additions to the New Hampshire electric system. Certain distribution substations are identified in the tables that require transmission facilities to connect the substation to the transmission network.

Attachment II contains three tables of transmission projects. Tables II-1 through II-3 are summarized below. During the forecast period, additional transmission projects beyond those listed may be justifiable to enhance reliability or provide efficient means to transmit electric energy. The estimated in-service dates for new facilities listed below may vary through time as the dynamics of the system change.

Attachment II Tables

Table II-1, Transmission Lines Under Construction.

Table II-2, Transmission Lines Under Planning Consideration.

Table II-3, Substation Projects – Rated 115-kV and Above.

Attachment I

Planning Process

PSNH continuously performs a transmission planning function to ensure a reliable and dependable transmission system is maintained. PSNH updates its transmission assumptions continuously so that studies done during the year reflect the best available data. The following is a summary of the transmission planning process as shown in Diagram I-1.

The transmission planning process involves numerous elements ranging from: 1) compiling generation, transmission and load system data; 2) developing aggregate electrical system models and configurations; 3) testing system models with computer simulations against pre-defined acceptance criteria; and 4) comparing alternatives that ultimately will lead to a preferred project. These elements, when combined, form a process by which the identification of modified or new transmission facilities is achieved.

Compiling of system data involves the development of models for existing transmission facilities, customer loads, and generation resources. It also includes futuristic models.

Once models are developed, they are added to a computer program that is used as an analytical tool that mimics transmission system operations. This enables testing of the models against pre-defined acceptance criteria to measure the adequacy and security of the electrical network. The core process of transmission planning is the determination of alternative expansion or reconfiguration plans that fulfill the need to provide service. Solving the service needs of customers can entail the identification of multiple solution sets.

Short- and long-term models of PSNH's electrical network are updated to incorporate changes in actual load profiles, forecast of peak demands and construction of facilities that impact delivery of electric power to area load centers. With these models, PSNH continuously performs power flow analyses and stability studies to determine system response and to develop methods to improve system operating efficiencies. The deterministic testing approach with multiple transmission contingencies, several dispatch scenarios and differing load levels is an effective means of identifying system weaknesses.

The development of alternatives includes analyses of the feasibility to modify or expand a substation or transmission rights-of-way. The comparison of all alternative solutions includes the cost-effectiveness, environmental impacts, system efficiencies and service requirements of the alternative that balances short- and long-term needs. Finally, a preferred project is chosen that PSNH believes is economic, enhances reliability, is environmentally prudent, fulfills the need to provide service, and is supportable before regulatory agencies in New Hampshire. Following this process, PSNH brings these projects to NEPOOL and ISO-NE for review and approval. Diagram I-2 is a flow chart that describes this process.

In essence, transmission planning attempts to predict the future so that its customers will have a reliable transmission system to depend on. Load serving responsibilities, reporting and predicting future system needs which include the impacts of new or retired generation is more complex under this open access environment.

Diagram I-1
Transmission Planning Process Flowchart

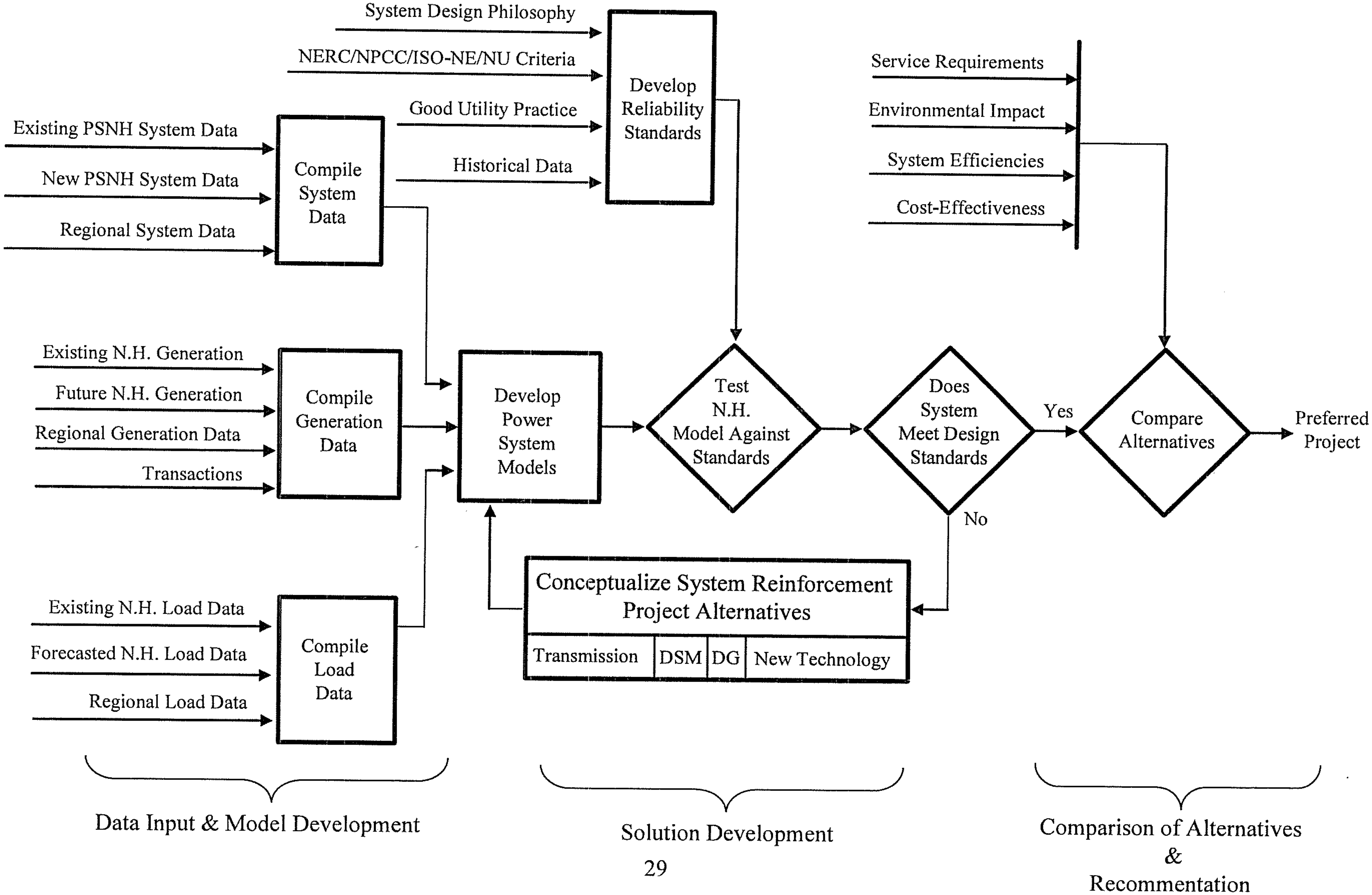
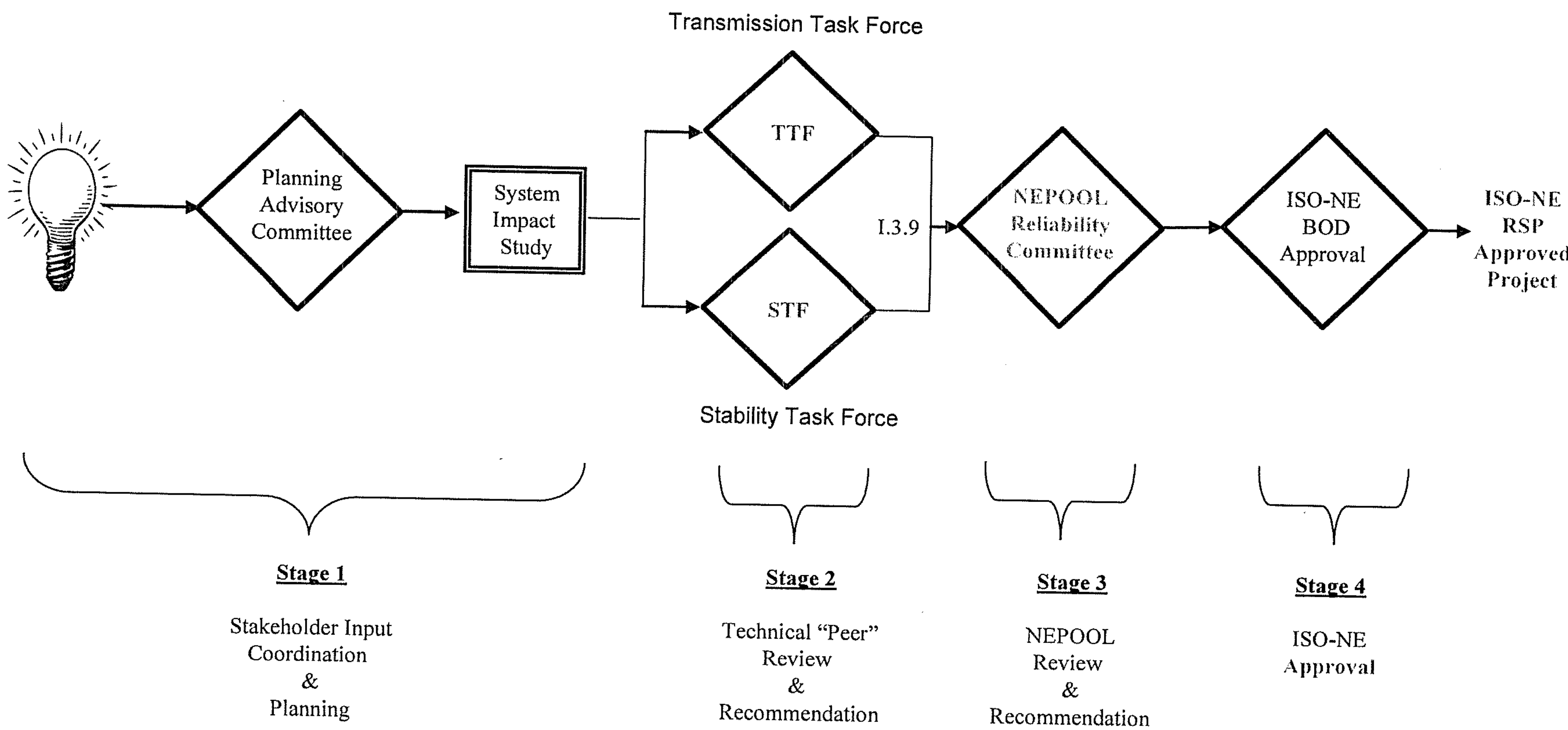


Diagram I-2
ISO-NE
Transmission Planning Process Flowchart



Attachment II
Table II-1
Transmission Lines Under Construction

From		To		Line Number	Area	Voltage kV	Length of Circuit (miles)	Project Type	Proposed ISD
Substation	City or Town	Substation	City or Town						
Scobie	Londonderry	Hudson	Hudson	Z119	Southern	115	11.2	Rebuild	2008
Jackman	Hillsboro	Greggs	Goffstown	F162	Western	115	20.4	Rebuild	2008

Attachment II
Table II-2
Transmission Lines Under Planning Consideration

From		To		Area	Voltage kV	Length of Circuit (miles)	Project Type	Proposed ISD
Substation	City or Town	Substation	City or Town					
Deerfield	Deerfield	Laconia	Laconia	Southern	115	36.4	Planned - New Line	TBD
Garvins	Bow	Webster	Franklin	Southern	115	23.8	Planned - Rebuild	2008
Keene	Keene	Chestnut Hill	Hinsdale	Western	115	5.0	Planned - Rebuild	2009
Scobie	Londonderry	Chester	Chester	Southern	115	6.0	Proposed - Rebuild	TBD
Greggs	Goffstown	Reeds Ferry	Merrimack	Southern	115	11.1	Proposed - Rebuild	TBD
Long Hill	Nashua	South Milford	Milford	Southern	115	TBD	Concept - New Line	TBD
Deerfield	Deerfield	Madbury	Madbury	Seacoast	115	12.9	Proposed - Rebuild	TBD
Dover	Dover	Rochester	Rochester	Seacoast	115	TBD	Propsed - New Line	TBD
Schiller	Portsmouth	Ocean Road	Greenland	Seacoast	115	5.4	Proposed - Rebuild	TBD
Schiller	Portsmouth	Ocean Road	Greenland	Seacoast	115	5.5	Proposed - Rebuild	TBD
Peterborough	Peterborough	Fitzwilliam	Fitzwilliam	Western	115	TBD	Concept - New Line	TBD
Jackman	Hillsboro	Peterborough	Peterborough	Western	115	TBD	Concept - New Line	TBD
White Lake	Tamworth	Ashland	Ashland	Lakes Region	115	TBD	Concept - New Line	TBD
Beebe	Campton	Pemigewasset	New Hampton	Lakes Region	115	TBD	Concept - Rebuild	TBD
Pemigewasset	New Hampton	Webster	Franklin	Lakes Region	115	TBD	Concept - Rebuild	TBD
Scobie	Londonderry	Massachsetts Border	Pelham	Southern	345	TBD	Concept - New Line	TBD
Deerfield	Deerfield	Webster	Franklin	Southern	345	TBD	Concept - New Line	TBD
Webster	Franklin	Vermont Border	Claremont	Lakes Region	345	TBD	Concept - New Line	TBD

Attachment II
Table II-3
Substation Projects - Rated 115 kV and Above

Substation	City or Town	Area	Voltage (kV)	Project Type	Proposed ISD
Beebe	Campton	Lakes Region	115	Add Capacitor Bank	2007
Fitzwilliam	Fitzwilliam	Western	345/115	New Substation	2008
Jackman	Hillsboro	Western	115/34.5	Transformer Interconnection	2008
Hudson	Hudson	Southern	115	Rebuild Substation	2008
Weare Street	Weare	Southern	115/34.5	New Substation	2008
Scobie	Londonderry	Southern	345/115	Add Autotransformer	2008
Mammoth Road	Londonderry	Southern	115/34.5	Transformer Interconnection	2008
Long Hill	Nashua	Southern	115/34.5	Transformer Interconnection	2008
Pemigewasset	New Hampton	Lakes Region	115/34.5	Transformer Interconnection	2008
White Lake	Tamworth	Lakes Region	115	Add Capacitor Bank	2008
Saco Valley	Conway	Lakes Region	115	Add Phase Shifter	2008
Thorton	Merrimack	Southern	115/34.5	New Substation	2009
Swanzey	Swanzey	Western	115/12.5	Transformer Interconnection	2009
Keene	Keene	Western	115	Add Capacitor Bank	2010
Deerfield	Deerfield	Southern	345/115	Add Autotransformer	2011
Gosling Road	Newington	Seacoast	345/115	New Substation	2011

Attachment II
Table II-3
Substation Projects - Rated 115 kV and Above

Substation	City or Town	Area	Voltage (kV)	Project Type	Proposed ISD
Webster	Franklin	Lake Region	115	Add Capacitor Bank	TBD
Laconia	Laconia	Lakes Region	115	Transformer Interconnection	TBD
Scobie	Londonderry	Southern	115/34.5	Transformer Interconnection	TBD
Greggs	Goffstown	Southern	115	Rebuild Substation	TBD
Merrimack	Bow	Southern	115	Rebuild Substation	TBD
Broad Street	Nashua	Southern	115/34.5	New Substation	TBD
Chester	Chester	Southern	115	Line Termination	TBD
Candia Road	Manchester	Southern	115/34.5	New Substation	TBD
Garvins	Bow	Southern	115	Rebuild Substation	TBD
Rochester	Rochester	Seacoast	115/34.5	Transformer Interconnection	TBD
Kingston	Kingston	Seacoast	115	Line Termination	TBD
Portland	Rochester	Seacoast	115/34.5	New Substation	TBD
Chestnut Hill	Hindsdale	Western	115/34.5	Transformer Interconnection	TBD
Westport	Westport	Western	115	Transformer Interconnection	TBD
Court Street	Keene	Western	115	New Substation	TBD