KEYSPAN
Energy Delivery

KeySpan Energy Delivery
52 Second Avenue
Waltham, MA 02451
Tel 781 466-5136
Fax 781 290-4965
E-mail toneill@keyspanenergy.com

Thomas P. O'Neill
Senior Counsel

ORIGINAL
Case No. DG 06-105
Exhibit No. 1
Panel

Via Federal Express

August 21, 2006

Debra A. Howland, Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street
Concord, NH 03301

Re: EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England
Integrated Resource Plan
DG 06-105

Dear Ms. Howland:

In accordance with the Company's previous conversation with attorney Damon enclosed please find an original and seven copies of a revised EnergyNorth Integrated Resource Plan for the period November 1, 2006 through October 31, 2011. This filing is intended to replace the filing made by the Company on August 7, 2006. An electronic copy is also being sent.

If you should have any questions, please do not hesitate to contact me at the above number.

Very truly yours,

Thomas P. O'Neill

TPO:ca
Enclosures

Cc: Office of Consumer Advocate

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EXECUTIVE SUMMARY

This Integrated Resource Plan ("IRP" or "Plan") for the period November 1, 2006 through October 31, 2011 is filed with the New Hampshire Public Utilities Commission ("Commission") by EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England ("EnergyNorth" or the "Company") in compliance with the Commission's Order No. 24,531 dated October 21, 2005 in Docket DG 04-133/DG 04-175 approving a settlement among EnergyNorth, the Office of the Consumer Advocate and the Commission Staff.

This IRP demonstrates that the Company's planning process ensures that it maintains a reliable resource portfolio and energy supply to meet the forecasted needs of its customers at the lowest possible cost. The Plan includes: (i) a step-by-step description of the methodology the Company uses to forecast demand on its system, (ii) a detailed description of the analysis the Company employs to determine its normal and design planning standards, (iii) a detailed description of how the Company develops its resource portfolio to meet customer requirements under design conditions, (iv) a complete inventory of the expected available resources in the Company's portfolio and a demonstration of the adequacy of the portfolio to meet customer demands under a range of weather and economic conditions, and (v) a description of the Company's portfolio management activities that minimize the cost of maintaining an adequate portfolio.

The Company's planning process begins with its methodology for forecasting demand using an econometric demand model to determine annual incremental growth for the traditional residential, and commercial industrial markets, and specific market analysis for non-traditional markets, including natural gas vehicles and large scale cogeneration projects. The econometric model uses the SAS statistical software package to perform data analysis that relates sales by class to factors such as population, labor force, gross state product and economic forecasts to develop annual incremental sales projections. The Company then deducts any savings expected to be achieved through the implementation of its energy efficiency programs approved by the Commission in Order No. 24,636 dated June 8, 2006 in Docket DG 06-032. The results of the incremental demand forecasting methodology indicate that, over the five year forecast period, sales in the residential market are projected to grow by an average of 167,317 MMBtu per year and sales in the commercial/industrial market are projected to grow by an average of 264,356 MMBtu per year. The Company projects no incremental growth opportunities in non-traditional markets over the forecast period. The savings resulting from the energy efficiency program are projected to reduce growth by 77,573 MMBtu per year over the forecast period for a total net sales gain of 354,100 MMBtu per year. These incremental growth projections are added to the base line, or "springboard," normalized sendout figures from the May 2005 to April 2006 split year to generate the forecasted total demand requirements. The normalized sendout springboard figures are the result of a detailed regression analysis of daily sendout versus daily effective degree days ("EDD") that establishes a strong statistical relationship between weather and load on the Company's system. The end result of the demand forecasting process projects sendout growth over the forecast period to average 361,200 MMBtu, or 2.6 %, per year under normal weather conditions.

To ensure that the Company maintains adequate supplies in its portfolio to meet customer demand, the planning process continues with a detailed cost-benefit analysis that defines the design year and design day planning standards. This cost-benefit analysis weighs the cost of not having sufficient resources against the cost of maintaining a level of reliability. The cost of not having sufficient resources is measured as the cost of customer outages including re-light costs, damage repair and lost economic output. The cost of maintaining reliability is measured as the cost of procuring an increment of supply to prevent the outage. The results of the analysis help the Company define a design year at 7,680 EDD with a probability of occurrence of 1 in 47.32 years and a design day at 80 EDD with a probability of occurrence of 1 in 42.49 years. Combining the results of the design planning standards definition and the load forecasting process, the Company is projecting design year sendout to increase over the forecast period by an average of 382,100 MMBtu, or 2.5%, per year, and design day sendout to increase by an average of 3,100 MMBtu, or 2.2%, per year. After the forecast of customer requirements are determined, the Company's planning process continues with the design of a resource portfolio to meet those requirements in the most reliable and least cost manner possible. To do this the Company uses the SENDOUT® Model (a proprietary linear programming model developed by New Energy Associates) to determine the adequacy of the existing portfolio in meeting the forecasted requirements and to identify any shortfalls during the forecast period. SENDOUT® allows the Company to determine the least-cost, economic dispatch of its existing resources subject to contractual and operating constraints, and identifies the need for, and type of additional resources during the forecast period, if any. The resources available to the Company include domestic long-haul and short-haul transportation contracts, underground storage contracts, Canadian and domestic gas supply contracts, and supplemental resources. The results of this step of the process show that the existing resource portfolio is adequate to meet base case customer requirements on a design day through the 2008/09 heating season, after which it identifies the need for an additional 5,310 MMBtu per day increasing to 19,660 MMBtu per day by the 2010/11 heating season

The next step in the planning process is to test the adequacy of the portfolio design by evaluating how it would perform under high and low alternative demand scenarios, and a cold snap weather scenario. Under the high demand scenario, the Company assumes that the annual sendout requirements under design conditions increase by 532,225 MMBtu per year on average. The Company's resource plan shows that the portfolio can meet this increased demand under design conditions with 730 MMBtus per day in 2007/08 and, 40,000 MMBtus per day in 2009/10 of incremental capacity or citygate delivered supply. In the low demand case, the Company assumes that annual sendout requirements under design conditions increase by 237,825 MMBtu per year on average. The resource plan shows that the portfolio can meet this demand with no additional incremental capacity or citygate delivered supply through the forecast period. For the cold snap weather scenario, the Company assumes that the coldest seven-day period experienced in the last twenty-three years will occur in January during an otherwise normal winter. The Company's resource plan shows that it has adequate resources available to meet cold snap sendout requirements.

Given that the Company's resource planning process results in a resource portfolio that is adequate to meet the projected requirements of its customers, the final step in the process involves the Company's portfolio management activities that minimize the cost of maintaining an adequate portfolio. These activities are described in detail in Appendix B which is the Company's Portfolio Management Plan that was filed with the Commission on December 8, 2005 in accordance with the Settlement.

In conclusion, EnergyNorth's Integrated Resource Plan demonstrates that the Company's planning process ensures that it maintains a reliable resource portfolio and energy supply to meet the forecasted needs of its customers at the lowest possible cost.

I. INTRODUCTION

This is the Integrated Resource Plan (the "IRP" or "Plan") for EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England ("EnergyNorth" or the "Company")[1] for the five-year forecasting period 2006/07 through 2010/11[2]. This filing is made in accordance with the requirement of New Hampshire Public Utilities Commission (the "Commission") Order No. 24,531, dated October 21, 2005 in Docket DG 04-133/DG 04-175, approving a settlement agreement (the "Settlement") among EnergyNorth, the Office of the Consumer Advocate, and the Commission Staff ("Staff") dated August 17, 2005. The persons to whom communications should be addressed concerning this IRP are:

Thomas P. O'Neill
Senior Counsel
KeySpan Energy Delivery New England
52 Second Avenue
Waltham, Massachusetts 02451

and

Steven V. Camerino, Esq.
McLane, Graf, Raulerson & Middleton
15 North Main Street
Concord, New Hampshire 03301

1The Local Distribution Companies ("LDCs") that operate under the name KeySpan Energy Delivery New England are: Boston Gas Company, Colonial Gas Company, Essex Gas Company and EnergyNorth Natural Gas, Inc. Unless otherwise specifically noted, the term "KeySpan" refers to all four of the New England LDCs.

2 The forecasting period is based on split years from November 1 through October 31.

A. Company Background

EnergyNorth is a local distribution company that provides natural gas sales and transportation service to nearly 84,000 residential and commercial customers in thirty cities and towns in the state of New Hampshire. Since 2000, EnergyNorth is a wholly owned subsidiary of KeySpan New England, LLC which is itself a subsidiary of KeySpan Corporation. The Company's core obligation is to provide safe, reliable and least-cost gas service to its customers.

B. Summary of the IRP Process

The purpose of this IRP is to document the process undertaken by the Company to forecast customer sendout requirements and manage its gas resource portfolio to meet that obligation.

The IRP process begins with the development of a long-range forecast of customer demand. Next, the Company matches its available resources against expected demand to determine if incremental resources are required over the forecast period. If so required, the Company would identify the resources available to meet the incremental demand requirements and procure a least-cost asset or mix of assets available. In determining the least cost available assets, the Company analyzes both price and non-price factors. Examples of non-price factors include diversity of supply source, flexibility and reliability. Next, the Company looks at its currently available assets and determines if there are any "decision points" with respect to any of its contracts such as expiration dates or options to increase or decrease volumes. If so, the Company determines whether to renew those supplies or replace them with an available alternative. Finally, the Company analyzes its portfolio of expected resources against a range of weather scenarios to determine if those resources are sufficient to reliably meet sendout requirements.

C. Organization of the Filing

This document is organized into the following principal sections:

- Section II provides an overview of the KeySpan process for identifying and meeting customer requirements;
- Section III reviews the Company's demand forecasting methodology and discusses the development of the forecast of customer sendout requirements;
- Section IV discusses the design of the resource portfolio, the expected available resources, and the adequacy of the portfolio in terms of meeting forecasted requirements; and,
- Section V discusses the Company's management of its resource portfolio.
- Section VI summarizes the Company's compliance with the terms of the Settlement.

II. OVERVIEW OF THE KEYSPAN PROCESS FOR IDENTIFYING AND MEETING CUSTOMER REQUIREMENTS

The principal objective of KeySpan's gas management process is the creation and utilization of a portfolio of gas supply, interstate pipeline transportation, underground storage and supplemental resources to meet daily and seasonal firm demand requirements in the most cost-effective manner while maintaining reliability. KeySpan's process of planning for and meeting customer load requirements on a daily basis involves the coordination of a number of activities including demand forecasting, long-term resource planning, gas supply management and gas distribution. The majority of these activities are centralized within the Regulatory Strategy and Relations Department, which includes the Company's Forecasting and Gas Supply Planning and Customer Choice groups. Regulatory Strategy and Relations coordinates closely with the Gas Control Department, which is responsible for gas deliveries across the KeySpan distribution system in New England. Both of these departments operate from the Company's Waltham, Massachusetts facility.

Among the responsibilities of Regulatory Strategy and Relations are to project the resource requirements of the KeySpan system and to assemble a least-cost portfolio of reliable resources to meet those requirements. The projection of resource requirements requires two steps: (1) the preparation of forecasts of long-term trends in customer requirements under normal weather conditions; and, (2) the preparation of forecasts of customer requirements under defined (design day and design year) weather conditions. Assembling the least-cost portfolio is also a two-step process involving: (1) the procurement of a sufficient and appropriate portfolio of resources to meet the design sendout requirements resulting from the demand forecasting process; and, (2) the economic dispatch of those volumes given available resources. The Company's resource portfolio provides a range of flexibility in making these determinations in the course of the day-to-day management of the portfolio.

KeySpan's forecasting and gas supply planning activities are complemented by a centralized dispatch and control center. The daily process of obtaining sufficient resources to meet predicted customer needs requires a high level of coordination between Regulatory Strategy and Relations and Gas Control. Each day, Gas Control provides Energy Supply with projected sendout requirements that are developed based on the results of the demand forecasting process. Regulatory Strategy and Relations determines the availability, reliability and pricing information necessary to satisfy the predicted customer loads taking into account both currently available projections of weather and prices as well as the possibility of design-forward conditions for the remainder of the heating season (design-forward planning). Regulatory strategy and Relations and Gas Control then establish a daily "Game Plan" that matches available resources with sendout requirements for the KeySpan system. The Game Plan is designed to balance the demand requirements of the system for the current gas day with scheduled supply volumes and also projects a three-day supply/demand balance.

EnergyNorth customers receive significant benefits as a result of the coordinated and centralized gas management process because resource planning and purchasing decisions are made from an overall system perspective to meet customer requirements. Given the diversity and flexibility of the resource portfolio, this decision-making framework allows EnergyNorth's resources to be utilized on the basis of efficiency rather than mere availability.

III. FORECAST METHODOLOGY

A. Introduction

EnergyNorth developed its five-year forecast of customer requirements under design weather planning conditions using the following process:

1. Forecast Incremental Sendout

   Incremental sendout is the additional sendout that EnergyNorth forecasts to occur over the five-year forecast period above the level established for an identified actual reference year, which was 2005/06 for purposes of this plan.[1] The Company used econometric models to develop a forecast of incremental sendout for traditional markets (i.e., residential, and commercial and industrial customers). Incremental sendout forecasts of non-traditional markets, such as natural-gas vehicles ("NGVs") and large-scale power generation, and demand-side management savings ("DSM") were developed outside of the econometric models because the sendout associated with these markets is not included in the historical data used to develop the econometric equations. Forecasts of incremental sendout for traditional and non-traditional markets were summed and reductions from DSM were subtracted to determine the total incremental sendout over the forecast period.

2. Develop Reference Year Sendout Using Regression Equations

   The Company then developed the reference year sendout using regression equations. The level of EnergyNorth's sendout in the 2005/06 reference year served as the "springboard" to which incremental sendout was added. The actual sendout data used for the springboard are a function of the weather conditions experienced in the reference year. Therefore, the Company uses regression equations to normalize the sendout in the reference year based on normalized weather data.

3. Normalize Forecast of Customer Requirements

   The Company summed the incremental sendout requirements with the weather-normalized springboard sendout requirements to determine EnergyNorth's total normalized forecast of customer requirements over the five-year forecast period.

[1] The reference year is the split year May 1, 2005 through April 30, 2006.

4. Determine Design Weather Planning Standards

EnergyNorth performed a cost-benefit analysis to determine the appropriate design day and design year planning standards for the development of a least-cost reliable supply portfolio over the forecast period. In accordance with the Settlement Agreement in DG 04-133/DG 04-175, the probability distribution of the effective degree days used in this analysis was determined using Monte Carlo techniques.

5. Determine Customer Requirements Under Design Weather Conditions

Using the applicable design day and design year weather planning standards, EnergyNorth determined the design year sendout requirements and the design day (peak day) sendout requirements. These design sendout requirements established the Company's resource requirements over the forecast period.

Based on the foregoing process, EnergyNorth projects incremental throughput of 1,444,800 MMBtu over the forecast period assuming normal weather (see Chart III-A-1). Overall, this growth in firm sales represents a 10.5 percent total increase in sendout requirements over the forecast period, or 2.6 percent per year on average. The development of EnergyNorth's five-year forecast of customer sendout requirements, based on the steps set forth above is described in the following sections

B. Forecast of Incremental Sendout

1. Introduction

The first step in EnergyNorth's forecast process is to prepare a five-year forecast of annual incremental sendout. Annual incremental sendout is the net increase in load that the Company expects to experience over the forecast period. This annual projection of incremental sendout is then added to the reference or "springboard" year sendout, which is derived from EnergyNorth's regression analysis of the latest split-year daily sendout and weather data, as described in Section III.C., to determine total firm sendout requirements.

The process used to forecast incremental sendout over the forecast period consists of five components. First, EnergyNorth develops a demand forecast of loads associated with traditional residential and commercial/industrial markets. To accomplish this, EnergyNorth developed econometric models, which are discussed in Section III.B.2(a). Throughput in the residential sector is discussed in Sections III.B.2 (b)(i-iii), below, and the commercial/industrial sector is discussed in Sections III.B.2. (b)(iv-vi), below.

Second, EnergyNorth develops a forecast for non-traditional markets that includes NGVs and large-scale power generation. While non-traditional markets are part of EnergyNorth's forecasting process, the Company is forecasting no demand in the NGV and large-scale cogeneration markets (Sections III.B.3.(a) and III.B.3.(b), respectively) based on the current and anticipated lack of activity in those markets. EnergyNorth's natural gas demand forecast for traditional customers, together with its forecasts of non-traditional market demands, results in a total forecast of incremental customer demand over the 2006/07 through 2010/11 forecast period.

Third, EnergyNorth accounts for the load reductions forecasted to result from the implementation of DSM, also known as gas energy efficiency programs, because these reductions are exogenous to the demand forecast generated by the econometric model. These load reductions are based on the estimated reductions prepared in conjunction with EnergyNorth's approved market transformation program (discussed in Section III.B.4, below).

Fourth, EnergyNorth monitors migration of sales customers to transportation service to determine if adjustments to its forecast are warranted (discussed in Section III.B.5, below).

Finally, EnergyNorth develops two alternatives to the base case demand forecast, that represent high and low sendout cases (discussed in Section III.B.6, below). The development of these alternative forecasts enables the Company to evaluate its ability to meet customer requirements with portfolio resources under a range of weather and economic conditions.

2. <u>Demand Forecast for Traditional Markets</u>

As mentioned above, the first step of the forecasting process is to prepare a five-year forecast of annual incremental sendout. To prepare this forecast, the Company first develops a demand forecast of loads associated with traditional residential and commercial/industrial markets using econometric models.[2] The Company began by reviewing the models specified in its 1998 Integrated Resource Plan filed with the Commission on November 30, 1998 in DR-98-134, and then updated those models by re-estimating the parameters of the models using updated historical data.

(a) The Econometric Models

The statistical models used by the Company relate sales by class to factors such as population, labor force, gas price and gross state product. Annual sales data were expanded to cover the twenty-two year period of January 1984 through December

[2] The Company agreed as part of the Settlement to develop econometric models for this forecast to replace the end-use model used in its most recent IRP.

2005. This information was used in conjunction with forecasts of economic factors provided by Global Insight, Inc. to develop the sales forecast.

The Company used the SAS statistical software package to perform the statistical data analysis that determined the relationships between the dependent variables and the explanatory variables in each of the equations used in the econometric models.

(b) The Forecast

The Company segmented its sales forecast by sector producing one forecast for residential sales and another for commercial and industrial sales.

For the residential sector, the Company tested two modeling structures. The first structure begins with forecasts of both number of residential customers and the use per residential customer. The number of customers is based on growth rates of generally available variables such as population, employment, while use per customer captures price effects, appliance saturation, and efficiency improvements. Multiplying the results of these two forecasts creates the forecast of residential sales. This structure assumes that it is easier to forecast each component separately. The second structure produces a forecast of residential sales directly, by relating total residential sales to independent variable such as gross state product and gas price. However, if one forecasts sales directly, it is possible that the effects of variables such as degree days, population and employment will overwhelm the effect of variables such as price. Because it is not clear which structure will produce the best forecast, the Company combined the results of the two models to minimize the errors that might be inherent in either one of them

For the residential sector, the Company developed a broad range of explanatory variables from sources such as the US Bureau of the Census, the US Bureau of Labor Statistics, the US Bureau of Economic Analysis, the Energy Information Administration of the US Department of Energy and the Company's own database. In nearly all cases, the Company collected statewide New Hampshire data because data specific to EnergyNorth's service territory were limited or non-existent. These variables were:

- State population
- State personal income
- State per capita income
- State wage and salary disbursement
- Statewide employment
- Statewide housing units and statewide households
- Statewide residential fuel oil sales and unit cost
- Statewide residential natural gas sales and unit cost
- Manchester, NH normal and actual degree days
- EnergyNorth therm sales and average rates to residential customers
- New Hampshire City Gate gas price

Table III-I gives additional details on these variables. Similar variables were identified for the commercial and industrial (C&I) sector:

- All of the above variables except those relating specifically to the residential sector
- EnergyNorth average rates for commercial and industrial customers
- EnergyNorth therm sales and customer totals for commercial and industrial customers
- Other EIA energy consumption and unit cost data for commercial and industrial sector

Table III-1

Variables Analyzed in Forecasting Practices

Index	Variable Name	Unit	Description	Source	Period Covered
1	CUSN	Customers	ENGI Number of Non-Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
2	CUSH	Customers	ENGI Number of Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
3	CUSR	Customers	ENGI Number of Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
4	CUSI	Customers	ENGI Number of Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
5	CUSC	Customers	ENGI Number of Commercial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
6	CUSCI	Customers	ENGI Number of Commercial and Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
7	USEN	DTH/Customer	ENGI Gas Consumption per Non-Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
8	USEH	DTH/Customer	ENGI Gas Consumption per Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
9	USER	DTH/Customer	ENGI Gas Consumption per Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
10	USEC	DTH/Customer	ENGI Gas Consumption per Commercial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
11	USEI	DTH/Customer	ENGI Gas Consumption per Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
12	USECI	DTH/Customer	ENGI Gas Consumption per C&I Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
13	USNN	DTH/Customer	ENGI Gas Consumption per Non-Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
14	USNH	DTH/Customer	ENGI Gas Consumption per Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
15	USNR	DTH/Customer	ENGI Gas Consumption per Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
16	USNC	DTH/Customer	ENGI Gas Consumption per Commercial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
17	USNI	DTH/Customer	ENGI Gas Consumption per Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
18	USNCI	DTH/Customer	ENGI Gas Consumption per C&I Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
19	GASN	DTH	ENGI Gas Consumption of Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
20	GASH	DTH	ENGI Gas Consumption of Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4

21	GASR	DTH	ENGI Gas Consumption of Non-Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
22	GASC	DTH	ENGI Gas Consumption of C&I Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
23	GASI	DTH	ENGI Gas Consumption of Commercial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
24	GASCI	DTH	ENGI Gas Consumption of Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
25	GSNN	DTH	ENGI Normal Gas Consumption of Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
26	GSNH	DTH	ENGI Normal Gas Consumption of Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
27	GSNR	DTH	ENGI Normal Gas Cons. of Non-Heating Residential Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
28	GSNC	DTH	ENGI Normal Gas Consumption of C&I Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
29	GSNI	DTH	ENGI Normal Gas Consumption of Commercial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
30	GSNCI	DTH	ENGI Normal Gas Consumption of Industrial Customers	EnergyNorth Internal Historical Records	1984Q1-2005Q4
31	CPI	1982-84 = 100	Consumer Price Index	Global Insight	1984Q1-2020Q4
32	GSP	Millions of $	NH Gross State Product—Aggregate	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
33	RGSP	Millions of 2000 $	NH Real Gross State Product—Aggregate	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
34	POP	Thousands	NH Total Population	Bureau of Census, Current Population Reports	1984Q1-2020Q4
35	NMIG	Thousands	NH Net Migration	Bureau of Census, Current Population Reports	1984Q1-2020Q4
36	EMP	Thousands	NH Employment, Total Non-Agriculture	Bureau of Labor Statistics	1984Q1-2020Q4
37	RUEM	Percent	NH Unemployment Rate	Bureau of Labor Statistics	1984Q1-2020Q4
38	UEMP	Thousands	NH Number Unemployed	Bureau of Labor Statistics	1984Q1-2020Q4
39	REMP	Thousands	NH Resident Employment	Bureau of Labor Statistics	1984Q1-2020Q4
40	LBFC	Thousands	NH Total Labor Force	Bureau of Labor Statistics	1984Q1-2020Q4
41	HH	Thousands	NH Households, Family and Non-Family	Global Insight	1984Q1-2020Q4
42	HSTM	Thousands	NH Housing Starts, Private Multi-Family	Global Insight	1984Q1-2020Q4
43	HSTS	Thousands	NH Housing Starts, Private	Global Insight	1984Q1-

			Single Family		2020Q4
44	HSTT	Thousands	NH Housing Starts, Total Private	Global Insight	1984Q1-2020Q4
45	HSOLD	Thousands	NH Home Sales, Existing Single-family units	Global Insight	1984Q1-2020Q4
46	HINC	Thousands of $	NH Average Household Income	Global Insight	1984Q1-2020Q4
47	PCI	Thousands of $	NH Per Capita Personal Income	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
48	RPCI	Thousands 2000 $	NH Real Per Capita Personal Income	Bureau of Economic Analysis	1984Q1-2020Q4
49	PINC	Millions of $	NH Personal Income, Total, By Place of Residence	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
50	RPINC	Millions of 2000 $	NH Real Personal Income, Total	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
51	RPIR	Millions of 2000 $	NH Real Income, Residence Adjustment	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
52	RPTR	Millions of 2000 $	NH Real Nonfarm Proprietors Income	Bureau of Economic Analysis	1984Q1-2020Q4
53	PITP	Millions of $	NH Personal Income, Total Proprietors Income,	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
54	TPTR	Millions of 2000 $	NH Real Total Proprietors Income	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4
55	PINF	Millions of $	NH Personal Income, Nonfarm Proprietors Income	Bureau of Economic Analysis	1984Q1-2020Q4
56	INDX	(2002=100)	NH Industrial Production Index, Total	Global Insight	1984Q1-2020Q4
57	PRCO	($/MCF)	New Hampshire #2 Heating Oil Production Price For residential Heating	U.S. Energy Information Administration	1984Q1-2005Q4
58	PRCG	($/MCF)	New Hampshire Natural Gas City Gate Price	U.S. Energy Information Administration	1984Q1-2005Q4
59	PRCR	($/MCF)	New Hampshire Residential Natural Gas Price Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
60	PRCC	($/MCF)	New Hampshire Commercial Natural Gas Price Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
61	PRCI	($/MCF)	New Hampshire Industrial Natural Gas Price Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
62	PRCCI	($/MCF)	New Hampshire C&I Natural Gas Price Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
63	EGYO	(MMCF)	New Hampshire #2 Heating Oil consumption For residential Heating	U.S. Energy Information Administration	1984Q1-2005Q4
64	EGYG	(MMCF)	New Hampshire Natural Gas consumption by All Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
65	EGYR	(MMCF)	New Hampshire Residential Natural Gas consumption Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
66	EGYC	(MMCF)	New Hampshire Commercial	U.S. Energy	1984Q1-

			Natural Gas consumption Updated on 9/14/2005	Information Administration	2005Q4
67	EGYI	(MMCF)	New Hampshire Industrial Natural Gas consumption Updated on 9/14/2005	U.S. Energy Information Administration	1984Q1-2005Q4
68	RPRR	PRCR/PRCO	Price Ratio: Res. Natural Gas Price: #2 Oil Price	U.S. Energy Information Administration	1984Q1-2005Q4
69	RPRC	PRCC/PRCO	Price Ratio: Commercial Gas Price: #2 Oil Price	U.S. Energy Information Administration	1984Q1-2005Q4
70	RPRI	PRCI/PRCO	Price Ratio: Industrial Gas Price: #2 Oil Price	U.S. Energy Information Administration	1984Q1-2005Q4
71	REGR	EGYR/EGYO	Energy Use Ratio: Res. Natural Gas: #2 Oil	U.S. Energy Information Administration	1984Q1-2005Q4
72	REGC	EGYC/EGYO	Energy Use Ratio: Commercial Gas: #2 Oil	U.S. Energy Information Administration	1984Q1-2005Q4
73	REGI	EGYI/EGYO	Energy Use Ratio: Industrial Gas: #2 Oil	U.S. Energy Information Administration	1984Q1-2005Q4
74	REVN	($)	ENGI Revenue to Residential Non-Heating Customers ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
75	REVH	($)	ENGI Revenue to Residential Heating Customers ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
76	REVR	($)	ENGI Revenue to Residential Customers ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
77	REVC	($)	ENGI Revenue to Commercial Customers ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
78	REVI	($)	ENGI Revenue to Industrial Customers ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
79	REVCI	($)	ENGI Revenue to Commercial and Industrial Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
80	RVNN	($)	ENGI Revenue (Normal) to Residential Non-Heating Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
81	RVNH	($)	ENGI Revenue (Normal) to Residential Heating Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
82	RVNR	($)	ENGI Revenue (Normal) to Residential Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
83	RVNC	($)	ENGI Revenue (Normal) to Commercial Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
84	RVNI	($)	ENGI Revenue (Normal) to	EnergyNorth Billing	1984Q1-

			Industrial Customer ($)	Frequency Record	2005Q4
85	RVNCI	($)	ENGI Revenue (Normal) to C&I Customer ($)	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
86	CHGN	($/MMBTU)	ENGI Company Charge to Residential Non-Heating Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
87	CHGH	($/MMBTU)	ENGI Company Charge to Residential Heating Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
88	CHGR	($/MMBTU)	ENGI Company Charge to Residential Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
89	CHGC	($/MMBTU)	ENGI Company Charge to Commercial Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
90	CHGI	($/MMBTU)	ENGI Company Charge to Industrial Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
91	CHGCI	($/MMBTU)	ENGI Company Charge to C&I Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
92	CHNN	($/MMBTU)	ENGI Company charge (Normal) to Res. Non-Heating Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
93	CHNH	($/MMBTU)	ENGI Company charge (Normal) to Res. Heating Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
94	CHNR	($/MMBTU)	ENGI Company charge (Normal) to Residential Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
95	CHNC	($/MMBTU)	ENGI Company charge (Normal) to Commercial Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
96	CHNI	($/MMBTU)	ENGI Company charge (Normal) to Industrial Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
97	CHNCI	($/MMBTU)	ENGI Company charge (Normal) to C&I Customer =$/MMBTU	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
98	CDDN		Normal Calendar Degree Days	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
99	CDDA		Actual Calendar Degree Days	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
100	BDDN		Normal Billing Degree Days	EnergyNorth Billing Frequency Record	1984Q1-2005Q4
101	BDDA		Actual Billing Degree Days	EnergyNorth Billing	1984Q1-

As was done in the 1998 forecast, the Company developed models based on quarterly data. This approach accounts for the seasonality of both customer and sales data. For some variables, such as population and employment, data were only available annually. In these instances, the Company assumed that the data were for quarter four, and interpolated for quarters one, two and three. Although, SAS offers a variety of forecasting models including dynamic regression, Box-Jenkins, exponential smoothing, and moving averages, the Company focused on dynamic regression (i.e. econometrics) because it is the most commonly used method in the utility industry and allows the user to develop relationships between independent or explanatory variables and energy sales.

In addition to the explanatory variables, SAS allows the user to incorporate both lagged variables and autocorrelation functions into the models. When developing a forecasting model, there will always be "error" when comparing the "fit" of the model to the actual data. One would expect, however, that these errors (or residuals) would be relatively small and random in nature. If the errors are not random (e.g., every fourth quarter the forecast is too high and every second quarter it is too low), then a pattern exists and the error terms are not random. In these instances better models should be designed. Both lagged variables and autocorrelation functions are intended to eliminate the non-random components of the errors.

Because SAS allows the user to develop a large number of models, it is important to develop criteria regarding what constitutes a "good" model. In general the Company applied the following criteria:

- The t-tests for all explanatory variables are significant (i.e. exceed 1.0)[3]
- The relationship between the dependent and explanatory variable is logical and of the correct sign (e.g., higher gas prices should produce lower sales)
- The resulting forecast is reasonable (e.g., a forecast that shows sales decreasing to zero by year 2010 would be eliminated regardless of the power of the other statistics).
- That significant autocorrelation between the residuals (errors) has been eliminated (i.e. Durbin-Watson statistic is insignificant)
- The addition of new variables does not improve model performance
- Reliable forecasts of the independent variables are available.

i. Residential Customer Forecast

The Company found that there is significant seasonality to the residential customer data with a higher customer base in the winter than in the summer. Therefore, each of the econometric models developed for residential customers contained a term for residential customers lagged one period and an autocorrelation function of period four. These were by far the most significant variables for all models tested.

Following these adjustments, the most significant variables in order were population (Pop), employment (EMP) and gross state product (GSP). The four models specified passed the criteria mentioned above. One contains gross state product as the primary explanatory variable, the second employment, the third population, and the fourth contains both gross state product and population. In addition, the Company chose the Box-Jenkins ARIMA method in SAS as the time-series model and estimated an equation consistent with this approach. An additional time series model, Winter's Exponential

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[3] The Company attempted to maintain t-tests at the 2.0 significance level, but in some cases found it necessary to retain some variables that tested between 1.0 and 2.0 to maintain the theoretical form of the equations.

Smoothing, was chosen as a final model for each forecast segment. The details of these models is contained in Appendix A.

After completing the estimation of the parameters for each equation in the above models, the Company then applied a forecast of the explanatory variables to the model to produce the forecast of residential customers. The forecasts of the explanatory variables were provided by Global Insight, Inc., with which the Company has a contract to provide forecasts of energy, economic, and demographic variables for its service territory.

Three sources were used for forecasted data:

- The US Bureau of Economic Analysis — this source provided forecasts for population, gross state product, employment and wages for 1998, 2000, 2005 and 2010 at the state level.
- The Energy Information Agency — this source provided NH pricing data for natural gas city gate plus average MMBtu unit pricing and consumption data by end user classification for electricity, #2 fuel oil; #6 residual oil, LPG and natural gas, forecast annually for 2006 through 2030.
- SAS was used to produce its own forecasts of independent variables where no other forecast existed.

Using the model specifications described above, six residential customer forecasts were produced:

1. Forecast A1 used a model specification containing NH gross state product (GSP), an autoregressive term of period four (AUTO(-4)), and residential customers lagged one period (CUSR-1) as the independent variables. The GSP forecast was from the US Bureau of Economic Analysis. This forecast predicts a growth rate of 3.0 percent from year 2005/06 to year 2010/2011 and a total number of residential customers in 2010/11 of 84,172.

2. Forecast A2 used a model specification containing NH employment (EMP), an autoregressive term of period four (AUTO(-4)), and residential customers lagged one period (CUSR-1) as the independent variables. The EMP forecast was from the US Bureau of Economic Analysis. This forecast predicts a growth rate of **0.8** percent with a total number of residential customers in year 2010/11 of 74,772.

3. Forecast A3 used a model specification containing population (POP), an autoregressive term of period four (AUTO(-4)), and residential customers lagged one period (CUSR-1). The population forecast was from the US Bureau of Economic Analysis, This forecast predicts a 2005/06 to 2010/11 growth rate of 0.7 percent with the total number of residential customers in 2010/11 of 74,660.

4. Forecast A4 is the same as A3 except that NH gross state product (GSP) was added. This forecast predicts a growth rate of 2.5 percent with a total number of residential customers in 2010/11 of 81,918.

5. Forecast A5 uses the SAS Box-Jenkins ARIMA model. This forecast predicts a growth rate of 2.1 percent with the expected number of residential customers in 2010/11 being 80,612.

6. Forecast A6 uses a multiplicative Winter's exponential smoothing model with linear trend and multiplicative seasonality. It forecasts a growth rate of 2.1 percent and a total of 79,981 residential customers by 2010/11.

These forecasts were then combined to produce the aggregate residential customer forecast for EnergyNorth (see Table III-2). Each econometric model specification received a weight of 0.15 and each time series model received a weight of 0.20. Forecasts AI through A4 were averaged and given a combined weighting of 0.60. The time series forecasts A5 and A6 were also averaged and received a combined weighting of 0.40.

Table III-2
EnergyNorth Forecast Results
Residential Customer Forecast

Model	A1	A2	A3	A4	ARIMA	Winter's	Weighted Residential Customers
Dependent	CUSR	CUSR	CUSR	CUSR	CUSR	CUSR	
Independent	Intercept	CUSR_1	CUSR_1	CUSR_1			
	CUSR_1	EMP	POP	GSP			
	GSP	AUTO(-4)	AUTO(-4)	POP			
	AUTO(-4)			AUTO(-4)			
Weight	15.00%	15.00%	15.00%	15.00%	20.00%	20.00%	100.00%
Residential Customer Forecast -- Percent Growth from Base Year (2005)							
2006Q4-2007Q3	2.90%	0.78%	0.83%	2.49%	2.79%	2.40%	2.09%
2007Q4-2008Q3	3.03%	0.80%	0.79%	2.52%	2.21%	2.02%	1.93%
2008Q4-2009Q3	3.15%	0.77%	0.71%	2.59%	1.56%	1.98%	1.81%
2009Q4-2010Q3	3.06%	0.74%	0.66%	2.47%	1.83%	1.94%	1.82%
2010Q4-2011Q3	2.94%	0.77%	0.68%	2.35%	1.95%	1.91%	1.81%
Average	3.02%	0.77%	0.73%	2.48%	2.07%	2.05%	1.89%
Residential Customer Forecast (Annual)							
2005Q4-2006Q3	72,552	71,950	71,981	72,470	72,768	72,263	72,349
2006Q4-2007Q3	74,659	72,510	72,575	74,273	74,799	73,995	73,861
2007Q4-2008Q3	76,917	73,089	73,150	76,145	76,449	75,492	75,283
2008Q4-2009Q3	79,342	73,653	73,672	78,114	77,644	76,988	76,644
2009Q4-2010Q3	81,772	74,197	74,155	80,039	79,067	78,485	78,035
2010Q4-2011Q3	84,172	74,772	74,660	81,918	80,612	79,981	79,447
Average	78,236	73,362	73,366	77,160	76,890	76,201	75,937

The result shown in Table III-2 is a forecasted growth rate in residential customers from 2005/06 - 2010/11 of 1.9 percent with a total of 79,447 residential customers expected in 2010/11. See the complete residential customer forecast results Appendix A.

ii. Residential Use Per Customer Forecast

For the residential use per customer forecast, there was a strong relationship between normalized use per customer and normal degree days. Therefore, each of the models developed for use per customer used normal degree days as an independent variable. The Company also applied an autocorrelation term of period four. Following these adjustments, the econometric models included variables for NH GSP and natural gas city gate price NH and then again with per capita income replacing NH GSP.

Using the model specifications described above, four residential use per customer forecasts were produced:

1. Forecast B1 used a model specification containing NH gross state product (GSP), natural gas city gate price lagged one quarter (PRCG_1), normal degree days (CDDN), and an autoregressive term of period four (AUTO(-4)). Again, the GSP forecast was from the US Bureau of Economic Analysis, natural gas city gate price was from the Energy Information Administration, and normal degree days are a thirty year average based on National Weather Service data for Manchester, NH. This forecast predicts a growth rate of 1.2 percent from year 2005/06 to year 2010/11 and a total annual residential use per customer in 2010/11 of 91 MMBtu.

2. Forecast B2 used a model specification containing NH per capita income (PCI), natural gas city gate price lagged one quarter (PRCG_1), normal degree days (CDDN), and an autoregressive term of period four (AUTO(-4)). The NH per capita income forecast was calculated using population and personal income data from the US Bureau of Economic Analysis, natural gas city gate price and normal degree day data was the same as described in description of the B1 forecast. This forecast predicts a growth rate of 0.95 percent from year 2005/06 to year 2010/11 and a total annual residential use per customer in 2010/11 of 89 MMBtu.

3. Forecast B3 uses the Box-Jenkins ARIMA model. This forecast predicts a growth rate of -0.2 percent with the total annual residential use per customer declining from 88 MMBtu per year in 2005/06 to 86 MMBtu in 2010/11.

4. Forecast B4 uses a multiplicative Winter's exponential smoothing model with linear trend and multiplicative seasonality. It also forecasts a declining growth rate of -0.1 percent and a total residential use per customer holding virtually steady at 85 MMBtu per year from 2005/06 to 2010/11.

These forecasts were then combined to produce the aggregate residential use per customer forecast for EnergyNorth (see Table III-3). Both of the econometric models received a weight of 0.20 and each time series model received a weight of 0.30. Forecasts B 1 and B2 were averaged and given a combined weighting of 0.40. The time series forecasts, B3 and B4, are also averaged and received a combined weighting of 0.60.

See the complete residential use per customer forecast results in Appendix A.

Table III-3

EnergyNorth Forecast Results

Residential Gas Use Per Customer Forecast

Model	B1	B2	ARIMA	Winter's	Weighted Residential Use Per
Dependent	USNR	USNR	USNR	USNR	
Independent	PRCG_1	PRCG_1			
	GSP	PCI			
	CDDN	CDDN			
	AUTO(-4)	AUTO(-4)			
Weight	20.00%	20.00%	30.00%	30.00%	100.00%
Residential Use Per Customer Forecast -- Percent Growth from Base Year (2005)					
2006Q4-2007Q3	1.21%	0.97%	-2.13%	2.81%	0.77%
2007Q4-2008Q3	1.24%	1.00%	3.34%	-0.84%	1.17%
2008Q4-2009Q3	1.34%	1.03%	-0.76%	-0.84%	0.39%
2009Q4-2010Q3	1.22%	0.94%	-1.09%	-0.85%	0.26%
2010Q4-2011Q3	1.14%	0.81%	-0.59%	-0.86%	0.31%
Average	1.23%	0.95%	-0.24%	-0.11%	0.58%
Residential Use Per Customer Forecast (Annual)					
2005Q4-2006Q3	85	85	88	85	86
2006Q4-2007Q3	86	86	86	88	86
2007Q4-2008Q3	87	86	89	87	87
2008Q4-2009Q3	88	87	88	86	88
2009Q4-2010Q3	90	88	87	86	88
2010Q4-2011Q3	91	89	86	85	88
Average	88	87	87	86	87

iii. Residential Sales Forecast

As mentioned previously, residential sales forecasts were developed by (1) combining the residential customer and use per customer forecasts and (2) by independently forecasting residential sales. All data on residential sales were normalized by EnergyNorth to account for deviations in weather.

Two econometric models were developed for residential sales using quarterly data. In each case an autoregressive term of period four was used. The first model also included a term for NH gross state product (GSP). This forecast, C1, produced a 2005/06-2010/11 growth rate of 2.8 percent with total residential sales of 7.38 million MMBtu in 2010/11. The second model, C2, was the similar to C1, but also included the term natural gas city gate price. The resulting forecast C2 showed a growth rate of 3.0 percent and total residential sales in 2010/11 of 7.37 million therms.

A time series forecast, C3, uses the ARIMA model. This forecast predicts a growth rate of 1.6 percent, with total annual residential sales of 6.90 million MMBtu in 2010/11 These forecasts were then combined to produce the weighted residential therm sales forecast for EnergyNorth (see Table III-4 and Figure III-1). Both of the econometric models received a weight of 0.30 resulting in forecasts C1 and C2. These were then averaged and given a combined weighting of 0.60. The time series model C3 received a weight of 0.40. The weighted residential sales forecast shows a growth rate of 2.5 percent and sales of 7.19 million MMBtu in the year 2010/11.

Next, the Company produced a forecast of residential sales using the aggregate of the residential customer models (A1 through A6) multiplied times the aggregate of the residential use per customer models (B 1 through B4). The product of these two aggregated forecasts yielded a calculated residential sales forecast reflecting an overall growth rate of 2.4 percent and MMBtu sales forecast of 6.98 million in the year 2010/11. Combining the calculated residential sales forecast with the weighted (C1 through C3) sales forecast on an equal (50%/50%) basis, produced a final residential sales forecast of 7.08 million therms in 2010/11 for an annualized growth rate of 2.5 percent from 2005/06-2010/11.

Table III-4

EnergyNorth Forecast Results

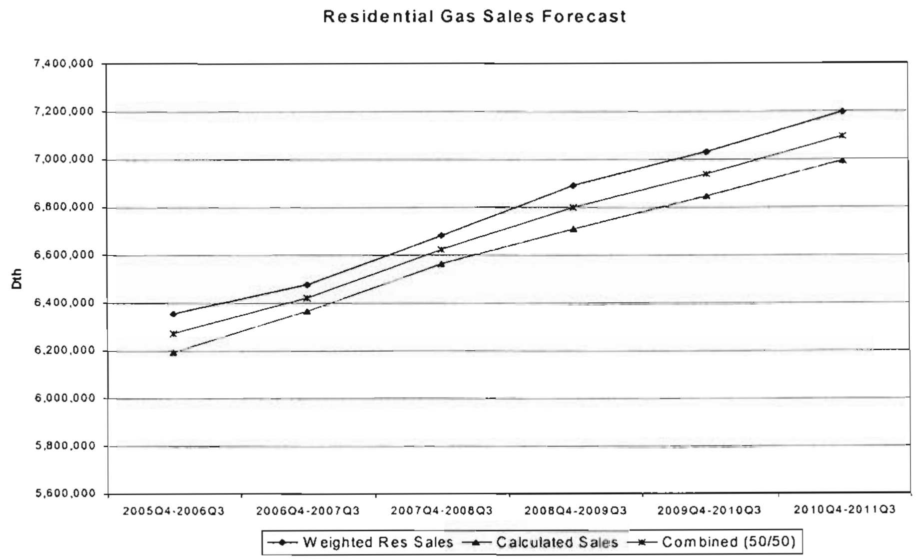
Residential Gas Sales Forecast

Model	C1	C2	ARIMA	Weighted Residential Sales	Calculated Sales	Combined (50/50)
Dependent	GSNR	GSNR	GSNR			
Independent	GSP Auto(-4)	PRCG GSP Auto(-4)				
Weight	30.00%	30.00%	40.00%	100.00%		
Residential Gas Sales Forecast -- Percent Growth from Base Year (2005)						
2006Q4-2007Q3	2.57%	2.86%	0.80%	1.96%	2.80%	2.37%
2007Q4-2008Q3	2.65%	2.91%	3.65%	3.12%	3.08%	3.10%
2008Q4-2009Q3	3.02%	3.23%	3.07%	3.10%	2.21%	2.66%
2009Q4-2010Q3	2.86%	3.00%	0.69%	2.05%	2.04%	2.05%
2010Q4-2011Q3	2.79%	2.88%	1.56%	2.34%	2.14%	2.24%
Average	2.78%	2.98%	1.95%	2.51%	2.45%	2.48%
Residential Gas Sales Forecast (Dth) (Annual)						
2005Q4-2006Q3	6,440,173	6,373,218	6,267,804	6,351,139	6,190,483	6,270,811
2006Q4-2007Q3	6,605,996	6,555,369	6,318,014	6,475,615	6,363,654	6,419,635
2007Q4-2008Q3	6,780,906	6,745,872	6,548,691	6,677,510	6,559,457	6,618,483
2008Q4-2009Q3	6,985,470	6,963,457	6,749,937	6,884,653	6,704,409	6,794,531
2009Q4-2010Q3	7,185,317	7,172,667	6,796,495	7,025,993	6,841,297	6,933,645
2010Q4-2011Q3	7,385,507	7,379,427	6,902,273	7,190,389	6,987,414	7,088,902
Average	6,897,228	6,865,002	6,597,202	6,767,550	6,607,786	6,687,668

See the complete residential load forecast results in Appendix A.

Figure III-1

Residential Natural Gas Sales Forecast



iv. C&I Customer Forecast

Similar to the residential customer models, the C&I customer models show seasonality as well as a strong relationship to population, employment and NH gross state product. Three econometric models were developed for C&I customers. All three models included autoregressive terms of period four (AUTO(-4)) and a lagged term of period one (CUSCI_1). Forecast D1, which includes the U.S. Bureau of Economic Analysis population data (POP), results in 11,448 commercial and industrial customers in 2010/11, equivalent to an annualized growth rate of 1.8 percent.

The second model substitutes labor force (LBFC) for population. This forecast, D2, predicts a growth rate of 1.7 percent per year from 2005/06-2010/11 with a total commercial and industrial customer population of 11,413 by 2010/11.

The third model substitutes NH gross state product (GSP) for employment. This forecast, D3, predicts a growth rate of 6.3 percent per year from 2005/06-2010/11 with a total commercial and industrial customer population of 14,425 by 2010/11.

The Box-Jenkins ARIMA Model is the fourth C&I customer forecast, and is designated D4. This forecast, D4, predicts a growth rate of 2.5 percent per year from 2005/06-2010/11 with a total commercial and industrial customer population of 11,942 by 2010/11.

A Winter's Exponential Smoothing Model was used as the fifth model of C&I customers. This produced a 2010/11 forecast of C&I customers of 11,843 with a growth rate of 2.6 percent through the year 2010/11.

Forecasts Dl, D2 and D3, the econometric models, are based on population, employment and state GSP projections. Forecasts D4 (Box-Jenkins) and DS (Winters Exponential Smoothing) are time series projections. All five forecasts were given weights of 20 percent each and then were averaged, with the result giving the econometric models a weight of 60 percent and the time series models a weight of 40 percent. The combination of these forecasts produces a final prediction of commercial and industrial customers for EnergyNorth for 2010/11 of 12,214 or 3.0 percent growth per year from 2005/06-2010/11.

The annual forecast results for commercial and industrial customers can be seen in Table III-5. Complete details of the C&I customer forecast results can be found in Appendix A.

Table III-5
EnergyNorth Forecast Results
Commercial and Industrial Customer Forecast

Model	D1	D2	D3	ARIMA	Winter's	Weighted C&I Customers
Dependent	CUSCI	CUSCI	CUSCI	CUSCI	CUSCI	
Independent	CUSCI_1	CUSCI_1	CUSCI_1			
	POP	LBFC	GSP			
	AUTO(-4)	AUTO(-4)	AUTO(-4)			
Weight	20.00%	20.00%	20.00%	20.00%	20.00%	100.00%
Commercial & Industrial Customer Forecast -- Percent Growth from Base Year (2005)						
2006Q4-2007Q3	2.04%	1.95%	5.87%	2.55%	2.69%	3.03%
2007Q4-2008Q3	1.77%	1.70%	6.33%	2.63%	2.61%	3.04%
2008Q4-2009Q3	1.88%	1.83%	6.54%	2.53%	2.55%	3.13%
2009Q4-2010Q3	1.69%	1.67%	6.44%	2.43%	2.48%	3.04%
2010Q4-2011Q3	1.47%	1.43%	6.19%	2.42%	2.42%	2.91%
Average	1.77%	1.72%	6.27%	2.51%	2.55%	3.03%
Commercial & Industrial Customer Forecast (Annual)						
2005Q4-2006Q3	10,486	10,482	10,643	10,549	10,442	10,520
2006Q4-2007Q3	10,700	10,687	11,267	10,818	10,723	10,839
2007Q4-2008Q3	10,890	10,869	11,980	11,102	11,003	11,169
2008Q4-2009Q3	11,094	11,068	12,764	11,382	11,283	11,518
2009Q4-2010Q3	11,281	11,253	13,585	11,659	11,563	11,868
2010Q4-2011Q3	11,448	11,413	14,425	11,942	11,843	12,214
Average	10,983	10,962	12,444	11,242	11,143	11,355

v. C&I Use Per Customer

For C&I use per customer, the Company developed three econometric models and one time series model. All three econometric models included autoregressive terms of period four, the Energy Information Agency's natural gas city gate price projections for NH and normal degree days for Manchester, NH. Forecast E1, which also includes U.S. Bureau of Economic Analysis NH GSP data, results in 805 annual commercial and industrial

MMBtu use per customer in 2010/11, equivalent to an annualized growth rate of 1.9 percent.

Forecast E2, substitutes U.S. Bureau of Economic Analysis employment data in place of NH GSP. This forecast, E2, shows a decline from 2005/06 to 2010/11 to 702 annual commercial and industrial MMBtu use per customer in 2010/11, equivalent to an average rate of -0.6 percent.

Forecast E3 substitutes per capita income data in place of employment. This forecast, E3, show an average growth rate of 1.4 percent with 779 annual commercial and industrial MMBtu use per customer in 2010/11.

The Box-Jenkins ARIMA model for the time series forecast, model, E4 produced a forecast of C&I use per customer of 747 MMBtu in 2010/11, reflecting a slight decrease in C&I use per customer growth, -0.5 percent through 2010/11.

All four forecasts were combined and averaged using a weighting of 75 percent econometric and 25 percent time series. . The results produced a forecast of 758 C&I MMBtu per customer in 2010/11 that is equivalent to a 0.6 percent annualized growth rate from 2005/06 through 2010/11.

See Table III-6 for the C&I use per customer forecast results and appendix A for complete forecast results.

Table III-6

EnergyNorth Forecast Results

Commercial and Industrial Gas Use Per Customer Forecast

Model	E1	E2	E3	ARIMA	Weighted C & I Use Per
Dependent	USNCI	USNCI	USNCI	USNCI	
Independent	PRCG	PRCG	PRCG		
	GSP	EMP	PCI		
	CDDN	CDDN	CDDN		
	AUTO(-4)	AUTO(-4)	AUTO(-4)		
Weight	25.00%	25.00%	25.00%	25.00%	100.00%
Commercial & Industrial Use Per Customer Forecast -- Percent Growth from Base Year (2005)					
2006Q4-2007Q3	1.45%	-0.86%	0.98%	0.93%	0.63%
2007Q4-2008Q3	1.77%	-0.63%	1.28%	-1.74%	0.15%
2008Q4-2009Q3	2.19%	-0.53%	1.56%	-1.71%	0.38%
2009Q4-2010Q3	2.09%	-0.50%	1.54%	-0.30%	0.74%
2010Q4-2011Q3	2.05%	-0.49%	1.37%	0.43%	0.88%
Average	1.91%	-0.60%	1.35%	-0.48%	0.56%
Commercial & Industrial Use Per Customer Forecast (Annual)					
2005Q4-2006Q3	733	724	728	765	738
2006Q4-2007Q3	743	718	735	773	742
2007Q4-2008Q3	756	713	745	759	743
2008Q4-2009Q3	773	709	756	746	746
2009Q4-2010Q3	789	706	768	744	752
2010Q4-2011Q3	805	702	779	747	758
Average	767	712	752	756	747

vi. C&I Sales Forecast

As with the residential models, the Company forecast C&I sales in MMBtu normalized for weather. Models were developed by combining the C&I customer and use per customer data, as well as directly using econometric and time series methods. Using quarterly data, the Company developed an econometric model with autoregressive terms of period four (AUTO(-4)) along with natural gas city gate price data (PRCG) collected from the EIA. In the first econometric model, F1, a lagged term of period one (GSNCI_1) was also included. This model produced a forecast of 9.52 million

MMBtu for the C&I sector in 2010/11 equivalent to a 3.8 percent growth rate for the period 2005/06 through 2010/11.

The second econometric model, F2, replaces the lagged term of period one with an autoregressive term of period eight (AUTO(-8)). This model produced a forecast of 9.47 million MMBtu for the C&I sector in 2010/11 equivalent to a 1.9 percent growth rate for the period 2005/06 through 2010/11.

The third econometric model, F3, reinserts the lagged term of period one (GSNCI_1) and continues using natural gas city gate prices (PRCG) and the autoregressive terms of periods four (AUTO(-4)) and eight (AUTO(-8)). This model produced a forecast of 9.47 million MMBtu for the C&I sector in 2010/11 equivalent to a 3.7 percent growth rate for the period 2005/06 through 2010/11.

The Box-Jenkins ARIMA model, F4, produced a forecast of 9.27 million MMBtu for the C&I sector in 2010/11 or an annualized growth rate of 2.8 percent.

The final C&I therm load weighted forecast was an average of Forecast Fl through F3 (the econometric models) at 20 percent each, with Forecast F4 (the time series forecast) weighted at 40%. Then, the weighted C&I sales forecasts and the product of the number of customers times the use per customer forecast were combined equally (50/50). The result was a forecast of 9.32 million MMBtu in 2010/11, equivalent to a 3.8 percent growth rate from 2005/06 through 2010/11.

See Figure III-2 and Table III-7 for the C&I therm load forecast summary and Appendix A for complete details of the forecast.

Table III-7

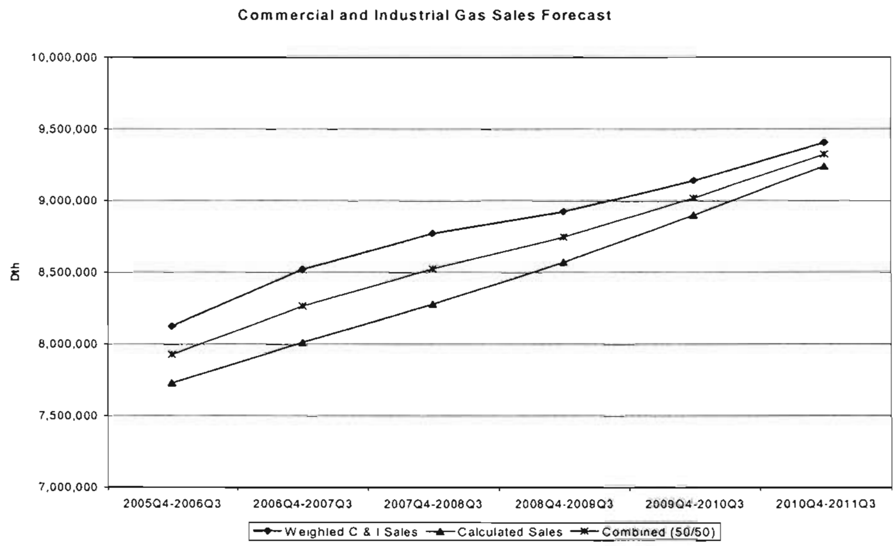
EnergyNorth Forecast Results

Commercial and Industrial Gas Sales Forecast

Model	F1	F2	F3	ARIMA	Weighted C & I Sales	Calculated Sales	Combined (50/50)
Dependent	GSNCI	GSNCI	GSNCI	USNCI			
Independent	GSNCI_1	PRCG	GSNCI_1				
	PRCG	AUTO(-4)	PRCG				
	AUTO(-4)	AUTO(-8)	AUTO(-4)				
			AUTO(-8)				
Weight	20.00%	20.00%	20.00%	40.00%	100.00%		
Commercial & Industrial Gas Sales Forecast (Percent Growth from Base Year (2005)							
2006Q4-2007Q3	5.34%	2.73%	5.55%	5.46%	4.87%	3.57%	6.85%
2007Q4-2008Q3	4.03%	1.56%	3.78%	2.75%	2.96%	3.34%	3.15%
2008Q4-2009Q3	3.53%	1.60%	3.33%	0.09%	1.72%	3.51%	2.59%
2009Q4-2010Q3	3.09%	1.71%	2.95%	2.20%	2.43%	3.85%	3.12%
2010Q4-2011Q3	2.75%	1.81%	2.64%	3.69%	2.90%	3.84%	3.36%
Average	3.75%	1.88%	3.65%	2.84%	2.98%	3.62%	3.81%
Commercial & Industrial Gas Sales Forecast (Dth) (Annual)							
2005Q4-2006Q3	7,924,343	8,628,982	7,919,898	8,067,522	8,121,654	7,734,162	7,734,162
2006Q4-2007Q3	8,347,166	8,864,129	8,359,073	8,508,086	8,517,308	8,010,453	8,263,881
2007Q4-2008Q3	8,683,945	9,002,617	8,675,271	8,742,207	8,769,249	8,278,350	8,523,800
2008Q4-2009Q3	8,990,327	9,146,297	8,964,552	8,749,767	8,920,142	8,569,259	8,744,701
2009Q4-2010Q3	9,268,498	9,302,969	9,228,745	8,942,571	9,137,071	8,898,799	9,017,935
2010Q4-2011Q3	9,523,502	9,471,707	9,472,064	9,272,510	9,402,459	9,240,153	9,321,306
Average	8,789,630	9,069,450	8,769,934	8,713,777	8,811,314	8,455,196	8,600,964

Figure III-2

Commercial & Industrial Firm Sales & Transportation Forecast



vii. Summary of Final Forecast

For the final forecast, the Company averages of forecasts developed using the several equations specified to produce a more accurate forecast than using a single equation. In this way, the forecast minimizes the forecast error associated with any single equation.

The range of forecasts produced by these models creates a distribution around the final forecast. This provides the Company with an assessment of uncertainty and allows it to plan for high growth and low growth conditions. These high growth and low growth scenarios are discussed in more detail in Section 6, Sensitivity Analysis.

Table III-8 summarizes the ENGI forecast by sector.

Table III-8

EnergyNorth Natural Gas, Inc. – Five Year Forecast

Five Year Forecast (2005 - 2010) (MMBtu)						
	Year	Residential	Commercial & Industrial	DSM	Total Demand	% Change
		(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)	
	2005Q4-2006Q3	6,270,811	7,924,379	-77573	14,117,617	
1	2006Q4-2007Q3	6,419,635	8,263,881	-77573	14,605,942	3.46%
2	2007Q4-2008Q3	6,618,483	8,523,800	-77573	15,064,710	3.14%
3	2008Q4-2009Q3	6,794,531	8,744,701	-77573	15,461,659	2.63%
4	2009Q4-2010Q3	6,933,645	9,017,935	-77573	15,874,007	2.67%
5	2010Q4-2011Q3	7,088,902	9,321,306	-77573	16,332,634	2.89%
	Average	6,771,039	8,774,324	-77573	15,467,790	2.96%

(c) <u>Forecast of Incremental Demand for Traditional Markets</u>

EnergyNorth's incremental demand forecasts (base case) for traditional markets are presented in Chart III-B-1. The incremental demand forecast is calculated as the year-to-year change in demand that results from the econometric forecast models. The Company adds the annual incremental demand determined in this way to the reference year sendout described in Section III C. As set forth in Chart III-B-1, EnergyNorth projects total net throughput additions over the forecast period (2006/07 through 2010/11) of 1,416,400 MMBtu for traditional core markets. Overall, this growth in traditional-market firm sales represents a 10.0 percent increase in sendout requirements over the forecast period, or 2.5 percent per year on average (see Chart III-A-1).

The following sections describe the specific steps involved with the development of EnergyNorth's incremental demand forecast for traditional market segments, including residential, and commercial and industrial customers.

(i) Residential Market

Chart III-B-1 presents EnergyNorth's demand forecast for residential customers. This forecast shows 573,247 MMBtu of net incremental load additions over the forecast period. Chart III-B-1 shows that EnergyNorth is projected to add an average of 143,312 MMBtu net load annually, between 2006/07 and 2010/11. As shown on Chart III-A-1, this growth in residential sales represents an overall increase in residential sendout of 2.3 percent per year on average or 9.3 percent over the forecast period.

(ii) Commercial and Industrial Market

Chart III-B-1 presents EnergyNorth's updated commercial and industrial demand forecast. This forecast shows 843,153 MMBtu of net incremental load over the forecast period. Chart III-B-1 shows that EnergyNorth is projected to add an average of 210,788 MMBtus net load annually between 2006/07 and 2010/11. As shown on Chart III-A-1, this increase in commercial/industrial sales represents an overall increase in commercial/industrial sendout of 2.6 percent per year on average, or 10.6 percent over the forecast period.

3. Demand Forecast for Non-Traditional Markets

(a) Natural Gas Vehicles

As shown on Chart III-B-1, the Company's forecast indicates no demand in the natural gas vehicle market in the EnergyNorth service territory. The Company's forecast of demand in the NGV market is driven by governmental regulations requiring or encouraging NGV use among certain commercial and governmental vehicle fleets, and the Company's marketing efforts with those vehicle fleet operators. At the time that this forecast was prepared, the Company's marketing representatives did not anticipate any significant demand in this market.

(b) Large-Scale Cogeneration Market

EnergyNorth's assessment of the large-scale cogeneration market is that the natural gas required to meet the demands of the potential customers in this market during the forecast period will not have an impact on EnergyNorth's sendout requirements or resource plan. EnergyNorth is not currently aware of any large-scale gas-fired cogeneration facilities planned for locations within the EnergyNorth service territory over the forecast period that do not yet have their natural gas requirements in place. However, consistent with EnergyNorth's recent experience, if a new gas-fired cogeneration power plant were to be located in EnergyNorth's service territory, EnergyNorth believes that the gas requirements of such facilities would likely be served by third-party gas suppliers in conjunction with Supplier Service provided by EnergyNorth from the city gate to the facility. Accordingly, EnergyNorth's forecast shows no demand for the large-scale cogeneration market and no impact on the resource plan.

4. Demand-Side Management

EnergyNorth is in the first year of a three-year extension of its energy efficiency program approved by the Commission in Order No. 24,636 dated June 8, 2006 in Docket DG 06-032. Subject to Commission review and approval, EnergyNorth expects to continue its efficiency program beyond the April 30, 2009 expiration of the current plan through to the end of the forecast period. EnergyNorth estimates volume reductions of 77,573 MMBtus per year on average from DSM measures during the forecast period (see Chart III-B-1). To develop projections of future energy-savings impacts of the DSM programs, EnergyNorth utilized a spreadsheet developed within the NSTAR Energy Efficiency Collaborative (hereinafter referred to as the "Energy Efficiency Model").[4] The Energy Efficiency Model is used to track costs and benefits relating to energy efficiency and market transformation programs. Once data is input to the Energy Efficiency Model it calculates the present value of program benefits and costs and produces a cost/benefit ratio. In addition, the output of the model also includes a projection of future energy savings for each program analyzed. In addition, EnergyNorth updated the Energy Efficiency Model in 2004 to reflect current assumptions relating to program costs and benefits, program participation, the discount rate, and avoided natural gas costs. For the analyses conducted to estimate the future savings from EnergyNorth's DSM programs, funding for all programs was assumed to continue through the forecast period ending October 2011. Savings from program measures are reflected in the model over the entire useful life of measures.

[4] The NSTAR model was initially developed to analyze electric energy-efficiency programs in Massachusetts. Northeast Efficiency Energy Partnerships ("NEEP") built the first version of the model in 1997 to analyze the costs and benefits of its regional programs. In January 1998, ComElectric retained GDS Associates, Inc. ("GDS") to perform a cost/benefit analysis of its electric energy-efficiency programs. During the first quarter of 1998, GDS enhanced the NEEP model and calculated benefit/cost ratios for ComElectric's programs. In 2000, following the BECo/Commonwealth merger, NSTAR retained Optimal Energy to enhance the model to analyze natural gas energy-efficiency programs. KeySpan used the enhanced model in December 2000 and January 2001 to analyze the costs and benefits of five regional GasNetworks energy-efficiency programs. KeySpan now uses a new GDS model to calculate the benefits and costs of its energy efficiency programs. The GDS model was initially used for projects for Fitchburg Gas and Electric. Many GDS clients now use the GDS model, including KeySpan, Efficiency Maine, the Vermont Department of Public Service, the New Hampshire Electric Cooperative, Public Service of New Mexico and other GDS clients.

5. Sensitivity Analysis

(a) Overview

EnergyNorth's resource portfolio must be designed to have adequate and reliable resources available to meet forecasted demand at the lowest possible cost. Because the future cannot be predicted with precision, the Company must evaluate whether the portfolio resources will be adequate and reliable when actual experience departs from the forecast. Specifically, EnergyNorth considered the levels of uncertainty in the demand and sendout forecasts and developed high- and low-demand scenarios relative to the base case forecast to determine the impact a range of alternatives would have on its resource portfolio. A comparison of the average annual load additions for the base case, high- and low-demand scenarios is presented in Chart III-B-2.

(b) Development of Demand Scenarios

EnergyNorth used the results of the econometric models to develop the high and low demand scenarios. Each econometric model for customers, use per customer and sales, for both the residential and commercial/industrial classes, generates a 95 percent confidence interval around the forecasted values. For the high case, the Company used the higher bounds of the interval for each model to calculate the high demand values. Similarly, for the low case, the Company used the lower bounds of the interval for each model to calculate the low demand values.

(i) High-Demand Scenario

The high-demand scenario, shown in Chart III-B-3, results in net additions of 1,975,243 MMBtu compared to 1,416,400 MMBtu in the base case (see Chart III-B-1). For the high-demand scenario, EnergyNorth incorporates the upper bound of the 95 percent confidence interval on the number of residential customer models (A1 – A4, ARIMA and Winters Smoothing) and commercial/industrial models (D1 – D3, ARIMA and Winters Smoothing) and weighted the results as it did in the base case to forecast the high case number of customers for each class respectively. It used similar upper bounds of the residential use per customer models (B1, B2, ARIMA and Winters Smoothing) and commercial/industrial models (E1 – E3 and ARIMA) and weighted the results to forecast the higher case use per customer for each class. It used the upper bound of the confidence interval on the residential sales models (C1, C2 and ARIMA) and commercial/industrial models (F1 - F3 and ARIMA) and weighted the results to forecast sales. Finally, it combined 50/50 the results of the calculated sales, based on the weighted average number of customers and use per customer, and the weighted results of the sales forecast models to determine the overall high case forecast.

(ii) Low-Demand Scenario

The low-demand scenario, shown in Chart III-B-4 , results in net additions of 877,322 MMBtu compared to 1,416,400 MMBtu in the base case (see Chart III-B-1). For the low-demand scenario, EnergyNorth incorporated the lower bound of the 95 percent confidence interval on the number of residential customer models (A1 – A4, ARIMA and Winters Smoothing) and commercial/industrial models (D1 – D3, ARIMA and Winters Smoothing) and weighted the results as it did in the base case to forecast the low case number of customers for each class respectively. It used similar lower bounds of the residential use per customer models (B1, B2, ARIMA and Winters Smoothing) and commercial/industrial models (E1 – E3 and ARIMA) and weighted the results to forecast the lower case use per customer for each class. It used the lower bound of the confidence interval on the residential sales models (C1, C2 and ARIMA) and commercial/industrial models (F1 - F3 and ARIMA) and weighted the results to forecast sales. Finally, it combined 50/50 the results of the calculated sales, based on the weighted average number of customers and use per customer, and the weighted results of the sales forecast models to determine the overall low case forecast.

6. Transportation Migration

(a) Introduction

With the introduction of the EnergyNorth's commercial/industrial (C&I) transportation program in 2001, EnergyNorth has gained a number of years of experience with unbundled transportation service in New Hampshire. See Chart III-B-5 for the Company's transportation customer activity since 2001. EnergyNorth currently has in place a comprehensive customer-choice program that provides C&I customers with an opportunity to share in the benefits provided by increased competition in the retail market for natural gas.

(b) Impact of Transportation Migration on Sendout Requirements

The Company's resource portfolio is currently structured to have a high level of flexibility to adapt to changing market conditions and regulatory obligations. This is especially true with respect to the Company's domestic gas commodity commitments.

Generally speaking, EnergyNorth enters into agreements that allow it the flexibility to eliminate up to 100 percent of its existing domestic gas commodity purchases in less than a twelve-month period. With respect to capacity resources, EnergyNorth currently has an obligation to plan for the needs of firm customers. Therefore, the Company plans for the needs of sales customers and assigns a pro-rata share of pipeline capacity, underground storage capacity and supplement resources to third-party suppliers ("Suppliers") on behalf of those sales customers who convert to Supplier Service.[5] Under the Company's Delivery Terms and Conditions, capacity is assigned to Suppliers, on behalf of migrating sales customers, in block increments based on the profile of the aggregated customer group served by the Supplier (rather than on a customer-by-customer basis). The Supplier is assigned an initial block of capacity that is subject to monthly changes consistent with increases or decreases (in increments of 200 MMBtu) in the customer load served by the Supplier. EnergyNorth retains recall rights on the capacity contracts that are released to Suppliers on behalf of their customers to ensure that the capacity remains available to serve load within the EnergyNorth service territory. In addition, the Company monitors the addition of transportation customers, who elect Supplier Service directly and are not eligible for mandatory capacity assignment. . For EnergyNorth, the customer load opting directly for Supplier Service (without first becoming a Sales Service customer) is relatively small in proportion to the Company's overall firm sendout. For the annual period May 2003 through April 2004, such load represented approximately 1.4% of the Company's total firm sendout and for

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[5] In accordance with the Company's Delivery Terms and Conditions, new customers (as defined by a meter location) who have not previously been served by the Company as a sales customer, may opt directly to Supplier Service, and therefore, are not eligible for mandatory capacity assignment.

the annual period May 2004 through April 2005 there were no new customers who opted to go directly to Supplier Service. For the period May 2005 through April 2006, one customer representing less than 0.03% of the Company's total load went directly to Supplier Service

On March 3, 2006, the Commission issued an Order of Notice in docket DG 06-33 regarding Northern Utilities' proposal regarding planning for Grandfathered Customer transportation load. KeySpan was made a mandatory party. During the course of that proceeding, the Company agreed to include in its IRP filing a discussion of the issues raised by Northern Utilities with regard to whether it is appropriate to begin planning for all or at least a portion of grandfathered customers' gas supply needs.[6] As noted above, EnergyNorth is not currently responsible for planning for the gas supply needs of Grandfathered Customers. Rather, the Company's obligation is limited to ensuring adequate on-system capacity for these customers.

The Company has considered the Northern Utilities proposal and believes that there are two key factors that must be seriously considered before a change in the Commission's policy regarding an LDC's obligation to plan for the upstream capacity resource requirements of Grandfathered customers is implemented. First: does the level of grandfathered transportation load and the historical performance of marketers supplying that load threaten the reliability of the local distribution system? And second: What is the appropriate cost recovery mechanism for the cost of planning for the upstream capacity requirements of Grandfathered Customers.

[6] Under the Northern proposal, Northern would plan for 30% of the peak day requirement of Grandfathered customers and the cost of that capacity would be borne solely by those Grandfathered customers.

At this time, based on the historical performance of Grandfathered Customers and the volumes represented by those customers, EnergyNorth does not believe that a change in the Commission's unbundling policy as it applies to EnergyNorth is warranted. First, as noted above, Grandfathered Customer load has remained constant since 2003/04. Second, the Company reviewed the daily delivery history of Suppliers doing business on the Company's system during the winter periods of November through March for the years 2003 through 2006.[7] As shown in Charts III-B-6, III-B-7 and III-B-8 there have been minimal delivery failures attributable to underdeliveries by Suppliers on behalf of transportation customers. Moreover, it is impossible to separate the underdeliveries for Grandfathered Customers deliveries from the non-Grandfathered Customer deliveries as Suppliers balance at the pool level.

If despite this data, the Commission determines that it is appropriate for the Company to plan for the upstream capacity needs of grandfathered customers, the Company suggests that it would be appropriate to plan for 100% of those needs rather than only a portion of it and to require that all customers pay for the cost of acquiring any necessary incremental resources. Regarding the level of need to plan for, assuming the Commission determines as a matter of policy that the Company should plan for the needs of Grandfathered Customer load to ensure system reliability, the Company can determine no practical or historical basis to choose a level less than 100% of that load. With regards to cost allocation, if the Company were responsible for planning for the capacity requirements of formerly Grandfathered Customers, the Company would include this load as part of its normal planning process and combine

[7] Because balancing is not done by individual customer, but rather, across the Supplier's "pool" of customers, the Company's review of deliveries made by a Supplier include deliveries made on behalf of both Grandfathered

this need with the needs of the Company's remaining customers. As the capacity and any associated supply would be contracted for as part of the Company's overall needs, and available for use by all customers, it would be impractical to allocate specific 'pieces' of capacity to certain customers. Accordingly, the Company would propose to have the incremental cost paid for by all customers, including Grandfathered Customers.

The Company will continue to monitor growth in new transportation load opting directly for Supplier Service to determine whether, in the future, the Company's growth forecasts should be adjusted. To the extent that the Company projects a need for incremental capacity on the peak day, the Company will consider the trend in these transportation loads as a factor in determining the best way to meet that need. In the interim, the Company will rely on the Commission approved penalties for underdeliveries by suppliers serving the Company's customers as an appropriate deterrent to prevent suppliers from failing to meet their supply obligation to customers.

C. Regression Analysis

In the second step of EnergyNorth's forecasting methodology set forth in Section III.A, above, the Company uses regression equations of daily sendout versus daily temperature for the most recent twelve months to calculate the reference-year "springboard." This serves as the most accurate starting point for EnergyNorth to forecast its future customer requirements. Once this step is completed, the incremental sendout requirements developed in Section III.B are added to the reference-year

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Customers and customers who were assigned capacity by the Company.

sendout requirements to determine EnergyNorth's total normalized forecast of customer requirements over the forecast period.

To establish normal-year springboard sendout requirements, the Company developed a linear-regression equation using data for the reference-year period May 1, 2005 through April 30, 2006[8]. Through the use of the linear-regression equation, the Company is able to normalize daily sendout. Specifically, the actual daily firm sendout is regressed against the daily effective degree day ("EDD") data provided by the Company's weather services provider, Meteorologix, EDD data lagged by one day, and a weekend dummy variable. These data elements were selected for the regression analysis since these elements have been, and continue to be, the major explanatory variables underlying EnergyNorth's sendout requirements.

In this filing, EnergyNorth has selected the Manchester, New Hampshire weather station as the source of the weather data that is used as the principal explanatory variable in its regression equations. The Manchester weather station is close to the center of the Company's service territory, on a load-weighted basis, and it does not have temperature biases that other weather stations (e.g. Concord) have due to topography. Specifically, the Company used the EDD value that is measured for each 24-hour period of 10 a.m. to 10 a.m., which constitutes KeySpan's Gas Day. EDD captures both the average temperature of the day as well as the effect that the wind has in increasing customer requirements.

Each year, EnergyNorth observes seasonal variations in the use-per-EDD requirements of its firm sales customers. These requirements increase going into the

[8] The Company's design year springboard incorporates observations from the 2003/04 split year, the year in which EnergyNorth experienced a design day, as more reflective of what might occur during design weather.

heating season, plateau in the December through February time period, and then decrease in the later months of the heating season. To capture this experience within the regression equation, EnergyNorth used monthly independent variables for September through June to model this seasonal change. Each monthly variable has a coefficient of zero for all days not in its respective time period and a coefficient of the actual EDD value for the days within its time period. The resulting coefficient is then the heating increment for the given time period. The positive signs on the coefficients imply that as EDD increases, the Company's sendout requirements increase as well, which corresponds with the experience of KeySpan.

EnergyNorth also observed the increase in the explanatory power of the regression equation through the inclusion of the one-day lagged EDD value. The underlying theory of this analysis is that heating requirements increase as two consecutive days of cold weather occur, which cools down structures to a greater degree than would be experienced on a single day. The variable contains the prior day's EDD value, except for the months of July and August where this value is set to zero to reflect the fact that there is no heating requirement in the summer. The positive sign of the coefficients indicates that two days of cold weather increases the heating requirement over that experienced for one cold day.

Finally, EnergyNorth observes changes in sendout requirements between weekdays and weekends, which can be attributed to differences in load requirements occurring during the workweek as compared to the weekend. To model this, the regression equation includes a weekend dummy variable that is set to 1 on Saturdays and Sundays and 0 on weekdays. A negative coefficient for the weekend variable implies a load reduction on weekend days versus weekday days, all other factors being equal. The functional form of the equation is given in Chart III-C-1. Chart III-C-2 sets forth the regression coefficients for the EnergyNorth system. The adjusted R-square is 0.982, and all of the t-statistics of the independent variables are greater than 2.0, indicating that these variables are significant to the explanatory power of the equation.

This regression equation captures the observed characteristics of the Company's sendout requirements. The observed characteristics include the following: (1) sendout requirements are directly related to EDD; (2) sendout requirements change on a seasonal basis; (3) sendout requirements are affected by EDDs that occur over a multi-day period; and (4) sendout requirements differ by day of the week. Thus, EnergyNorth has developed a set of reliable regression equations to establish the basis upon which future sendout requirements can be forecast. Using its forecast of load additions and an appropriate set of daily EDD values for a design year, the Company can successfully plan its operational requirements to provide a low-cost, adequate and reliable supply of natural gas to its customers.

D. Normalized Forecasts of Customer Requirements By Year

In the third step of the Company's forecasting methodology set forth in Section III.A, above, the Company combines the May 2005 – April 2006 reference-year sendout, which is derived from the regression analysis, with the annual incremental sendout forecast discussed in Section III.B, to yield the following forecast of customer requirements under normal weather conditions:

Base Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	2007-08	2008-09	2009-10	2010-11
Heating Season	9,441,300	9,757,800	9,904,300	10,125,700	10,377,200
Non-Heating Season	3,813,000	3,950,100	4,064,600	4,184,600	4,321,900
Total	13,254,300	13,707,900	13,968,900	14,310,300	14,699,100
Per-Annum Growth		3.4 %	1.9 %	2.4 %	2.7 %

The heating season is defined as the months of November through March; the non-heating season is defined as the months of April through October.

High Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	2007-08	2008-09	2009-10	2010-11
Heating Season	9,691,000	10,114,200	10,341,000	10,647,900	10,986,400
Non-Heating Season	3,957,600	4,155,700	4,318,400	4,488,600	4,677,000
Total	13,648,600	14,269,900	14,659,400	15,136,500	15,663,400
Per-Annum Growth		4.6 %	2.7 %	3.3 %	3.5 %

Low Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	2007-08	2008-09	2009-10	2010-11
Heating Season	9,179,000	9,394,000	9,465,300	9,606,700	9,777,500
Non-Heating Season	3,659,300	3,734,700	3,800,500	3,870,000	3,955,500
Total	12,838,300	13,128,700	13,265,800	13,476,700	13,733,000
Per-Annum Growth		2.3 %	1.0 %	1.6 %	1.9 %

E. Planning Standards

In the fourth step of the Company's forecasting methodology, the Company performs a cost-benefit analysis to determine the appropriate design-day and design-year planning standards to develop a least-cost reliable supply portfolio over the forecast period.

1. Incorporation of the Monte Carlo Methodology

a. Background

In its previous IRP filing, the Company relied on a cost/benefit analysis methodology for the purposes of establishing design planning standards. This cost/benefit methodology used, as input data, time series of actual EDD observations that begin in January 1981 to estimate frequencies of occurrence of two types of extreme weather events: a design day and a design year. These two types of standards are significant in that the design day standard determines the most cost-effective amount of transportation capacity (both interstate and supplemental) and the design year standard determines the most cost-effective amount of storage supply to maintain to ensure reliable service to the Company's customers.

The design day standard, which specifies the most cost-effective amount of transportation capacity (both interstate and supplemental), has been based on the statistical distribution of the coldest day of each calendar year. The design year standard, which specifies the most cost-effective amount of storage supply, has been based on the statistical distribution of the total EDDs in each calendar year. The mean and standard deviation of the normal distribution of each of these data sets has been used as the weighing factor in the probability-weighted 'benefit' estimate, i.e. the value of the avoidance of damages were the Company to plan for a design day/year lower than what might occur.

b. The Theory of the Company's Monte Carlo Methodology

For its 2006 IRP, KeySpan has used a Monte Carlo simulation method to generate synthetic daily EDD values for Manchester, NH for purposes of establishing design planning standards. The application of this Monte Carlo method provides the Company with a much larger time series of daily EDD values on which to base the theoretical 'benefit' values of its cost/benefit analysis.

The Monte Carlo methodology generally implies the generation of a dataset of synthetic values, larger than a given dataset of actual observations, based on the observed statistical properties of the actual dataset. The larger size of the synthetic dataset (3,000 simulated years) can assist in the determination of the likelihood of extreme weather events, such as those the Company seeks to define in its cost/benefit analysis of its design standards.

In developing a time series of daily EDD values much larger than the Company's existing actual historical observations from 1981-present, greater consideration had to be given than to generate 365 random values for each year of the synthetic dataset. First, consideration of the seasonality of EDD values had to be given. Second, consideration of the interdependence of one day's EDD value with the prior day's value had to be given, as well. To generate its set of synthetic data values, the Company chose to model its EDD data using a first-order autoregressive process (denoted AR(1)). Such a model has been commonly assumed for meteorological time series.

Letting X_t denote the EDD value on the t^{th} day, the AR(1) process requires that the conditional probability distribution of X, given the past record of observed EDD, X_{t-1},

$X_{t-2}, \ldots$, depends only on X_{t-1}, the observed EDD value for the previous day. This property can be expressed as:

$$X_t - \mu = \Phi(X_{t-1} - \mu) + \epsilon_t, \qquad (1)$$

where the daily EDD values are expressed in terms of deviations from their common mean μ, and Φ denotes the first-order autocorrelation coefficient. The error terms (ϵ_t) in equation (1) are assumed to constitute a "white-noise process"; that is, they are uncorrelated random variables with zero mean and constant variance σ_ϵ^2. It is further assumed that the ϵ_t, are normally distributed [denoted $N(0, \sigma_\epsilon^2)$].

The first-order autocorrelation coefficient Φ measures the degree of dependence between the EDD values on consecutive days, X_{t-1} and X_t. A value of $\Phi = 0$ implies that X_{t-1} and X_t are uncorrelated (i.e., X_t is completely unpredictable from the past record of daily EDD), whereas a value of $\Phi = 1$ or -1 implies that the X_t are perfectly correlated (i.e., X_t is completely predictable). For daily EDD time series, typically $0 < \Phi < l$, meaning that the X_t are positively, but not perfectly, correlated. An AR(1) process is stationary (i.e., all the joint probability distributions of the X, are time invariant) if $| \Phi | < 1$. Although daily EDD time series are clearly nonstationary because seasonal cycles are present, the stationarity assumption is a reasonable approximation when dealing with a single month. Besides this day-to-day stationarity, it is also assumed that the monthly time series are stationary from year to year; in other words, that the climate over its recent history (since 1981, say) has not changed in a statistical sense.

The requirement that the error term ϵ_t is normally distributed implies that the daily EDD X_t also is normally distributed. Letting σ^2 denote the variance of X_t, it is straightforward to show that σ^2 is related to σ_ϵ^2, the variance of an error term, by

$$\sigma_\epsilon^2 = (1 - \Phi^2)\,\sigma^2 \qquad (2)$$

We see by equation (2), that the stronger the dependence between X_{t-1} and X_t, the greater the reduction in the variance of an error term relative to the variance of daily EDD. More importantly, (2) implies that an AR(1) process can be completely characterized in terms of three parameters, μ and, say Φ and σ^2.

c. <u>The Application of the Company's Monte Carlo Methodology: Introduction</u>

To determine the three parameters, μ, Φ and σ^2 required for the AR(1) process, while considering the seasonality of EDD values, the Company began by determining the mean observed EDD value for each calendar day within its existing dataset (Figure 1).

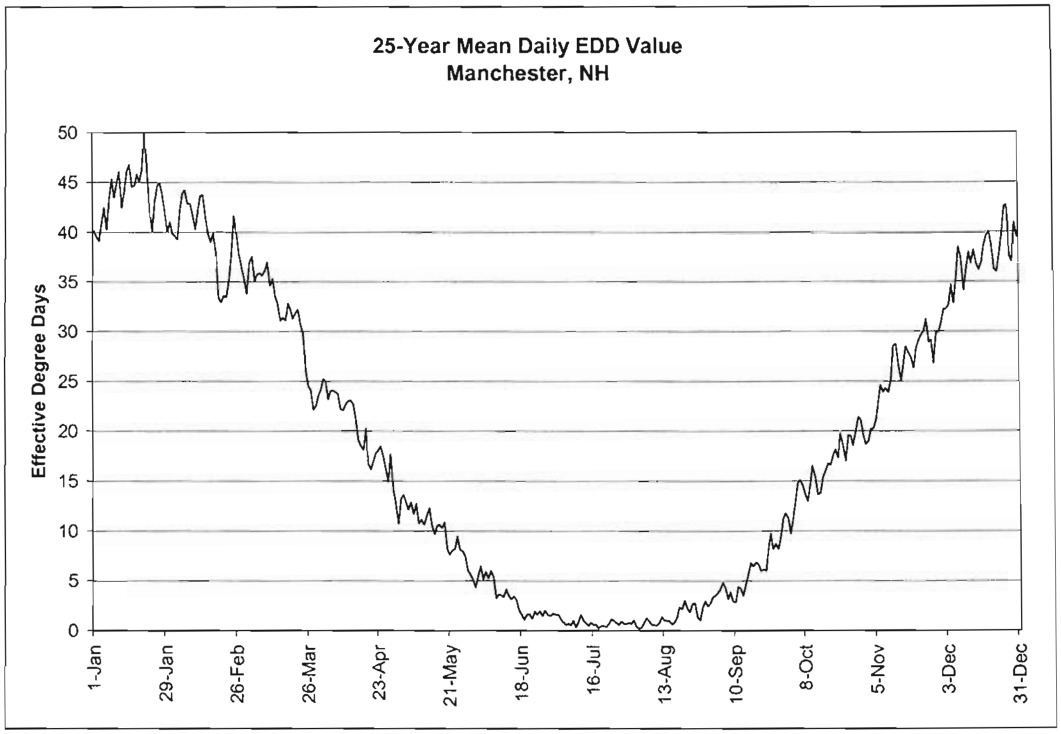


Figure 1: 25-Year Mean Observed EDD Value By Calendar Day

To calculate its synthetic EDD series, the Company first divided its process into two subsets: heating season (October-May) and non-heating season (June-September). This was necessary to properly account for the fact that EDD values are not a continuous number series, i.e. while, theoretically EDD values can grow infinitely positive, by definition, they have a lower limit of zero.

d. The Application of the Company's Monte Carlo Methodology: Heating Season

For each day of observed EDD for the heating season, the Company then computed the difference from that day's actual EDD and the 25-year mean EDD value for the same calendar day. From these daily deviation values, the Company calculated mean and standard deviation values, for each calendar month, to establish the μ and σ^2 parameters required for its AR(1) process. From the time series of these daily deviation values, the Company calculated Pearson correlation coefficient, for each calendar month, to establish the Φ parameter required for its AR(1) process.

	μ	Σ	Φ
October	0.00	7.17	0.541
November	0.00	8.68	0.536
December	0.00	9.86	0.631
January	0.00	11.54	0.671
February	0.00	10.10	0.618
March	0.00	8.65	0.583
April	0.00	7.61	0.555
May	0.00	5.91	0.499

Table 1: μ, Φ and σ^2 parameters for the AR(1) heating season process

To create 3,000 years of synthetic daily EDD time series, the Company generated 243 random EDD deviation values (October 1^{st} – May 31^{st}) denoted by X'_1, $X'_2, \ldots, X'_n$, from the AR(1) process and added each day's deviation to the established mean EDD value for the same calendar day. The initial daily EDD deviation value (for the day of October 1^{st}), X'_1 was produced from the $N(\mu, \sigma^2)$ normal distribution by means of a random number generator. Each subsequent daily EDD deviation value, $X'_{n,}$ was produced using Equations (1) and (2) from the $N(\mu, \sigma^2)$ normal distribution by means of a random number generator and the first-order autocorrelation coefficient Φ.

e. The Application of the Company's Monte Carlo Methodology: Non-Heating Season

To account for the fact that EDD values will frequently be zero during the non-heating season months of June through September, the Company modified the approach for the heating season and determined the actual monthly values of μ and σ, by matching the tail end of each month's actual observed distribution over the 25-year historical period with a normal distribution. Therefore, the Company could bypass the step of applying random errors to the 25-year mean EDD value for each calendar day and generate the synthetic values themselves with the and σ values and the monthly Pearson correlation coefficients of the deviation-from-mean values.

	μ	Σ	Φ
June	1.00	5.50	0.541
July	-1.50	3.00	0.536
August	-1.20	4.50	0.631
September	4.50	6.50	0.671

Table 2: μ, Φ and σ^2 parameters for the AR(1) non-heating season process

To create 3,000 years of synthetic daily EDD time series, the Company generated 122 random EDD values (June 1st – September 30th) denoted by X'_1, X'_2,..., X'_n, from the AR(1) process. The initial daily EDD value (for the day of June 1st), X'_1 was produced from the $N(\mu, \sigma^2)$ normal distribution by means of a random number generator. Each subsequent daily EDD value, X'_n, was produced using Equations (1) and (2) from the $N(\mu, \sigma^2)$ normal distribution by means of a random number generator and the first-order autocorrelation coefficient Φ.

f. Results of the Company's Monte Carlo Methodology: Peak Day

For each of the 3,000 synthetic heating seasons (October-May), the greatest EDD value was selected, with the minimum value of 52 EDD, the maximum value of 95 EDD, the mean value of 66.98 EDD and the standard deviation of 5.99 EDD. These statistics can be compared to the actual observed values from 1981-2005: the minimum value of 55 EDD, the maximum value of 80 EDD, the mean value of 68 EDD and the standard deviation of 6.39 EDD.

Table 3 below lists the EDD values from 67 through 90, along with the number of occurrences exceeding each EDD value, and the probability of exceeding each EDD value, based on the synthetic dataset.

Greatest Heating Season EDD Value	Number of Occurrences Exceeding	Probability of Exceeding
67	1,288	0.4293
68	1,088	0.3627
69	903	0.3010
70	769	0.2563
71	631	0.2103
72	503	0.1677
73	403	0.1343
74	323	0.1077
75	264	0.0880
76	207	0.0690
77	163	0.0543
78	125	0.0417
79	93	0.0310
80	74	0.0247
81	57	0.0190
82	43	0.0143
83	29	0.0097
84	24	0.0080
85	16	0.0053
86	11	0.0037
87	8	0.0027
88	3	0.0010
89	3	0.0010
90	3	0.0010

Table 3: Peak Day Results Generated From Synthetic Dataset

g. Results of the Company's Monte Carlo Methodology: Peak Years

For each of the 3,000 synthetic years, the annual total EDDs were calculated, with the minimum value of 6,021 EDD, the maximum value of 8,081 EDD, the mean value of 7,079 EDD and the standard deviation of 291.29 EDD. These statistics can be compared to the actual observed calendar year values from 1981-2005: the minimum value of 6,450 EDD, the maximum value of 7,700 EDD, the mean value of 7,108 EDD and the standard deviation of 332.38 EDD.

Table 4 below lists the EDD values from 7,100 through 8,300, along with the number of occurrences exceeding each EDD value, and the probability of exceeding each EDD value, based on the synthetic dataset.

Greatest Annual EDD Value	Number of Occurrences Exceeding	Probability of Exceeding
7,100	1,401	0.4670
7,200	989	0.3297
7,300	650	0.2167
7,400	396	0.1320
7,500	220	0.0733
7,600	113	0.0377
7,700	51	0.0170
7,800	15	0.0050
7,900	5	0.0017
8,000	3	0.0010
8,100	0	0.0000
8,200	0	0.0000
8,300	0	0.0000

Table 4: Peak Year Results Generated From Synthetic Dataset

The Company then proceeded to use the 'Probability of Exceeding' values from its synthetic dataset in its cost/benefit analyses of Design Day and Design Year determination.

2. Normal Year Standards

From Section III.C.1.g above, it was determined that the normal year is 7,079 EDD with a standard deviation of 291.29 EDD

EnergyNorth then prepared a "Typical Meteorological Year" (Chart III-E-1) by selecting, for each calendar month, the month in the Manchester, NH weather database that most closely approximated the average EDD and standard deviation for each month.

3. Design Year and Design Day Planning Standards

EnergyNorth's planning standards represent the defined weather conditions and consequent sendout requirement that must be met by the Company's resource portfolio. EnergyNorth's design year and design day standards are listed in Chart III-E-2.

Because EnergyNorth must demonstrate that there are adequate resources available to meet design conditions, while minimizing costs in a normal year, the Company periodically reassesses the appropriateness of these standards. As described below, the Company's analysis of the design year and design day standards demonstrate that these standards are appropriate.

(a) Design Day Standard

The purpose of a design day standard is to establish the amount of system-wide throughput (interstate pipeline and underground-storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system. In this filing, EnergyNorth defines its design day standard as 80.2 EDD with a probability of occurrence of once in 42.49 years.

EnergyNorth established its design day standard using a three-step process. First, the Company performed a statistical analysis of the coldest days derived from its Monte Carlo analysis. Second, the Company conducted a cost-benefit analysis to evaluate the cost of maintaining the resources necessary to meet design day demand versus the cost to customers of experiencing service curtailments. Third, the Company identified a design-day standard that would maintain reliability at the lowest cost.

For the first step, Section III.C.1.f (above), the Company identified the probability of occurrence of the coldest day of a heating season.

For the second step, EnergyNorth examined the cost of potential customer curtailments through a cost-benefit analysis. Chart III-E-3 shows the cumulative probability distribution and the frequency of occurrence of EDD levels greater than the mean peak day. Chart III-E-3 also shows, given the peak period heating coefficient of 1,463 MMBtu/EDD, the supply ("Delta Supply") required at these levels. The Company then translated these supply levels into the "Equivalent Number of Customers" that would be represented by a shortfall at a given EDD level.[9]

[9] EnergyNorth determined the equivalent number of customers using the following formula: Delta Supply/[(Heating Increment/Number of Customers)*EDD].

In the event of a service disruption, there are several types of damages that customers could experience. For example, EnergyNorth's residential customers would potentially incur re-light costs and freeze-up damages. EnergyNorth's commercial/industrial customers would potentially incur economic damages associated with the loss of production on the day of the event (which is further documented in Section III.E.2(b) - Design Year Standard).

There are three potential re-light cost values for three different building densities where the re-lights may occur: (1) congested areas; (2) moderately congested areas; and (3) non-congested areas. The re-lighting cost per establishment rises as the building density decreases to account for the increased time that is required to travel between establishments. The cost estimate for moderately congested areas was chosen as representative for EnergyNorth's planning standards.

EnergyNorth obtained a cost estimate for freeze-up damages from KeySpan's Risk Management Group. The current cost estimate of remodeling is $44,631/customer. The Company made the assumption that, in the event of freeze-up damages, only a portion of a residence would require remodeling. This provides a range of possible outcomes, due to the uncertainty of what might occur in the event of such freeze-ups. Accordingly, the Company used this cost estimate to represent the cost of a full remodel, which was then adjusted to represent the portion of the residence requiring remodeling.

Given the ratio of C&I customers to the total number of customers at year-end 2005, EnergyNorth divided the "Equivalent Number of Customers" into the number of residential and C&I customers. For the C&I customers, the Company computed the cost of the service disruption by multiplying the ratio of affected customers by the total number of C&I customers by the estimated cost of one day's service disruption to EnergyNorth's entire group of C&I customers. Since the actual number of residential customers that would suffer freeze-up damage in a real emergency is unknown, EnergyNorth analyzed three levels of damages assuming 25 percent, 50 percent, and 75 percent of potentially-affected residential customers suffer damages. The computed values for these three scenarios of probability-weighted costs of damages are presented in Chart III-E-4 and are shown graphically in Chart III-E-5.

Chart III-E-6 takes the EDD levels and the associated Delta Supply (i.e. the implicit supply shortfall – the EDDs above the mean peak day value times the overall heating increment) to estimate the costs associated with maintaining adequate deliverability at the EDD levels. The low-upgrade cost scenario is based on the cost of adding propane vaporization capacity and the high—upgrade cost scenario is based on the cost of adding 365-day interstate pipeline service (with many other potential options falling in between). This is shown graphically in Chart III-E-7. In Chart III-E-7, the cost of maintaining adequate throughput capacity and the benefit of avoiding damage costs that would be incurred in relation customer premises are compared.

The intersection of the curves sets a range of solutions for design day planning purposes from approximately 75 to 87 EDD with the center of the geometric shape located at 80.2 EDD. The Company then rounded this to the nearest integer value (80 EDD).

(b) Design Year Standard

In this filing, EnergyNorth defines its design year standard as 7,680 EDD with a probability of occurrence of once in 47.32 years.

EnergyNorth maintains a design year standard for planning purposes to identify the amount of seasonal supplies of natural gas that will be required to provide continuous service under all reasonably anticipated weather conditions. If EnergyNorth were to have a shortfall in supply during the winter season, the amount of supply in deficit can be translated into an equivalent number of customers whose service would be disrupted for more than one day. For a supply disruption of a multi-day duration, service would be curtailed on a priority basis and would likely fall on commercial and industrial establishments before affecting the residential sector, since supply to the residential sector is more likely to involve health and personal safety concerns. To establish an estimated annual level of EDD for which EnergyNorth should plan, the Company compared the benefit of maintaining an adequate quantity of natural gas supply under all reasonably anticipated weather conditions to the probability-weighted cost of losses that might occur if supplies are not adequate.

EnergyNorth has established its design-year standard using a three-step process. First, the Company performed a statistical analysis of annual EDD data recorded over a historical period. Second, the Company conducted a cost-benefit analysis to evaluate the cost of maintaining the resources necessary to meet design-year demand versus the cost to customers of experiencing service curtailments. Third, the Company identified a design-year standard that would maintain reliability at the lowest cost.

To complete the first step in the process of determining EnergyNorth's design-year standard, the Company relied on the results of its Monte Carlo analysis as found in Section III.C.1.g above. To evaluate the design-year standard, EnergyNorth analyzed a range of annual EDD values from the mean value to 1,200 EDD greater than the mean.

To complete the second step in the development of the design-year standard, EnergyNorth performed a cost-benefit analysis by examining the cost of potential customer curtailments in relation to the cost of maintaining adequate supplies to meet the design-year standard. Because a failure to perform on a seasonal basis would mean that adequate supplies were not available to meet customer needs, EnergyNorth views the cost of failure to deliver as the economic penalty within the service territory associated with the need to curtail gas sales for a period of time. Service would be rationed among EnergyNorth customers for a number of days in order to preserve any remaining gas supplies. EnergyNorth estimated the potential losses based on the product of the potential economic cost per day of interruption, times the number of days of interruption.

To calculate this estimate of potential losses, EnergyNorth determined the average Gross State Product per day (GSP/day) for the state of New Hampshire for 2005 from data available from the U.S. Bureau of Economic Analysis. The economic cost to EnergyNorth's customer base per day was then calculated on the basis of the total GSP/day. First, the value for the GSP/day for EnergyNorth's service territory was estimated by multiplying the GSP/day by the ratio of the number of employees within the service territory to the total number of employees within the state, based on 2005 employment data from the New Hampshire Economic and Labor Market Information

Bureau. Then, the value for the GSP/day in 2005 for EnergyNorth's customer base was estimated by multiplying the GSP/day figure for the EnergyNorth service territory by the estimated market share of natural gas in relation to all fuel types in the service territory.

To determine the number of days of interruption that a supply shortfall would represent, EnergyNorth analyzed its supply requirements at various EDD levels, assigned requirements to supply sources, and, using the average annual EDD as the baseline, estimated when supply sources would be in deficit, as well as the quantity and duration of such deficit.

EnergyNorth established a baseline of the normal annual EDD (7,079) and then determined sendout requirements for the split year 2005/06 by assigning all sendout requirements below the daily deliverability of its Canadian and domestic long-haul pipeline capacity to pipeline supply; all requirements greater than its pipeline supply up to its underground storage deliverability to underground storage supplies; and all requirements above that to supplemental resources. EnergyNorth then analyzed the sendout requirements for EDD levels of 7,079 to 8,300 on 100 EDD increments. EnergyNorth computed these EDD scenarios by multiplying each of the days of its normal EDD days by the ratio of the desired annual total to 7,079 EDD. Using the same method of assignment of supply sources, EnergyNorth determined the annual shortfalls by supply source (Chart III-E-8).

Chart III-E-9 shows that the timing of when the shortfalls occur varies among the supply sources. Pipeline shortfalls occur late in the heating season. The underground storage and supplemental-resource shortfalls occur during the heating season. Chart

III-E-10 summarizes the EDD levels, the probabilities of occurrence, and the shortfall by supply type.

Analysis indicates that sendout for EnergyNorth during the heating season is 49 percent residential and 51 percent C&I. In examining its calculations of shortfalls versus the daily sendout requirements to each of these customer classes, the total daily shortfall of underground storage and supplemental supplies at all EDD levels in this study can be assigned to C&I customers. For each forecast day under each EDD scenario, the daily sendout requirement was multiplied by 51 percent to derive the C&I portion. If the day had a supply shortfall, the shortfall value was divided by the C&I requirement to derive that day's fractional amount of EnergyNorth's C&I customers that would suffer curtailment. Summing all of these values for a given EDD scenario, EnergyNorth determined the total number of day-equivalents of interruption. This value is less than or equal to the number of calendar days during which interruption occurred since not all days will have 100 percent interruption. Multiplying the number of day-equivalents by the GSP/day for the C&I customer base yields an estimate of the economic damage that would occur. Chart III-E-11 lists the EDD levels, the probabilities of occurrence, the days of interruption, the cost of the interruption, the probability-weighted cost of the interruption, and the quantity of interrupted winter supply (underground storage and supplemental resources).

There are two damages scenarios presented here: one where 25 percent of the C&I establishments are actually affected, and one where 75 percent of the establishments are affected. Chart III-E-11 also sets forth two scenarios of satisfying the deficit: a 365-day long-haul capacity contract based on the required incremental throughput capacity, and a 365-day short-haul capacity contract meeting the required incremental throughput capacity plus an underground storage contract with adequate capacity to meet the required incremental winter volume. Chart III-E-12 demonstrates that a planning range of 7,590 to 7,740 EDD, with the center of the geometric shape located at 7,680 EDD is appropriate.

F. Forecasts of Design Year Customer Requirements By Year

In the fifth and final step of the Company's forecasting methodology set forth in Section III.A above, the Company uses the applicable design day and design year planning standards to determine the design day and design year sendout requirements. To accomplish this, the Company combines the 2005/06 reference-year sendout, which is derived from the regression analysis, with the annual incremental sendout forecast discussed in Section III.B, to yield the following forecast of customer requirements under design weather conditions:

Base Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	**2007-08**	**2008-09**	**2009-10**	**2010-11**
Heating Season	10,451,700	10,795,100	10,946,700	11,183,400	11,452,000
Non-Heating Season	4,089,700	4,232,000	4,350,800	4,475,400	4,617,800
Total	14,541,400	15,027,100	15,297,500	15,658,800	16,069,800
Per-Annum Growth		3.3 %	1.8 %	2.4 %	2.6 %

High Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	**2007-08**	**2008-09**	**2009-10**	**2010-11**
Heating Season	10,764,700	11,221,900	11,458,800	11,786,400	12,147,900
Non-Heating Season	4,264,200	4,469,300	4,638,200	4,814,700	5,009,900
Total	15,028,900	15,691,200	16,097,000	16,601,100	17,157,800
Per-Annum Growth		4.4 %	2.6 %	3.1 %	3.4 %

Low Case Demand Scenario Customer Requirements (MMBtu)

	2006-07	2007-08	2008-09	2009-10	2010-11
Heating Season	10,123,200	10,358,400	10,430,400	10,582,000	10,765,200
Non-Heating Season	3,904,200	3,983,100	4,051,700	4,124,400	4,213,500
Total	14,027,400	14,341,500	14,482,100	14,706,400	14,978,700
Per-Annum Growth		2.2 %	1.0 %	1.5 %	1.9 %

KeySpan Sendout Requirements Forecast
EnergyNorth Natural Gas, Inc.
2006/07 - 2010/11 Base Case

Normal Weather	2006/07	2007/08	2008/09	2009/10	2010/11	Average Increment Or Percent	Total Increment Or Percent
Sendout (MMBtu)							
Residential	5,804,058	6,012,112	6,136,364	6,253,751	6,387,670	145,903	583,612
Commercial & Industrial	7,450,242	7,695,788	7,832,536	8,056,549	8,311,430	215,297	861,188
Traditional Market	13,254,300	13,707,900	13,968,900	14,310,300	14,699,100	361,200	1,444,800
NGV	0	0	0	0	0	0	0
Seasonal	0	0	0	0	0	0	0
Total	13,254,300	13,707,900	13,968,900	14,310,300	14,699,100	361,200	1,444,800
Growth Rate (%)							
Residential		3.58%	2.07%	1.91%	2.14%	2.43%	9.71%
Commercial & Industrial		3.30%	1.78%	2.86%	3.16%	2.77%	11.10%
Traditional Market		3.42%	1.90%	2.44%	2.72%	2.62%	10.49%
NGV		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Seasonal		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total		3.42%	1.90%	2.44%	2.72%	2.62%	10.49%

Design Weather	2006/07	2007/08	2008/09	2009/10	2010/11	Average Increment Or Percent	Total Increment Or Percent
Sendout (MMBtu)							
Residential	6,367,679	6,590,696	6,720,001	6,843,060	6,983,324	153,911	615,645
Commercial & Industrial	8,173,721	8,436,404	8,577,499	8,815,740	9,086,476	228,189	912,755
Traditional Market	14,541,400	15,027,100	15,297,500	15,658,800	16,069,800	382,100	1,528,400
NGV	0	0	0	0	0	0	0
Seasonal	0	0	0	0	0	0	0
Total	14,541,400	15,027,100	15,297,500	15,658,800	16,069,800	382,100	1,528,400
Growth Rate (%)							
Residential		3.50%	1.96%	1.83%	2.05%	2.34%	9.35%
Commercial & Industrial		3.21%	1.67%	2.78%	3.07%	2.68%	10.73%
Traditional Market		3.34%	1.80%	2.36%	2.62%	2.53%	10.13%
NGV		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Seasonal		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total		3.34%	1.80%	2.36%	2.62%	2.53%	10.13%

EnergyNorth Natural Gas, Inc.
d/b/a KeySpan Energy Delivery New England
Demand Projections
Base Case
2006-2010
(MMBtu)

TOTAL ANNUAL LOAD ADDITIONS (2006-2010)
2006 FORECAST

	2007-2008	2008-2009	2009-2010	2010-2011	Total	Annual Average
NET ANNUAL ADDITIONS						
Residential	198,849	176,048	139,114	155,256	669,267	167,317
DSM Reduction	(24,005)	(24,005)	(24,005)	(24,005)	(96,020)	(24,005)
Total Residential	174,844	152,043	115,109	131,251	573,247	143,312
Commercial/Industrial	259,919	220,901	273,234	303,371	1,057,425	264,356
DSM Reduction	(53,568)	(53,568)	(53,568)	(53,568)	(214,272)	(53,568)
Total Commercial/Industrial	206,351	167,333	219,666	249,803	843,153	210,788
Traditional Total	381,195	319,376	334,775	381,054	1,416,400	354,100
Natural Gas Vehicles	0	0	0	0	0	0
Seasonal Firm Contracts	0	0	0	0	0	0
TOTAL NET	381,195	319,376	334,775	381,054	1,416,400	354,100

EnergyNorth Natural Gas, Inc.
d/b/a KeySpan Energy Delivery New England
Demand Projections
Base Case vs. Low Case and High Case
2006-2010
(MMBtu)

TOTAL ANNUAL LOAD ADDITIONS (2006-2010)
2006 FORECAST

		2007-2008	2008-2009	2009-2010	2010-2011	Total	Annual Average
NET ANNUAL ADDITIONS							
Base Case vs Low Case							
	Base Case						
	Residential	174,844	152,043	115,109	131,251	573,247	143,312
	Commercial/Industrial	206,351	167,333	219,666	249,803	843,153	210,788
	Traditional Total	381,195	319,376	334,775	381,054	1,416,400	354,100
	Low Case						
	Residential	161,170	140,073	100,844	113,637	515,723	128,931
	Commercial/Industrial	62,664	55,312	106,050	137,571	361,599	90,400
	Traditional Total	223,834	195,385	206,894	251,208	877,322	219,330
	Difference (Base vs. Low)						
	Residential	13,674	11,970	14,266	17,615	57,524	14,381
	Commercial/Industrial	143,687	112,021	113,616	112,231	481,554	120,389
	Traditional Total	157,360	123,991	127,881	129,846	539,078	134,770
	Difference as % of Base Case						
	Residential	7.82%	7.87%	12.39%	13.42%	10.03%	10.03%
	Commercial/Industrial	69.63%	66.94%	51.72%	44.93%	57.11%	57.11%
	Traditional Total	41.28%	38.82%	38.20%	34.08%	38.06%	38.06%
Base Case vs High Case							
	Base Case						
	Residential	174,844	152,043	115,109	131,251	573,247	143,312
	Commercial/Industrial	206,351	167,333	219,666	249,803	843,153	210,788
	Traditional Total	381,195	319,376	334,775	381,054	1,416,400	354,100
	High Case						
	Residential	190,133	165,488	131,184	151,023	637,828	159,457
	Commercial/Industrial	353,008	282,460	336,395	365,553	1,337,415	334,354
	Traditional Total	543,140	447,948	467,580	516,576	1,975,243	493,811
	Base vs. High						
	Residential	(15,289)	(13,445)	(16,075)	(19,772)	(64,581)	(16,145)
	Commercial/Industrial	(146,656)	(115,127)	(116,729)	(115,750)	(494,262)	(123,566)
	Traditional Total	(161,946)	(128,572)	(132,804)	(135,522)	(558,843)	(139,711)
	% of Base Case						
	Residential	-8.74%	-8.84%	-13.97%	-15.06%	-11.27%	-11.27%
	Commercial/Industrial	-71.07%	-68.80%	-53.14%	-46.34%	-58.62%	-58.62%
	Traditional Total	-42.48%	-40.26%	-39.67%	-35.56%	-39.46%	-39.46%

EnergyNorth Natural Gas, Inc.
d/b/a KeySpan Energy Delivery New England
Demand Projections
High Case
2006-2010
(MMBtu)

TOTAL ANNUAL LOAD ADDITIONS (2006-2010)
2006 FORECAST

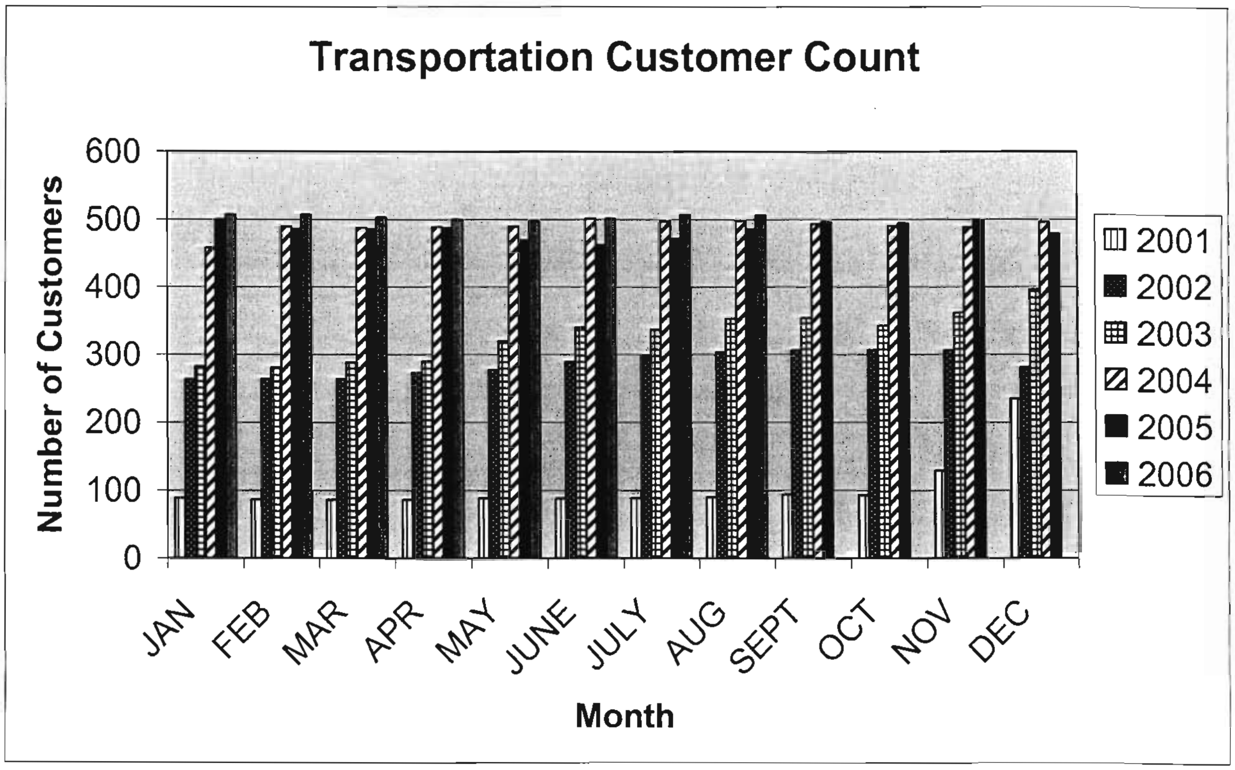
	2007-2008	2008-2009	2009-2010	2010-2011	Total	Annual Average
NET ANNUAL ADDITIONS						
Residential	214,138	189,493	155,189	175,028	733,848	183,462
DSM Reduction	(24,005)	(24,005)	(24,005)	(24,005)	(96,020)	(24,005)
Total Residential	190,133	165,488	131,184	151,023	637,828	159,457
Commercial/Industrial	406,576	336,028	389,963	419,121	1,551,687	387,922
DSM Reduction	(53,568)	(53,568)	(53,568)	(53,568)	(214,272)	(53,568)
Total Commercial/Industrial	353,008	282,460	336,395	365,553	1,337,415	334,354
Traditional Total	543,140	447,948	467,580	516,576	1,975,243	493,811
Natural Gas Vehicles	0	0	0	0	0	0
Seasonal Firm Contracts	0	0	0	0	0	0
TOTAL NET	543,140	447,948	467,580	516,576	1,975,243	493,811

EnergyNorth Natural Gas, Inc.
d/b/a KeySpan Energy Delivery New England
Demand Projections
Low Case
2006-2010
(MMBtu)

TOTAL ANNUAL LOAD ADDITIONS (2006-2010)
2006 FORECAST

	2007-2008	2008-2009	2009-2010	2010-2011	Total	Annual Average
NET ANNUAL ADDITIONS						
Residential	185,175	164,078	124,849	137,642	611,743	152,936
DSM Reduction	(24,005)	(24,005)	(24,005)	(24,005)	(96,020)	(24,005)
Total Residential	161,170	140,073	100,844	113,637	515,723	128,931
Commercial/Industrial	116,232	108,880	159,618	191,139	575,871	143,968
DSM Reduction	(53,568)	(53,568)	(53,568)	(53,568)	(214,272)	(53,568)
Total Commercial/Industrial	62,664	55,312	106,050	137,571	361,599	90,400
Traditional Total	223,834	195,385	206,894	251,208	877,322	219,330
Natural Gas Vehicles	0	0	0	0	0	0
Seasonal Firm Contracts	0	0	0	0	0	0
TOTAL NET	223,834	195,385	206,894	251,208	877,322	219,330

Chart III-B-5



Transportation Customer Count
600
500
400
300
200
100
0
Number of Customers
JAN
FEB
MAR
APR
MAY
JUNE
JULY
AUG
SEPT
OCT
NOV
DEC
Month
2001
2002
2003
2004
2005
2006

Chart III-B-6

KeySpan Energy Delivery
Energy North
Marketer Underdeliveries
Peak Season Periods
Nov 03 - Mar 04

(MMBtu)

Marketer:	Daily Metered Service A	B	C	D	E	F	Total Under-Deliv	Total Marketer Deliveries	% Imbalance	Non-Daily Metered Service A	B	C	D	E	F	Total Under-Deliv	Total Marketer Deliveries	% Imbalance
Imbalance Date																		
11/6/2003	0	144	0	0	0	0	144	5,199	2.77%	0	0	0	0	0	0	0	n/a	n/a
11/10/2003	0	169	0	0	0	0	169	6,566	2.57%	0	0	0	0	0	0	0	n/a	n/a
11/11/2003	0	197	0	0	0	0	197	6,240	3.16%	0	0	0	0	0	0	0	n/a	n/a
11/18/2003	0	1	0	0	0	0	1	6,847	0.01%	0	0	0	0	0	0	0	n/a	n/a
12/1/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	0	7	0	7	2,318	0.30%
12/2/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	0	6	0	6	2,929	0.20%
12/3/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	0	3	0	3	2,781	0.11%
12/4/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	0	30	0	30	2,742	1.09%
12/5/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	0	30	0	30	2,552	1.18%
12/25/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	48	0	0	48	2,365	2.03%
12/26/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	14	0	0	14	2,688	0.52%
12/27/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	12	0	0	12	2,690	0.45%
12/28/2003	0	0	0	0	0	0	0	n/a	n/a	0	0	0	11	0	0	11	2,633	0.42%
1/1/2004	0	0	0	36	83	282	401	3,792	10.57%	0	0	0	0	0	0	0	n/a	n/a
1/4/2004	0	1	0	0	0	0	1	5,262	0.02%	0	0	0	0	0	0	0	n/a	n/a
1/5/2004	0	0	0	1	0	0	1	6,639	0.02%	0	0	0	0	0	0	0	n/a	n/a
1/10/2004	0	0	0	0	0	0	0	n/a	n/a	0	0	0	11	8	0	19	4,757	0.40%
1/24/2004	0	0	0	0	0	0	0	n/a	n/a	0	1	0	0	0	0	1	4,518	0.02%
1/27/2004	0	4	0	0	0	0	4	178	2.25%	0	0	0	0	0	0	0	n/a	n/a
1/28/2004	0	2	0	0	0	0	2	7,721	0.03%	0	0	0	0	0	0	0	n/a	n/a
1/29/2004	0	0	0	0	41	0	41	7,616	0.54%	0	0	0	0	0	0	0	n/a	n/a
1/31/2004	0	0	0	26	0	0	26	6,419	0.41%	0	0	0	0	0	0	0	n/a	n/a
2/3/2004	0	0	0	0	0	0	0	n/a	n/a	n/a	0	0	284	0	0	284	2,609	10.89%
2/12/2004	0	2	0	0	0	0	2	7,284	0.03%	n/a	0	0	0	0	0	0	n/a	n/a
2/16/2004	0	6	0	0	0	0	6	8,065	0.07%	n/a	0	0	0	0	0	0	n/a	n/a
2/17/2004	36	1	0	25	28	0	90	7,173	1.25%	n/a	0	0	0	0	0	0	n/a	n/a
2/20/2004	0	5	0	0	0	0	5	6,031	0.08%	n/a	0	0	0	0	0	0	n/a	n/a
2/22/2004	0	1	0	0	0	0	1	6,606	0.02%	n/a	0	0	0	0	0	0	n/a	n/a
3/8/2004	0	6	0	0	0	0	6	6,780	0.09%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/10/2004	0	6	0	0	0	0	6	6,625	0.09%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/12/2004	0	3	0	0	0	0	3	6,605	0.05%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/13/2004	0	4	0	0	0	0	4	6,198	0.06%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/19/2004	0	2	0	0	0	0	2	6,746	0.03%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/21/2004	0	2	0	0	0	0	2	6,008	0.03%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/22/2004	0	12	0	0	0	0	12	7,221	0.17%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/23/2004	0	12	0	0	0	0	12	6,984	0.17%	n/a	n/a	0	0	0	0	0	n/a	n/a
3/24/2004	0	9	0	0	0	0	9	6,490	0.14%	n/a	n/a	0	0	0	0	0	n/a	n/a
Total Nov 03 - Mar 04	36	589	0	88	152	282	1,147	157,295	0.73%	0	1	0	380	84	0	465	35,582	1.31%

Underdeliveries are imbalances where marketer has been assessed a penalty charge for underdeliveries outside
of the respective peak season tolerances. There were no penalties assessed for underdeliveries during Critical Day/OFO periods.

KeySpan Energy Delivery

Energy North

Marketer Underdeliveries

Peak Season Periods

Nov 04 - Mar 05

(MMBtu)

	Daily Metered Service										Non-Daily Metered Service									
								Total	Total									Total	Total	
								Under-	Marketer	%								Under-	Marketer	%
Marketer:	A	B	C	D	E	F	G	Deliv	Deliveries	Imbalance	A	B	C	D	E	F	G	Deliv	Deliveries	Imbalance
Imbalance Date																				
11/9/2004	n/a	n/a	0	1	72	0	0	73	6,959	1.05%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/5/2004	n/a	n/a	34	57	228	33	0	352	5,275	6.67%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/7/2004	n/a	n/a	5	48	0	0	0	53	6,395	0.83%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/20/2004	n/a	n/a	0	39	0	105	0	144	7,697	1.87%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/21/2004	n/a	n/a	0	62	0	79	0	141	7,206	1.96%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
1/12/2005	n/a	n/a	0	46	237	0	0	283	5,834	4.85%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
1/31/2005	n/a	n/a	0	0	40	0	0	40	6,895	0.58%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
Total Nov 04 - Mar 05	n/a	n/a	39	253	577	217	0	1,086	46,261	2.35%	n/a	n/a	0	0	0	0	0	0	n/a	n/a

Underdeliveries are imbalances where marketer has been assessed a penalty charge for underdeliveries outside of the respective peak season tolerances. There were no penalties assessed for underdeliveries during Critical Day/OFO periods.

KeySpan Energy Delivery

Energy North

Marketer Underdeliveries

Peak Season Periods

Nov 05 - Mar 06

(MMBtu)

	Daily Metered Service										Non-Daily Metered Service									
								Total Under-Deliv	Total Marketer Deliveries	% Imbalance								Total Under-Deliv	Total Marketer Deliveries	% Imbalance
Marketer:	A	B	C	D	E	F	G				A	B	C	D	E	F	G			
Imbalance Date																				
11/2/2005	n/a	n/a	0	68	0	0	0	68	6,758	1.01%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
11/11/2005	n/a	n/a	0	69	0	0	0	69	6,232	1.11%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
11/12/2005	n/a	n/a	0	49	0	0	0	49	4,430	1.11%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
11/24/2005	n/a	n/a	0	152	0	0	0	152	4,039	3.76%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
11/25/2005	n/a	n/a	0	43	0	0	0	43	4,779	0.90%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/4/2005	n/a	n/a	3	129	7	0	0	139	5,822	2.39%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
12/31/2005	n/a	n/a	0	0	0	16	0	16	4,595	0.35%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
1/1/2006	n/a	n/a	0	0	0	432	0	432	3,830	11.28%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
1/15/2006	n/a	n/a	10	58	0	210	33	311	5,637	5.52%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
2/18/2006	n/a	n/a	0	0	0	825	0	825	4,624	17.84%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
2/28/2006	n/a	n/a	0	68	0	0	0	68	7,140	0.95%	n/a	n/a	0	0	0	0	0	0	n/a	n/a
3/30/2006	n/a	n/a	0	0	0	0	0	0	n/a	n/a	n/a	n/a	0	0	0	1	0	1	1,703	0.06%
Total Nov 04 - Mar 05	n/a	n/a	13	636	7	1,483	33	2,172	57,886	3.75%	n/a	n/a	0	0	0	1	0	1	1,703	0.06%

Underdeliveries are imbalances where marketer has been assessed a penalty charge for underdeliveries outside of the respective peak season tolerances. There were no penalties assessed for underdeliveries during Critical Day/OFO periods.

Functional Form of Regression Equation

	Coefficient
Firm Sendout = f (	Base Load,
	September EDD,
	October EDD,
	November EDD,
	December EDD,
	January EDD,
	February EDD,
	March EDD,
	April EDD,
	May EDD,
	June EDD,
	Lagged EDD,
	Weekend Dummy)

In the regression equation, the units of the coefficients are in MMBtu/day for the Base Load and the Weekend Dummy and in MMBtu/EDD for the EDD-related variables.

Regression Coefficients for KeySpan

Coefficient	EnergyNorth
Base Load	9,446.702
September EDD	349.568
October EDD	896.779
November EDD	1,100.642
December EDD	1,259.716
January EDD	1,264.454
February EDD	1,251.669
March EDD	1,180.541
April EDD	926.163
May EDD	793.901
June EDD	404.185
Lagged EDD	216.750
Weekend Dummy	-2,264.001
R-squared	0.990
Std Error of the Equation	2,483.750

Chart III-E-1

Average Monthly EDD and Average of Monthly Standard Deviations For The Manchester, NH Weather Site

	EDD	Standard Deviation
January	1,348	11.0
February	1,106	10.2
March	977	9.5
April	601	8.0
May	310	6.0
June	83	3.5
July	19	1.3
August	39	2.1
September	163	5.0
October	504	7.4
November	780	9.0
December	1,149	9.7
Total	7,079	

Chart III-E-2

Design Year and Design Day Criteria

	Manchester, NH Weather Site
Design Year EDD	7,680
Frequency of Occurrence	1/47.32 years
Design Day EDD	80.2
Frequency of Occurrence	1/42.49 years

Chart III-E-3

EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Assumptions:

Mean Peak Day =	67.0 EDD
Std Dev Peak Day =	6.0 EDD
Heating Increment =	1,463 MMBtu/EDD
No. of Firm Customers =	80,303

EDD Level	Cumulative Probability Of Occurrence (p)	Probability Of Exceeding (1-p)	Frequency of Occurrence 1/(1-p) (years)	EDD Excess	Delta Supply (MMBtu)	Requirements Of An Average Customer At EDD Level (MMBtu/cust)	Equivalent Number of Customers
67.0		0.4293	2.33	0.0	23	1.22	19
68.0		0.3627	2.76	1.0	1,487	1.24	1,200
69.0		0.3010	3.32	2.0	2,950	1.26	2,346
70.0		0.2563	3.90	3.0	4,413	1.28	3,460
71.0		0.2103	4.75	4.0	5,877	1.29	4,542
72.0		0.1677	5.96	5.0	7,340	1.31	5,594
73.0		0.1343	7.44	6.0	8,803	1.33	6,618
74.0		0.1077	9.29	7.0	10,266	1.35	7,614
75.0		0.0880	11.36	8.0	11,730	1.37	8,583
76.0		0.0690	14.49	9.0	13,193	1.38	9,526
77.0		0.0543	18.40	10.0	14,656	1.40	10,446
78.0		0.0417	24.00	11.0	16,120	1.42	11,341
79.0		0.0310	32.26	12.0	17,583	1.44	12,214
80.0		0.0247	40.54	13.0	19,046	1.46	13,065
81.0		0.0190	52.63	14.0	20,509	1.48	13,895
82.0		0.0143	69.77	15.0	21,973	1.49	14,705
83.0		0.0097	103.45	16.0	23,436	1.51	15,496
84.0		0.0080	125.00	17.0	24,899	1.53	16,267
85.0		0.0053	187.50	18.0	26,363	1.55	17,020
86.0		0.0037	272.73	19.0	27,826	1.57	17,756
87.0		0.0027	375.00	20.0	29,289	1.59	18,475
88.0		0.0010	1000.00	21.0	30,753	1.60	19,178
89.0		0.0010	1000.00	22.0	32,216	1.62	19,865
90.0		0.0010	1000.00	23.0	33,679	1.64	20,536
80.2		0.0235	42.49	(EDD Level MINUS Mean Peak)	(EDD Excess TIMES Heating Increment) (MMBtu)	(Heating Increment DIVIDED BY No. of Firm Customers TIMES EDD Level)	(Delta Supply DIVIDED BY Requirements of Average Customer)

EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Assumptions:

Mean Peak Day =	67.0 EDD	
Std Dev Peak Day =	6.0 EDD	
Heating Increment =	1,463 MMBtu/EDD	
No. of Firm Customers =	80,303	
GDP Deflator (1991-2005) =	1.35	
	1991 dollars	**2005 dollars**
Relight Costs =		$80.01 /customer
Freeze-Up Damages =	$33,000.00 /customer	$44,631.19 /customer
Total =		$44,711.20 /customer
Year-End 2005:		
Comm/Ind Customers	9,640	
Total Customers	80,303	
Percent C&I of Total	12.0%	
Cost of Interruption/Day =	$27,039,948	

EDD Level	Probability Of Exceeding (1-p)	Equivalent Number of Customers	Residential Customers	Comm/Ind Customers	Cost Of Interruption to Comm/Ind Customers	Probability-Weighted Cost Of Damages Given X% of Residential Customers With Damages PLUS Cost of Interruption to Comm/Ind Customers (2005 dollars) 25%	50%	75%
67.0	0.4293	19	17	2	$6,457	83,754	164,736	245,718
68.0	0.3627	1,200	1,056	144	$404,009	4,426,492	8,706,463	12,986,435
69.0	0.3010	2,346	2,065	282	$790,037	7,184,146	14,130,491	21,076,837
70.0	0.2563	3,460	3,045	415	$1,165,035	9,022,058	17,745,478	26,468,899
71.0	0.2103	4,542	3,997	545	$1,529,471	9,718,756	19,115,814	28,512,871
72.0	0.1677	5,594	4,923	672	$1,883,783	9,541,991	18,768,134	27,994,277
73.0	0.1343	6,618	5,823	794	$2,228,388	9,043,488	17,787,630	26,531,772
74.0	0.1077	7,614	6,700	914	$2,563,679	8,338,854	16,401,685	24,464,516
75.0	0.0880	8,583	7,552	1,030	$2,890,030	7,683,274	15,112,226	22,541,178
76.0	0.0690	9,526	8,383	1,144	$3,207,792	6,686,774	13,152,210	19,617,646
77.0	0.0543	10,446	9,192	1,254	$3,517,300	5,773,473	11,355,840	16,938,207
78.0	0.0417	11,341	9,980	1,361	$3,818,873	4,807,124	9,455,128	14,103,132
79.0	0.0310	12,214	10,748	1,466	$4,112,810	3,851,782	7,576,068	11,300,353
80.0	0.0247	13,065	11,497	1,568	$4,399,399	3,278,425	6,448,331	9,618,238
81.0	0.0190	13,895	12,227	1,668	$4,678,912	2,685,715	5,282,530	7,879,346
82.0	0.0143	14,705	12,940	1,765	$4,951,608	2,144,148	4,217,324	6,290,499
83.0	0.0097	15,496	13,635	1,860	$5,217,733	1,523,772	2,997,106	4,470,439
84.0	0.0080	16,267	14,314	1,953	$5,477,521	1,323,840	2,603,859	3,883,879
85.0	0.0053	17,020	14,977	2,043	$5,731,196	923,433	1,816,300	2,709,166
86.0	0.0037	17,756	15,625	2,132	$5,978,973	662,307	1,302,691	1,943,075
87.0	0.0027	18,475	16,257	2,218	$6,221,053	501,180	985,771	1,470,362
88.0	0.0010	19,178	16,876	2,302	$6,457,631	195,090	383,722	572,354
89.0	0.0010	19,865	17,480	2,385	$6,688,893	202,076	397,464	592,851
90.0	0.0010	20,536	18,071	2,465	$6,915,016	208,908	410,901	612,893

(Probability of Exceeding TIMES
[Comm/Ind Cost of Interruption PLUS
No. Of Residential Customers TIMES Percent TIMES
Total Damage Costs])

Chart III-E-5

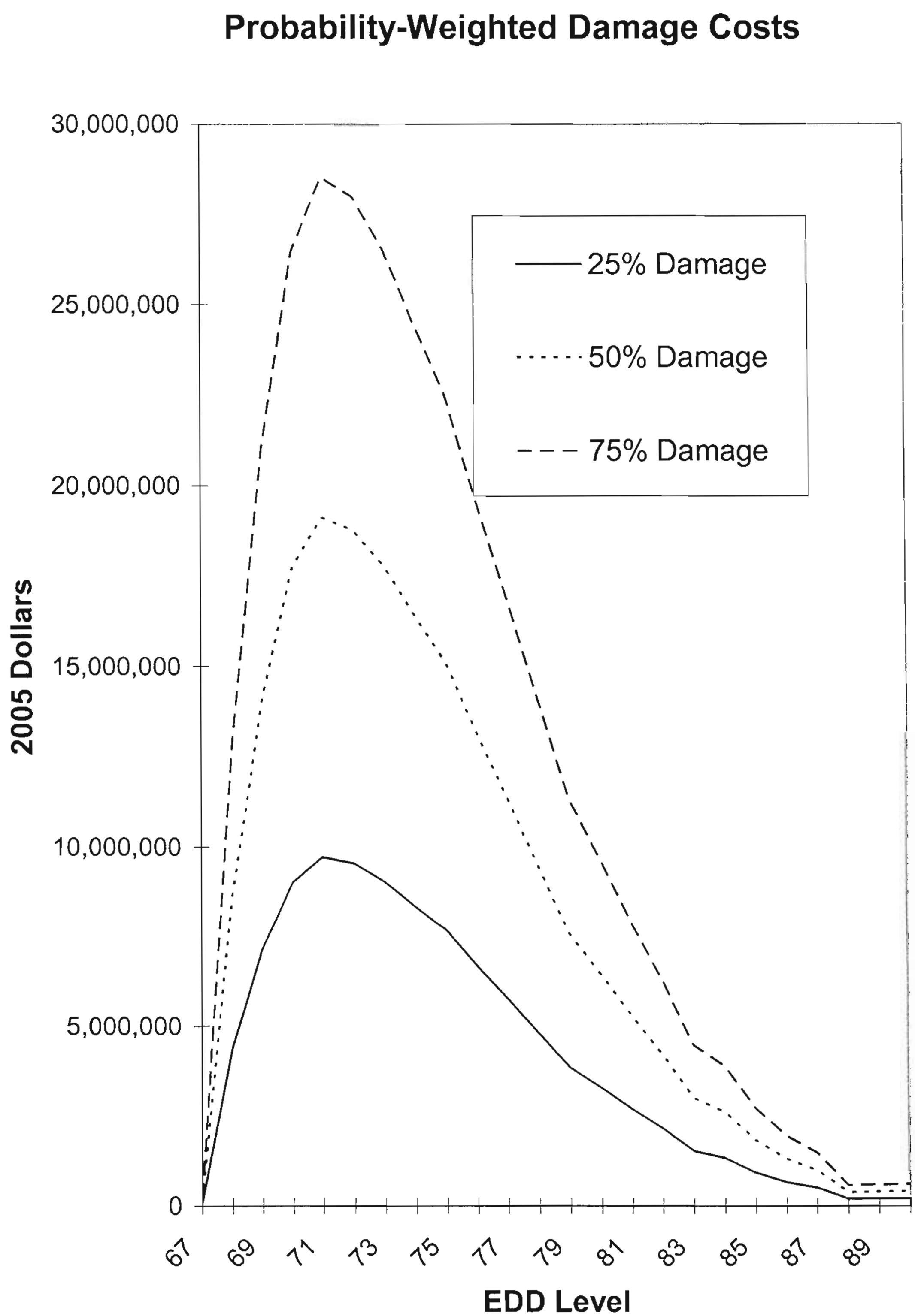

Probability-Weighted Damage Costs
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
2005 Dollars
25% Damage
50% Damage
75% Damage
67
69
71
73
75
77
79
81
83
85
87
89
EDD Level

Chart III-E-6

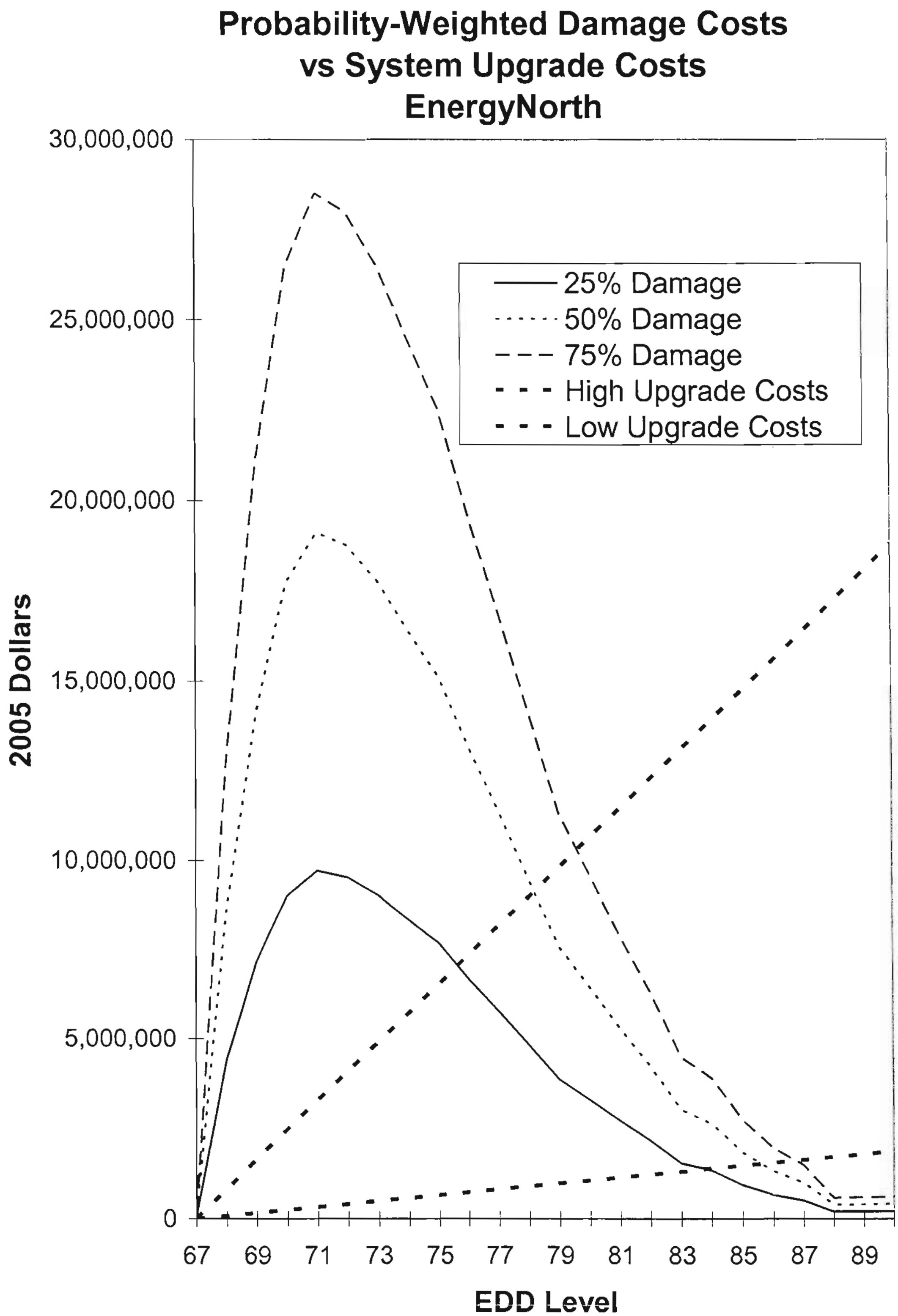
EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Assumptions:

Mean Peak Day =	67.0 EDD	
Std Dev Peak Day =	6.0 EDD	
GDP Deflator (1994-2005) =	1.26	
	1994 dollars	**2005 dollars**
Cost of Add'l Propane Capacity =	$43.86 /MMBtu	$55.40 /MMBtu
Cost of New Pipeline Capacity =	/MMBtu	$558.52 /MMBtu

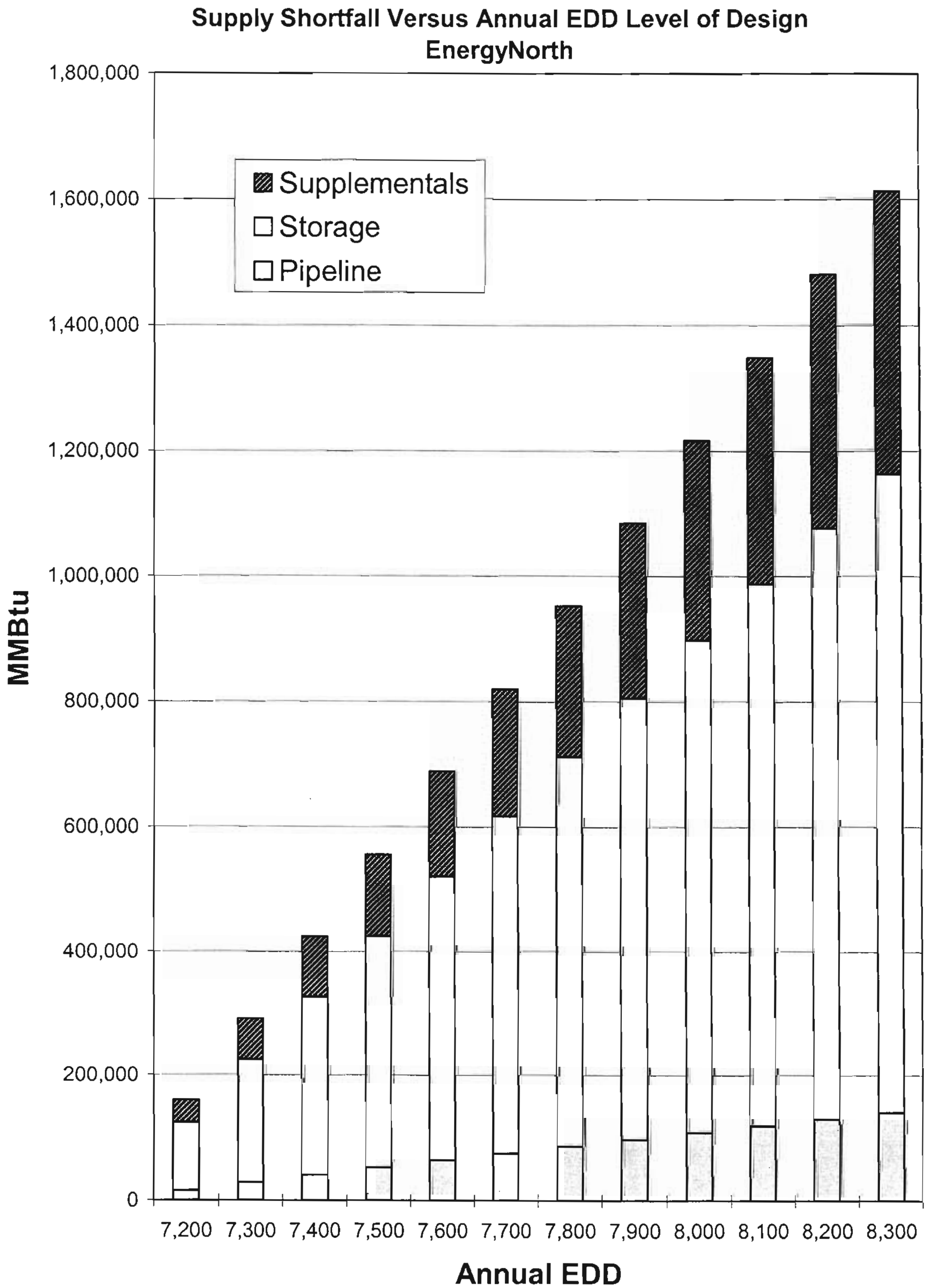
		Low Upgrade Costs Case	High Upgrade Costs Case
EDD Level	Delta Supply (MMBtu)	Propane Capacity Costs	Pipeline Capacity Costs
67.0	23	$1,297	$13,076
68.0	1,487	$82,357	$830,358
69.0	2,950	$163,417	$1,647,639
70.0	4,413	$244,477	$2,464,920
71.0	5,877	$325,537	$3,282,201
72.0	7,340	$406,596	$4,099,483
73.0	8,803	$487,656	$4,916,764
74.0	10,266	$568,716	$5,734,045
75.0	11,730	$649,776	$6,551,326
76.0	13,193	$730,836	$7,368,608
77.0	14,656	$811,896	$8,185,889
78.0	16,120	$892,956	$9,003,170
79.0	17,583	$974,016	$9,820,451
80.0	19,046	$1,055,076	$10,637,732
81.0	20,509	$1,136,136	$11,455,014
82.0	21,973	$1,217,196	$12,272,295
83.0	23,436	$1,298,255	$13,089,576
84.0	24,899	$1,379,315	$13,906,857
85.0	26,363	$1,460,375	$14,724,139
86.0	27,826	$1,541,435	$15,541,420
87.0	29,289	$1,622,495	$16,358,701
88.0	30,753	$1,703,555	$17,175,982
89.0	32,216	$1,784,615	$17,993,264
90.0	33,679	$1,865,675	$18,810,545

Chart III-E-7



Probability-Weighted Damage Costs
vs System Upgrade Costs
EnergyNorth
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
2005 Dollars
67
69
71
73
75
77
79
81
83
85
87
89
EDD Level
25% Damage
50% Damage
75% Damage
High Upgrade Costs
Low Upgrade Costs

Chart III-E-8



Supply Shortfall Versus Annual EDD Level of Design
EnergyNorth
Supplementals
Storage
Pipeline
MMBtu
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
7,200
7,300
7,400
7,500
7,600
7,700
7,800
7,900
8,000
8,100
8,200
8,300
Annual EDD

Chart III-E-9

EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Pipeline Shortfall At EDD Level Above 7,079 Normal Annual EDD
By Month

	Annual EDD Level													
	7,077	7,100	7,200	7,300	7,400	7,500	7,600	7,700	7,800	7,900	8,000	8,100	8,200	8,300
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	2,745	15,696	28,357	40,341	52,180	63,896	75,163	86,174	97,185	108,196	119,207	129,989	140,221
Total	0	2,745	15,696	28,357	40,341	52,180	63,896	75,163	86,174	97,185	108,196	119,207	129,989	140,221

Storage Shortfall At EDD Level Above 7,079 Normal Annual EDD
By Month

	Annual EDD Level													
	7,077	7,100	7,200	7,300	7,400	7,500	7,600	7,700	7,800	7,900	8,000	8,100	8,200	8,300
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	35,911	108,441	179,254	249,827	319,477	388,415	455,501	519,663	583,343	645,956
Apr	0	0	30,687	114,890	163,132	171,303	179,568	188,008	196,447	204,886	213,325	221,765	230,204	238,643
May	0	0	0	144	423	703	983	1,269	1,812	2,355	2,898	3,441	4,129	5,202
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	18,834	77,102	81,888	87,037	92,232	97,427	102,622	107,817	113,011	118,206	123,401	128,596	133,791
Total	0	18,834	107,789	196,922	286,503	372,679	457,232	541,725	625,552	708,667	789,930	868,269	946,271	1,023,592

Supplementals Shortfall At EDD Level Above 7,079 Normal Annual EDD
By Month

	Annual EDD Level													
	7,077	7,100	7,200	7,300	7,400	7,500	7,600	7,700	7,800	7,900	8,000	8,100	8,200	8,300
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jan	0	0	0	0	0	13,375	35,735	58,601	82,391	106,528	131,727	159,248	187,010	215,461
Feb	0	411	28,579	56,861	85,371	104,056	115,503	126,951	138,399	150,210	162,557	174,903	187,250	199,596
Mar	0	5,762	7,833	9,904	11,976	14,047	16,118	18,190	20,261	22,332	24,660	27,589	30,842	34,639
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	6,172	36,412	66,765	97,347	131,478	167,356	203,742	241,050	279,071	318,944	361,740	405,103	449,697

Chart III-E-10

EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Assumptions:

Mean Annual EDD =	**7,079**	**EDD**
Std Dev Annual EDD =	**291.29**	**EDD**
Heating Increment =	**1,463**	**MMBtu/EDD**
No. of Firm Customers =	**80,303**	

EDD Level	Cumulative Probability Of Occurrence (p)	Probability Of Exceeding (1-p)	Frequency of Occurrence 1/(1-p) (years)	EDD Excess	Delta Supply (MMBtu) Pipeline	Storage	Supplementals	Total
7,100		0.4670	2.14	21.0	2,745	18,834	6,172	27,751
7,200		0.3297	3.03	121.0	15,696	107,789	36,412	159,897
7,300		0.2167	4.62	221.0	28,357	196,922	66,765	292,044
7,400		0.1320	7.58	321.0	40,341	286,503	97,347	424,190
7,500		0.0733	13.64	421.0	52,180	372,679	131,478	556,337
7,600		0.0377	26.55	521.0	63,896	457,232	167,356	688,483
7,700		0.0170	58.82	621.0	75,163	541,725	203,742	820,630
7,800		0.0050	200.00	721.0	86,174	625,552	241,050	952,777
7,900		0.0017	600.00	821.0	97,185	708,667	279,071	1,084,923
8,000		0.0010	1000.00	921.0	108,196	789,930	318,944	1,217,070
8,100		0.0000	100000.00	1,021.0	119,207	868,269	361,740	1,349,216
8,200		0.0000	100000.00	1,121.0	129,989	946,271	405,103	1,481,363
8,300		0.0000	100000.00	1,221.0	140,221	1,023,592	449,697	1,613,509
7,680		0.0211	47.32					
				(EDD Level MINUS Mean Peak)	**(EDD Excess TIMES Heating Increment) (MMBtu)**			

Chart III-E-11

EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

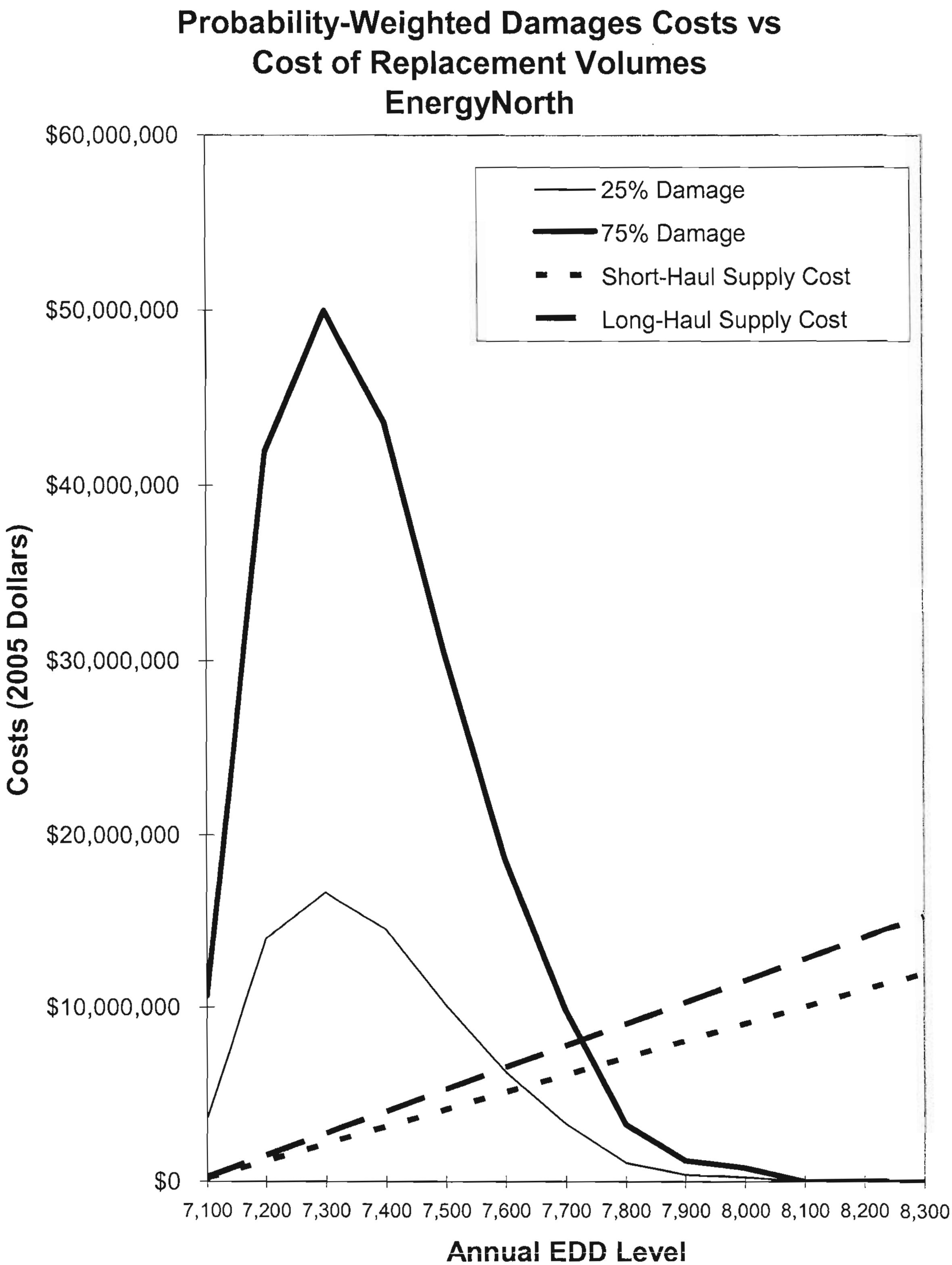
Assumptions:

Mean Annual EDD =	7,079.0	
Std Dev Annual EDD =	291.3	
Cost of Interruption/Day =	$27,039,948	
Supply Cost	$7.500	$/MMBtu
Long-Haul Capacity Cost	$583.58	$/MMBtu
Short-Haul Capacity Cost	$70.680	$/MMBtu
Storage D1 Cost	$13.800	$/MMBtu
Storage D2 Cost	$0.222	$/MMBtu

					Costs in 2005 Dollars				Costs in 2005 Dollars	
EDD Level	Cumulative Probability Of Occurrence (p)	Probability Of Exceeding (1-p)	Frequency of Occurrence 1/(1-p) (years)	Days Of Interruption	Cost of 25% Interruption	Prob Wghted Cost	Required Incremental Capacity (MMBtu)	Required Incremental Winter Volume (MMBtu)	Short-Haul Supply Cost	Long-Haul Supply Cost
7,100		0.4670	2.14	1	$7,619,357	$3,558,240	124	25,006	$203,615	$260,199
7,200		0.3297	3.03	6	$42,372,049	$13,968,652	719	144,201	$1,174,221	$1,500,825
7,300		0.2167	4.62	11	$76,929,747	$16,668,112	1,314	263,687	$2,147,194	$2,744,453
7,400		0.1320	7.58	16	$110,152,494	$14,540,129	1,911	383,849	$3,125,527	$3,994,098
7,500		0.0733	13.64	20	$138,479,257	$10,155,146	2,510	504,157	$4,105,105	$5,245,690
7,600		0.0377	26.55	25	$165,855,802	$6,247,235	3,110	624,588	$5,085,818	$6,499,462
7,700		0.0170	58.82	29	$193,409,949	$3,287,969	3,713	745,467	$6,070,185	$7,757,960
7,800		0.0050	200.00	32	$217,335,205	$1,086,676	4,318	866,602	$7,056,657	$9,019,209
7,900		0.0017	600.00	36	$240,357,380	$400,596	4,922	987,738	$8,043,129	$10,280,458
8,000		0.0010	1000.00	39	$261,000,226	$261,000	5,526	1,108,874	$9,029,582	$11,541,581
8,100		0.0000	100000.00	42	$281,139,916	$2,811	6,129	1,230,009	$10,015,876	$12,801,602
8,200		0.0000	100000.00	44	$300,089,449	$3,001	6,728	1,351,374	$11,003,680	$14,061,557
8,300		0.0000	100000.00	47	$318,033,986	$3,180	7,322	1,473,288	$11,995,331	$15,322,887
					Days Of Interruption times Cost of Interruption/Day	Cost of Interruption times Prob. of Exceeding			(Incremental Vol times Supply+D2 Costs) + (Incr Capacity times Short-Haul+ D1 Costs)	(Incremental Vol times Supply Cost) + (Incr Capacity times Long-Haul Cost)

EDD Level	Cost of 75% Interruption	Prob Wghted Cost
7,100	$22,858,072	$10,674,720
7,200	$127,116,148	$41,905,957
7,300	$230,789,240	$50,004,335
7,400	$330,457,481	$43,620,388
7,500	$415,437,772	$30,465,437
7,600	$497,567,406	$18,741,706
7,700	$580,229,848	$9,863,907
7,800	$652,005,616	$3,260,028
7,900	$721,072,140	$1,201,787
8,000	$783,000,677	$783,001
8,100	$843,419,748	$8,434
8,200	$900,268,346	$9,003
8,300	$954,101,957	$9,541

Chart III-E-12



IV. DESIGN OF THE RESOURCE PORTFOLIO

A. Portfolio Design

To generate the long-term resource plan, the Company evaluates the current resource portfolio in relation to the firm-sendout forecast developed in Section III above. Specifically, the Company evaluates the possible strategies for meeting demand with current resources and identifies the sensitivities and contingencies that need to be tested. Using the SENDOUT® model (described below), the Company is able to determine the least-cost portfolio that will meet the forecasted demand and test the sensitivity of the portfolio to key inputs and assumptions, as well as its ability to meet all of the Company's planning standards and contingencies. Based on the results of this analysis, the Company then makes preliminary decisions on the adequacy of the resource portfolio and its ability to meet system requirements in the longer term.

KeySpan has been using the New Energy Associates SENDOUT® model as its primary analytical tool in the portfolio design process in Massachusetts since 1996. Following the KeySpan merger, the SENDOUT® model was adopted for use in the EnergyNorth service territory. The SENDOUT® model is a linear programming optimization software tool used to assist in evaluating and selecting long-term portfolio strategies. SENDOUT® has several advantages over the ithink™-based dispatch model previously used by EnergyNorth. Foremost, SENDOUT® has the ability to examine the daily sendout requirements over an entire year simultaneously and select the optimum use of its portfolio of resources. This allows SENDOUT® to specify operating constraints such as the utilization of underground storage and supplemental supplies in design-forward planning instead of requiring such constraints to be input data.

The SENDOUT® model can be used in one of two ways. First, the model can be used to determine the best use of a given portfolio of supply, capacity and storage contracts to meet a specified demand. That is, it can solve for the dispatch of resources that minimizes the cost of serving the specified demand given the existing resource and system-operating constraints. The model dispatches resources based on the lowest variable cost to meet demand, assuming that demand charges are fixed. Second, the SENDOUT® model can be used to determine the optimal portfolio to meet a given demand. To do this, the model uses a linear programming algorithm to analyze the combination of contracts and the size of each contract (i.e., MDQ) to determine the combination that results in the lowest total cost, taking into account both variable and fixed costs.

B. Analytical Process and Assumptions

In preparing this IRP, the Company analyzed three demand scenarios: a low-demand case, a base case and a high-demand case, as described in Section III. In addition, the Company analyzed a cold-snap scenario and a contingency scenario using the Companies' current supply and capacity portfolio. The examination of these various scenarios enables the Company to test the adequacy and flexibility of the resource portfolio.

In this IRP, the Company has incorporated several key assumptions. First, the Company has assumed that, throughout the forecast period, there is no change in its current service obligation and that, as a result, it is responsible for planning for the capacity requirements for all firm customers.[1]. Second, the 2005/06 long-term, short-term and market-area portfolio was used as a proxy for the gas supply portfolio that will be used in all years of the forecast[2]. Although the actual contracts and contract terms will differ in every year, the Company believes that the current resource mix is representative of the actual supplies that the Company will use over the forecast period. Therefore, gas commodity costs were estimated using NYMEX futures prices for natural gas. All other costs represent actual contract costs including transportation and storage, fixed charges, variable charges, and other related costs. Fixed costs were not escalated over the forecast period because escalating all fixed costs at the same rate would maintain the relative ranking of the resources and would not, therefore, alter the decisions that the Company would make with respect to resource dispatch. Also, there is no indication that annual pipeline and underground-storage rate increases are a reasonable assumption.

C. Expected Available Resources

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[1] As noted in section III B above, this obligation excludes those firm transportation customers that are exempt from the Commission's mandatory capacity assignment rule. i.e. customers who had migrated to transportation service prior to the implementation of the mandatory capacity assignment rule or new customers who go direct to delivery only service.

[2] The Company did incorporate into the 2005/06 portfolio the upcoming addition of the short-haul capacity from Dawn to Waddington and the associated supply.

This section describes EnergyNorth's current resource portfolio and discusses the modifications that the Company anticipates making to the portfolio during the forecast period to meet sendout requirements. As discussed below, to meet design day and design year sendout requirements, the Company's resource portfolio is composed of the following categories of available resources: (1) long-haul and short-haul transportation; (2) underground storage services; (3) gas supply contracts; (4) supplemental resources; and (5) market area supply purchases. Chart IV-C-1 is a schematic of the Company's transportation and underground storage contracts effective November 1, 2006. Chart IV-C-2 is a table listing and description of the Company's resource portfolio.

1. Long-haul and Short-haul Transportation

EnergyNorth has capacity entitlements on multiple upstream pipelines that provide access to various production areas that afford the Company a level of operational flexibility to ensure the least-cost and reliable delivery of gas supplies.

The Company's pipeline capacity contracts fall into three primary categories. First, the Company has contract entitlements to long-haul capacity from the lower 48 states that is used to transport gas from production areas located in the Gulf of Mexico to the Company's New Hampshire citygates. The long-haul transportation capacity from the Gulf of Mexico is also used to transport gas from the production areas to the Company's underground storage facilities in Pennsylvania and New York. By using long-haul capacity to fill storage, the

Company is able to use these resources at a higher load factor. Second, the Company has contract entitlements to short-haul capacity that is used to transport gas from the underground storage fields in Pennsylvania and New York to the Company's citygates. These short-haul capacity entitlements are also used to transport non-storage supplies from the storage market area to the Company's citygates when the capacity is not being used to transport underground storage supplies. Third, the Company has a short-haul contract with entitlements to transport gas from the Dracut, Massachusetts interconnect on Tennessee Gas Pipeline to the Company's citygates. Lastly, effective November 1, 2006, the Company's capacity on Union Gas Limited ("Union") and TransCanada Pipelines Limited ("TransCanada") will become effective[3]. This new capacity path has entitlements from Dawn, Ontario to Kirkland/Parkway on Union and from Parkway to Waddington on TransCanada. The gas will then be transported to EnergyNorth's citygates using existing Iroquois and Tennessee capacity. The Company's long-haul and short-haul transportation contracts are described in more detail below:

- Iroquois Gas Transmission System

  EnergyNorth has contract entitlements to 4,047 MMBtus/day of firm transportation service on the Iroquois Gas Transmission System ("Iroquois") on a 365-day basis. Firm Canadian supplies are transported from the Canadian/New York border from Waddington, New York via the

[3] Union and TransCanada have each received the necessary regulatory authorizations. Both pipeline expansions are under construction and expected to be completed on schedule.

Iroquois system to the Tennessee Gas Pipeline ("Tennessee") interconnect at Wright, New York.

- Portland Natural Gas Transmission System

EnergyNorth has contract entitlements to 1,000 MMBtus/day of firm transportation service on the Portland Natural Gas Transmission System ("PNGTS") on a 365-day basis. PNGTS transports gas from Pittsburg, New Hampshire to the Company's city gate in Berlin, New Hampshire.

- Tennessee Gas Pipeline

In the production area, the Tennessee Gas Pipeline system splits into three legs: the 100 leg, the 800 leg, and the 500 leg. In addition, the Tennessee system is divided into six market zones, from Zone 0 and Zone 1 in Texas and Louisiana to Zone 6 in New England. See Chart IV-C-3 for a map showing the Tennessee Zone locations. EnergyNorth has capacity entitlements of 76,833 MMBtus/day on the Tennessee to its New Hampshire citygates. The Company's contract entitlements consist of transport volumes from Zone 0 and Zone 1 of up to 21,596 MMBtus/day to the Company's citygates in New Hampshire located in Zone 6 and to the Company's storage fields located in Zone 4 and Zone 5; from the Zone 4 and Zone 5 storage market area the Company's contract entitlement consists of transport volumes of up to 28,115 MMBtus/day to the Company's citygates; from the interconnect at Niagara in Zone 5 the Company's contract entitlements transport volumes of up to 3,122

MMBtus/day to the Company's citygates; from the interconnect at Wright, New York with Iroquois in Zone 5 the Company's contract entitlements transport volumes of up to 4,000 MMBtus/day to the Company's citygates; and finally, the Company has contract entitlements of up to 20,000 MMBtus/day from Dracut, Massachusetts located in Zone 6 to the Company's citygates.

- TransCanada Pipelines Limited

Effective November 1, 2006 EnergyNorth will have contract entitlements to 4,047 MMBtu/day of firm transportation service on TransCanada on a 365-day basis. Firm Canadian supplies are transported from the receipt point Parkway-Union, Ontario, to the interconnection between TransCanada and Union, to the interconnection with Iroquois at Waddington.

- Union Gas Limited

Effective November 1, 2006 EnergyNorth will have contract entitlements to 4,092 MMBtu/day of firm transportation service on Union on a 365-day basis. Firm Canadian supplies are transported from the receipt point at Dawn, Ontario to the interconnection with TransCanada at Parkway.

2. Underground Storage Services

EnergyNorth's underground storage contracts provide the Company with the ability to meet winter-season loads, while avoiding the expense of adding 365-day long-haul transportation capacity. These contracts enable EnergyNorth to store approximately 2.5 million MMBtus of gas. These underground storage supplies allow EnergyNorth to serve a percentage of the winter period requirements with gas injected during the off- peak period and to manage short-term fluctuations in demand during the winter period. It is the Company's practice to have storage inventories approximately 95% full as of November 1st of each year, thus leaving approximately 5% of the storage capacity available for balancing purposes.

The Company contracts with the following storage providers;

- Dominion Transmission, Incorporated

  Under rate schedule GSS which provides 102,700 MMBtus of storage capacity with a withdrawal rate of 934 MMBtus/day and an injection rate of 934 MMBtus/day.

- Honeoye Storage Corporation

  Under rate schedule SS-NY that provides 245,280 MMBtus of storage capacity with a withdrawal rate of 1,957 MMBtus/day and an injection rate of 1,362 MMBtus/day.

- National Fuel Supply Corporation

  Under rate schedule FSS that provides 670,800 MMBtus of storage capacity with a withdrawal rate of 6,098 MMBtus/day and an injection rate of 4,472 MMBtus/day. Along with this storage service, the Company also contracts for 365-day firm transportation under rate schedule FST in order to transport the storage gas into and out of the storage field.

- Tennessee Gas Pipeline

  Under rate schedule FS-MA that provides 1,560,391 MMBtus of Storage capacity with a withdrawal rate of 21,844 MMBtus/day and an injection rate of 10,404 MMBtus/day.

3. Gas Commodity

Prior to March 2006, EnergyNorth was a party to a contract with Merrill Lynch Commodities, Inc. ("MLCI") whereby MLCI both managed the resource portfolio and provided citygate gas supplies to EnergyNorth's firm sales customers. Under this arrangement, MLCI was obligated to deliver up to 77,833 MMBtus/day of citygate supplies. Effective April1, 2006, the Company terminated its agreement with MLCI and is now responsible for contracting for the necessary gas supply to meet firm sendout requirements. In order to meet customer requirements the Company will contract for a mix of seasonal, monthly and daily supplies from a diverse group of suppliers that are designed to take advantage of the interstate pipeline capacity paths held by the Company.

(a) Domestic Gas Supply

As described above, the Company's resource portfolio is currently structured to have a high level of flexibility to adapt to changing market conditions and regulatory obligations as they relate to Supplier Service. This is especially true with respect to the Company's domestic gas commodity commitments. Generally speaking, EnergyNorth enters into agreements that allow it the flexibility to eliminate up to 100 percent of its existing domestic gas commodity purchases in less than a twelve-month period. As of the date of this filing, the Company is in the process of issuing Request For Proposals ("RFPs") for seasonal supplies sourced from domestic gas supply markets to meet customer requirements for the upcoming winter season. These seasonal volumes will later be supplemented as necessary with index-based first of the month and/or daily market purchases.

(b) Market Area Supply

Market area purchases are short-term arrangements that the Company makes in order to achieve a higher utilization of existing portfolio resources and prolong the effective utilization of the Company's short-haul capacity. On a daily basis during the peak period, the Company has the opportunity to take advantage of market-area resource opportunities to bring gas supplies to the Company's citygates or to inject them into the Company's underground storage fields. In the past, gas injected into storage during the off-peak season was generally lower priced than gas purchased in the peak season. However, experience indicates that market prices during the winter period can drop below storage inventory costs. Furthermore, prices in the later part of the winter season can be higher or lower than prices in the early part of the winter season, depending on market conditions. Market-area purchases generally refer to purchase in either Tennessee Zone 4 at or near the storage region or Zone 6 at Dracut, MA, or at the Company's citygates. These purchases minimize the cost of the resource portfolio because: (1) the Company is avoiding demand charges for capacity that is not needed on a design-day or design-season basis; and (2) the Company is able to better utilize existing transportation capacity that is available when underground storage supplies are not being transported to the Company's citygates.

(c) Canadian Gas Supply

In addition to domestic gas supplies, the Company currently holds several long-term supply contracts with Canadian suppliers. One of the Canadian gas supply contracts consists of a bundled capacity and gas commodity from western Canada pursuant a contract with Alberta Northeast, Ltd. ("ANE"), which is set to expire on November 1, 2006. This contract has been replaced with two separate agreements for the purchase of gas at Dawn, Ontario. Supply contracts have been executed with DTE Energy for up to 1,986 MMBtu/day and Sempra for up to 2,106 MMBtu/day both commencing on November 1, 2006. The supply will be transported on Union from Dawn to the interconnect with TransCanada at

Parkway, and then transported by TransCanada from Parkway to the Iroquois interconnect at Waddington.

The Company also holds contracts with BP Canada Energy Company for 1,599 MMBtu/day and with Nexen Marketing for 1,600 MMBtu/day. Both of these contracts deliver into Tennessee at Wright, NY.

Lastly, for the 2006/07 peak season, the Company is pursuing a replacement contract for its CoEnergy Trading Company ("CoEnergy") supply contract that expired on February 28, 2006.

These Canadian gas supplies represent an important component in maintaining the diversity, flexibility and reliability of the resource portfolio. Specifically, the Company's new supply and capacity resources effective November 1, 2006 that replaced the Company's expiring bundled ANE arrangement allow the Company to access a new and liquid supply point at Dawn.

4. Supplemental Resources

In addition to interstate pipeline and storage resources, EnergyNorth utilizes supplemental peaking supplies to meet its design day and design season requirements in excess of pipeline resources. Peaking supplies are an important component of the resource mix because these supplies provide the Company with the ability to respond to fluctuations in weather, economics and other factors driving the Company's sendout requirements. The Company utilizes both off-system and on-system supplemental resources.

Off system supplemental resources include the Company's contract with Granite Ridge, L.L.C. ("Granite Ridge," formerly "AES Londonderry") as well as the Company's firm vapor service ("FVS") contract with Distrigas of Massachusetts ("DOMAC"). The Company is currently pursuing a replacement contract for its DOMAC FVS-256 contract that expires on October 31, 2006.

On-system supplemental resources are the local production plants that store LNG and liquid propane until vaporized. It is the Company's practice to have its supplemental storage facilities full as of November 1st of each year.[4] EnergyNorth's on-system supplemental facilities are distributed strategically across the service territory, which enhances service reliability and provides a source of supply for the entire distribution system. Chart IV-C-4 shows the locations of these facilities. Because these resources can be brought on line quickly, these plants can be used to meet hourly fluctuations in demand, maintain deliveries to customers and balance pressures across portions of the distribution system during periods of high demand. Most importantly, these resources are vital in preserving delivery pressures in the event that an off-system resource becomes unavailable. The Company's forecasted need for on-system supplemental supplies over the maximum pipeline availability is 305,000 MMBtu for the 2006/07 peak season (see Chart IV-D-1). These supplemental volumes are the supplies that must be available to the Company's distribution system to ensure service to customers when the Company has exhausted its available pipeline supplies. Thus, the availability of liquid natural gas and propane gas to

[4] The on-system LNG storage capacity is not sufficient to meet the full seasonal requirements without refill throughout the winter season.

refill the Company's local storage tanks throughout the winter season is an ever-increasing necessity. The Company's DOMAC contracts (FLS-160 and FLS-162) are currently the primary sources of LNG refill throughout the winter season. The Company is currently pursuing a replacement contract for its DOMAC FLS-162 contract that expires on October 31, 2006. In addition, as it has for the last several years, the Company has contracted for a dedicated trucking arrangement in order to guarantee the availability of both trailers and drivers to truck the LNG from the source point to the Company's facilities during the upcoming winter season. Lastly, the Company contracts seasonally for propane supplies with Eastern Propane Company. When contracting for propane supplies, the Company also firms up the necessary trucking arrangements for delivery of these supplies. ,

5. Pending Contract Negotiations

At the time of this filing, the Company is currently in the process of finalizing its portfolio for the 2006/07 winter season. The Company is seeking to renew and/or replace the following resources which expire before November 1, 2006:

Contract	MDQ	Annual Quantity (MMBtu)	Description
DTE Energy Trading	20,000	1,800,000	Seasonal winter supply received at TGP/Dracut meter station.
Distrigas of Massachusetts Corporation FVS256	8,000	1,208,000	Firm vapor service with varying monthly take quantities.
Distrigas of Massachusetts Corporation FLS162	6,300	50,000	Firm liquid service available during winter season for LNG refill

In addition, as discussed above, now that the Company is managing its portfolio in-house, the Company will need to contract directly for its own domestic winter supply resources.

6. Replacement and Incremental Resources

Changes in EnergyNorth's resource needs are caused by changes in its firm demand, (i.e., load growth, load loss and changes in load shape). The Company differentiates incremental and replacement resource needs primarily in terms of how a need arises. The need to increase (or decrease) resources arises when the capacity of the Company's resource portfolio is not substantially equivalent to its firm demand requirements. A replacement resource need occurs when the term of an existing resource comes up for expiration and the Company's firm demand requirements are substantially the same (i.e., the resource is not avoidable). The Company applies the same decision-making process to meet replacement needs as it applies to incremental needs.

A critical component of identifying a resource need is defining the load shape of the demand that needs to be met. "Shape" refers to the degree of uniformity that a resource need exhibits throughout the course of a year. In characterizing the shape of resource needs, three general terms are applied herein: "baseload," "seasonal," and "peaking". A need that is substantially uniform throughout the year is described as a "baseload" need; a need that is driven by temperature fluctuations, and is therefore concentrated in a finite portion of the year (i.e. 60-180 days), is described as a "seasonal" need; a need that is observed at the very upper limits of the demand profile (i.e., the coldest days of the year) is described as a "peaking" need. The Company notes specific resource needs do not necessarily fall discretely into one of these categories, but rather can exhibit characteristics of any or all of these classifications.

Determining the shape of a need is also important in terms of narrowing the range of possible resource options that may be able to satisfy the need. Baseload needs for example, tend to be best met through pipeline supply options. On the other hand, 365-day pipeline resources tend to be less efficient in meeting seasonal needs because the fixed capacity charges become concentrated across a relatively short demand period, which drives the unit cost up. Conversely, resources that can be inventoried and dispatched in response to temperature variations (such as underground storage and LNG) tend be cost-effective in meeting seasonal demands. Finally, peaking demands are likely to be best met by on-system LNG or propane facilities because of the flexibility with which these resources can be dispatched.

When a resource need arises, the Company attempts to identify all of the possible resource options that may be able to meet that need. The Company regularly requests, receives and reviews promotional material regarding new or revised services from various supply-related entities. In addition, the Company endeavors to maintain continuous contact with suppliers, pipelines operators and other service providers. Through these efforts, the Company has compiled and continually updates a library of service providers and resource alternatives.

Using this information, the Company is able to develop a list of potential service providers to whom Requests for Proposals ("RFPs") will be sent. The RFP process effectively generates tailored service bids from potential service provides at market prices. The responses to an RFP establish the set or "universe," of potential resource options available to meet a particular need at a given point in time. The Company then performs a preliminary review to narrow the set down to an appropriate range for further analysis. This preliminary screening is dictated in part by the nature of the demand (i.e., the size and shape of the need) and by the planning time horizon. The time horizon is also an important element because the availability of specific resource alternatives may not perfectly coincide with the initial timing of an identified need. For example, an incremental seasonal need arising four years into the future may be met best by a storage option that will become available in three years if no other storage alternatives are available until the fifth year.

During the forecast period, EnergyNorth is faced with key decisions regarding the expiration and renewal of a number of contracts in its resource portfolio. Existing resources from the Company's 2006/07 portfolio that are set to expire during the five-year forecast period include:

Contract	MDCQ	Annual Quantity (MMBtu)	Date of Expiration
Granite Ridge Energy, LLC	15,000	450,000	9/30/07
BP Canada Energy Company	1,599	583,635	4/01/07
Distrigas of Massachusetts Corporation FLS160		100,000	10/31/10
Dominion Transmission 300076	934	102,700	3/31/2011
DTE Energy Trading	1,986	724,890	10/31/2007
Honeoye Storage Corporation	1,957	245,280	04/01/08 Evergreen
Iroquois Gas Transmission 47001	4,047	1,477,155	10/31/2011
National Fuel Company N02358	6,098	2,225,770	3/31/08 Evergreen
National Fuel Company O02357	6,098	670,800	3/31/08 Evergreen
NEXEN Marketing	1,600	584,000	4/01/07
Sempra Energy Trading	2,106	768,690	10/31/2007
Tennessee Gas 523	21,844	1,560,391	10/31/2010
Tennessee Gas 632	15,265	5,571,725	10/31/2010
Tennessee Gas 2302	3,122	1,139,530	10/31/2010
Tennessee Gas 8587	25,407	9,273,555	10/31/2010
Tennessee Gas	9,039	3,299,235	10/31/2010

Contract	MDCQ	Annual Quantity (MMBtu)	Date of Expiration
11234			
Tennessee Gas 33371	4,000	1,460,000	10/31/2011
Tennessee Gas 42076	20,000	7,300,000	10/31/2010
Union Gas M1200	4,092	1,493,580	10/31/2007

Following the Company's planning process described above, during the forecast period, the Company will employ a three-step analysis to reach its conclusions on contract renewals. First, the Company will evaluate the need to maintain the contracts as part of the resource portfolio. As part of this need analysis, the Company will consider the trends in transportation migration and the growth in transportation relating to new customers that have not previously been served by the Company, and therefore, are not subject to the assignment of capacity. If the Company determines that the resource is needed to meet firm sendout requirements, the Company will consult with competitive suppliers serving customers on EnergyNorth's system to solicit their input on the Company's contract renewals. Second, depending on the type of need, the Company will canvas the marketplace to determine the availability of a replacement resource. And, where appropriate, the Company will solicit competitive bids to determine the lowest-cost available resource. Finally, the Company will evaluate non-price factors associated with the available replacement options such as flexibility, diversity, reliability and contract term to determine the least-cost, most reliable option to meet the Company's resource need.

This same approach will be implemented when the need for a new resource to be added to the portfolio arises. As discussed in Section IV.D below, the Company is forecasting a need for incremental capacity or citygate-delivered supplies to meet customer requirements during the forecast period. The Company has already initiated discussion with Tennessee regarding incremental capacity additions. Currently, incremental capacity is not available on Tennessee's Concord lateral, the lateral which provides service to the Company's distribution system. Preliminary discussion with Tennessee has yielded estimates in the \$12M – \$16.5M range for the needed upgrades to the lateral in order to provide incremental volumes to the Company's citygates.

D. Adequacy of the Resource Portfolio

Although the base case scenario is intended to represent the most probable demand case, customer demand could vary within the range of the low-demand and high-demand case. Accordingly, the resource plan must possess a level of flexibility to adjust to changing economic conditions, while ensuring that adequate resources are available to meet customer requirements on the peak day. As described below, the EnergyNorth resource portfolio currently possesses the flexibility to meet design-year requirements on a reliable basis.

To ensure the delivery of needed supplies on the peak day, however, the Company anticipates that it will need to obtain additional firm capacity or citygate-delivered supply during the forecast period.

1. Base Case

The Company's resource plan shows that it can meet base case design year load requirements throughout the forecast period. However, to do so, the Company will need to supplement its resource portfolio with additional firm capacity or citygate-delivered supply beginning in the year 2008/09. The daily contracted quantities required to adequately meet the anticipated sendout requirements are set forth in Chart IV-D-3 and are summarized as follows:

Other Purchased Resources
Base Case

YEAR	Design Day Capacity (MMBtu/day)	Design Heating Season Volume (MMBtus)
2006/07	0	0
2007/08	0	0
2008/09	0	53,300
2009/10	5,310	48,000
2010/11	19,660	128,000

The projected incremental requirement for the design day begins in 2009/10 as relatively small in relation to the Company's total peak-day requirement (i.e., approximately three percent in 2009/10 rising to thirteen percent in 2010/11), but grows over time. The Company plans to monitor the factors that drive the need for incremental capacity and to begin plans for addressing these needs.

These factors include: (a) realization of the load growth that is forecasted by the Company's demand model; (b) migration of new load directly to Supplier Service over the next two years; (c) customer participation in DSM programs over the forecast period; and (d) other social and political factors that influence the demand for natural gas, such as energy legislation and environmental considerations. If events warrant, the Company will prepare an analysis of need and available alternatives and procure the necessary capacity to serve the needs of customers.

2. High-Demand Case

The Company's resource plan shows that it can meet high-demand case design year load requirements throughout the forecast period. In this scenario, as in the base case, the Company will need to supplement its resource portfolio with additional firm capacity or citygate-delivered supply beginning in 2007/08. These additional purchases are set forth in Chart IV-D-18 and are summarized as follows:

Other Purchased Resources
High Case

YEAR	Design Day Capacity (MMBtu/day)	Design Heating Season Volume (MMBtus)
2006/07	0	0
2007/08	730	145,000
2008/09	22,140	311,600
2009/10	40,000	245,700
2010/11	40,000	376,400

In the high-demand case, the amount of Other Purchased Resources needed to meet design day incremental capacity requirements is greater than that relied upon in the base case (i.e., less than one percent in 2007/08 rising to twenty-five percent in 2010/11). Should incremental demand increase consistent with the high-demand case projections, the Company would acquire adequate, least-cost capacity resources to address this need.

3. Low-Demand Case

As shown in Chart IV-D-33, the Company's resource portfolio is adequate to meet total low-demand case system requirements in the forecast period.

Under any of these three scenarios, the Company believes that sufficient capacity and supplies will be available in the market to meet its customers' needs. The Company will follow its resource planning process to evaluate and fill identified needs with a least-cost, reliable mix of contracted capacity and/or citygate delivered gas supplies. This approach provides a high level of flexibility to meet uncertainties in future demand, while ensuring the adequacy of the overall resource portfolio.

E. Cold Snap Analysis

In addition to the design day, design year and normal year planning standards, the Company also evaluates the capability of the resource portfolio to meet sendout requirements during a protracted period of very cold weather, which is referred to as a "cold snap."

To generate its cold-snap scenario, the Company selected the actual seven-day period of coldest weather experienced by the Company leading to the highest supplementals requirement. This seven-day period, from the Company's twenty-three year historical effective degree day (EDD) database for Manchester, NH, was January 9, 2004 through January 15, 2004.[5]

The Company then analyzed the effectiveness of the portfolio with an EDD pattern of (a) normal EDD through January 2nd (b) the cold-snap EDD on January 3rd through January 9th followed by (c) normal EDD. In doing this, the Company substituted the coldest seven-day period in its normal weather scenario with the cold-snap scenario.

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[5] This seven-day period with 447 EDD is not the coldest seven-day period in the database. The coldest seven-day period was a 450 EDD total that occurred between January 16 and January 22, 2000.

Using base case demand, the Company analyzed the effectiveness of the portfolio in meeting the requirements of the cold-snap scenario. The results of the simulation, using the SENDOUT® model, showed that the Company's portfolio can meet the cold-snap requirement adequately (see Chart IV-E-1).

F. Contingency Planning

As part of the settlement agreement dated August 19, 2005, the Company agreed to include in this IRP, a contingency plan that would address the following supply/capacity interruptions:

(1) Displacement of gas from the Company's Massachusetts affiliates to New Hampshire to the extent feasible under the combined OBA on the Tennessee Gas Pipeline Company system;

(2) The potential for and related cost if the Company were to increase the level of dedicated trucking to deliver liquid supplies to New Hampshire during periods when vaporized LNG from its Massachusetts affiliates' facilities cannot be displaced via pipeline from Massachusetts to New Hampshire;

(3) A reasonable range of potential supply or capacity disruptions under design day weather conditions and the Company's response

to each specified situation, including a loss of pipeline and LNG or propane supplies;

Each of these scenarios is discussed in detail below.

1. Displacement of gas from the Company's Massachusetts affiliates to New Hampshire to the extent feasible under the combined OBA on the Tennessee Gas Pipeline Company system;

When both EnergyNorth and the Company's Massachusetts affiliates were parties to their respective Asset Management Agreements with Merrill Lynch, from time to time, when capacity was available, the Company would temporarily displace gas across the territories to the extent possible using the Company's Operational Balancing Agreement ("OBA") with Tennessee Gas Pipeline ("Tennessee"). This activity was possible because both parties had similar pricing structures in the agreements with Merrill whereby imbalances from volumes transferred between the territories would be paid back in-kind within days and certainly before month-end. Now that EnergyNorth is no longer a party to such an agreement with Merrill, the Company no longer intentionally displace volumes between the territories. Thus, since this activity no longer transpires, the Company does not develop a contingency plan for it.

2. The potential for and related cost if the Company were to increase the level of dedicated trucking to deliver liquid supplies to New Hampshire during periods when vaporized LNG from its Massachusetts affiliates' facilities cannot be displaced via pipeline from Massachusetts to New Hampshire;

From time to time, the Company seeks to displace liquid supplies delivered via truck to New Hampshire with vaporized LNG from certain of its Massachusetts tanks. The vaporized LNG is "delivered" to New Hampshire via the Company's OBA with Tennessee, whereby EnergyNorth increases its volume taken from the pipeline and the Massachusetts companies correspondingly decrease their volumes taken from the pipeline by the same amount. By implementing this strategy, the Company reduces the number of trucks dispatched to New Hampshire and minimizes the associated logistics of trucking deliveries. This activity is performed to the extent the resources are available. However, the Company does not rely on this activity to meet either its design day or design season needs. Therefore the Company did not develop a contingency plan for the absence of it.

3. Potential Supply or Capacity Disruptions

3a. Disruption at DOMAC

Throughout the forecast period, EnergyNorth relies on peaking supplies from DOMAC, now known as Tractebel LNG North America, to meet both the design year and design day needs of customers. Therefore, the loss of these resources would cause a supply deficit during the forecast period. KeySpan has had experience in dealing with the disruption of its DOMAC supplies. In light of a ban imposed by the U.S. Coast Guard on LNG vessels in entering Boston Harbor following the events of September 11, 2001, KeySpan was forced to implement a contingency plan to address this supply disruption.

In this filing, EnergyNorth addresses a contingency plan to meet a supply deficit similar to that created by the loss of DOMAC LNG supplies in 2001. For this analysis, EnergyNorth considers three scenarios: (1) no LNG shipments for the month of October, (2) no LNG shipments or sporadic shipments for the winter period; and (3) no shipments for the long term. For the first scenario the Company determined that there would not be a material effect on EnergyNorth, since the Company's tanks are full in early fall. In addressing the other scenarios, EnergyNorth would first need to distinguish between its liquid and vapor needs for the season. To determine liquid needs, the Company would consider its immediate need to fill the tanks to their maximum capacity, as well as the short-term, minimum liquid needs for a design winter.

The vapor supplies that the Company would need to replace for the design winter would also need to be determined. In general, incremental pipeline deliveries can be substituted for these volumes, assuming that the pipelines are able to make such deliveries. The Company would engage in discussions with various service providers to meet this need in a number of ways. For example, there may be an opportunity to increase deliveries from the Iroquois pipeline into

TGP, or to effect modifications to underground storage contracts to provide excess deliverability out of storage, as well as an opportunity to secure additional deliveries on the Tennessee pipeline.

With respect to the immediate and short-term liquid needs, the Company would immediately implement its contingency plan. This plan would call for liquid deliveries from various LNG facilities including, but not limited to; the NSTAR Gas facility in Hopkinton, Massachusetts, the Philadelphia Gas Works facility in Philadelphia, Pennsylvania, the Transco facility in Carlstadt, New Jersey, and/or the Gaz Metropolitain facility in Montreal, Canada. In addition to LNG deliveries, the Company would also call for incremental propane deliveries from its regional propane supplier as well as other suppliers in the northeast corridor.

In the event of a long-term supply disruption, the Company would need to replace all of its existing DOMAC LNG contracts with another source of supply and related transportation. Should this become a reality, the Company would act immediately and initiate discussions with suppliers and Tennessee Gas Pipeline.

3b. Supply Disruption at Dracut

Throughout the forecast period, EnergyNorth relies on gas supplies being sourced from the Dracut, MA interconnect on Tennessee Gas Pipeline to the Company's citygates to meet both the design-year and design-day needs of customers. Therefore, the loss of these resources would cause a supply deficit during the forecast period. The timing of the disruption as well as the extent of the disruption would determine the actions taken by the Company to fill the void.

A disruption to this pipeline delivered supply could be replaced with a mix of various gas supplies available to the Company. These supplies include but are not limited to:

- Citygate delivered spot-market purchases;
- Incremental long-haul supplies delivered from the Gulf using the Company's long-haul capacity;
- Underground storage volumes delivered from the storage fields using the Company's short-haul storage capacity;
- TGP Zone 4 market area supplies transported on the Company's short-haul capacity from zone 4 to zone 6;
- The Company's existing DOMAC FVS contract; and
- On-system resources of both LNG and propane

Lastly, should the Company exhaust all of the above mentioned options, the Company would then look to its Massachusetts and New York affiliates for assistance in supplying the needed volumes in order to maintain system integrity.

<u>3c. Supply and Capacity Disruptions in the Gulf of Mexico</u>

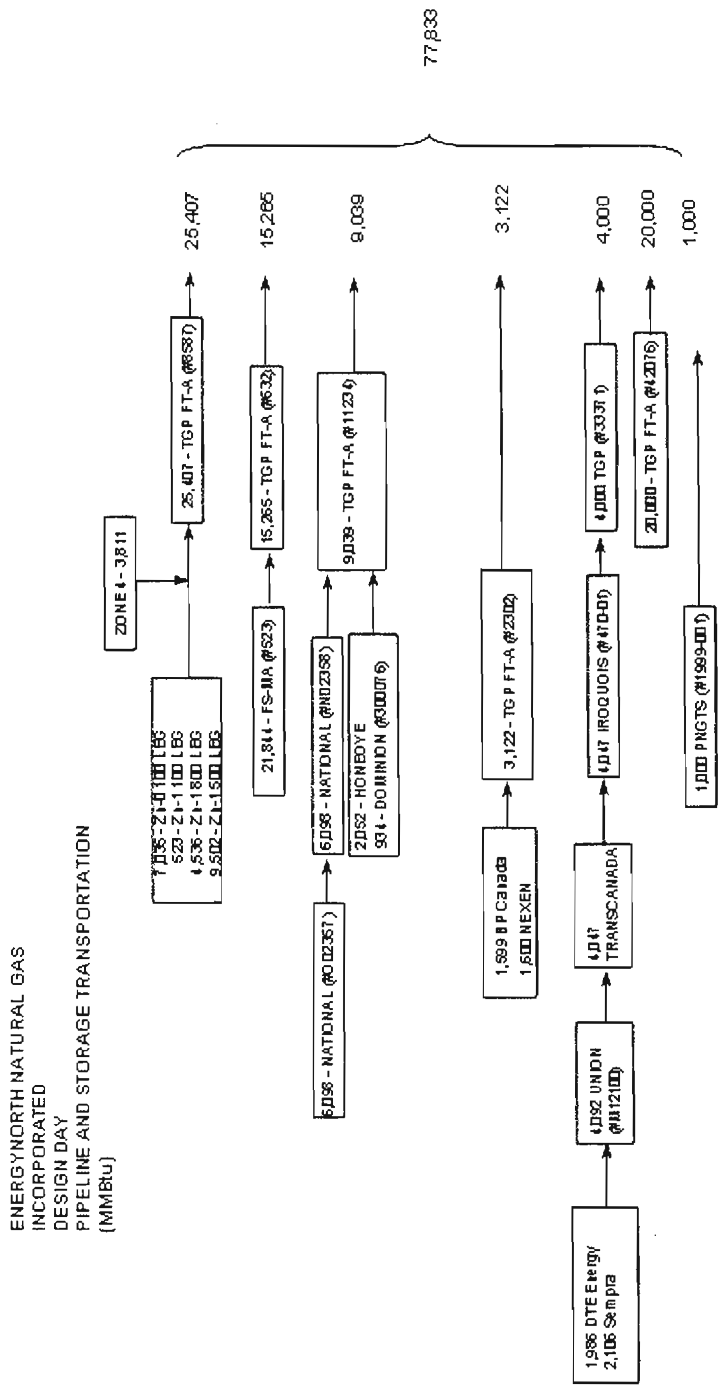
Throughout the forecast period, EnergyNorth relies on gas supplies being sourced from the Gulf of Mexico on Tennessee Gas Pipeline to the Company's citygates to meet both the design-year and design-day needs of customers. Therefore, the loss of these resources would cause a supply deficit during the forecast period. In the aftermath of Hurricanes Katrina and Rita in 2005, KeySpan took several steps in order to ensure supply reliability for the 2005/2006 winter season for its New Hampshire and Massachusetts customers. Should a similar event again occur the Company would follow the same process it implemented following Hurricanes Katrina and Rita ("2005 Hurricanes"). First the Company would determined its overall supply capabilities on a peak day and peak season basis, from "at risk" locations, *i.e.,* Tennessee's 500-leg and Texas Eastern's ELA and WLA regions during the 2005 Hurricanes. Next the Company would fill both its underground and LNG storage facilities going into the winter and implement a conservative storage withdrawal strategy in order to guarantee maximum storage withdrawals as far into the winter as possible. Finally, the Company would firm-up winter supplies traditionally sourced in the Gulf Coast at points upstream of the constrained points. Specifically, in the fall of 2005, KeySpan secured 131,000 MMBtu/day, from sources located downstream of the affected areas as well as an additional 20,000 MMBtu/day directly from DOMAC (9,502 MMBtu/day was secured on behalf of EnergyNorth). These volumes equated to 98 percent of the "at risk" New England volume.

It is also important to note that the Company is an active member of the Northeast Gas Association's ("NGA") Gas Supply Task Force.[6] The Task Force meets periodically throughout the winter season, and more often if the situation warrants. As a member of this Task Force, the Company can request to convene a meeting in order address either a regional or a Company-specific issue and seek the assistance of fellow members if needed.

3d. Emergency Curtailment Plan

In the event that despite all reasonable efforts, a force majuere event prevents the Company from securing adequate supply to maintain deliverability to customers, the Company would implement its emergency curtailment plan. A copy of that plan was filed with the Commission on November 1, 2005.

[6] This Task Force was originally established by the New England Gas Association (now NGA) Board of Directors and chartered to coordinate the activities of New England (now Northeast) gas industry participants with regard to issues related to regional gas supply and deliverability.


ENERGYNORTH NATURAL GAS
INCORPORATED
DESIGN DAY
PIPELINE AND STORAGE TRANSPORTATION
(MMBtu)
7,035 - Z1-0 100 LEG
523 - Z1-1 100 LEG
4,536 - Z1-1 800 LEG
9,502 - Z1-1 500 LEG
ZONE 4 - 3,811
25,407 - TGP FT-A (#8587)
21,844 - FS-MA (#523)
15,265 - TGP FT-A (#632)
6,098 - NATIONAL (#O02357)
6,098 - NATIONAL (#N02358)
2,052 - HONEOYE
934 - DOMINION (#300076)
9,039 - TGP FT-A (#11234)
1,599 BP Canada
1,600 NEXEN
3,122 - TGP FT-A (#2302)
1,986 DTE Energy
2,106 Sempra
4,092 UNION
(#M12100)
4,047
TRANSCANADA
4,047 IROQUOIS (#470-01)
4,000 TGP (#33371)
20,000 - TGP FT-A (#42076)
1,000 PNGTS (#1999-001)
25,407
15,265
9,039
3,122
4,000
20,000
1,000
77,833

EnergyNorth Natural Gas Incorporated
Resource Listing

Long-haul and Short-haul Transportation Contracts

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Notes
EnergyNorth Natural Gas Incorporated	Iroquois	47001	RTS-1	4,047	1,477,155	10/31/2011	Part-284 transportation service (365-day). This contract is used to transport volumes from Waddington, NY to the Iroquois interconnect with TGP at Wright, NY.
EnergyNorth Natural Gas Incorporated	National Fuel	N02358	FST	6,098	2,225,770	3/31/2008	Part-284 transportation service (365-day) associated with the FSS service 002357, used for storage injection and or withdrawal across National Fuel pipeline system and into and out of the FSS storage. The contract term and associated discounted rate were extended through March 31, 2004, and then year to year thereafter unless one-year written notice is provided by either party. Amendment dated March 21, 2002 gives National Fuel the option of notifying the company by February 28th to discontinue the discounted rate. The Company has been notified by National Fuel effective April 1, 2007 the discounted rate will no longer be in effect.
EnergyNorth Natural Gas Incorporated	Portland Natural Gas	1999-001	FT	1,000	365,000	10/31/2019	Part-284 transportation service (365-day). This contract is used to transport volumes from Pittsburg, New Hampshire to EnergyNorth citygate located in Berlin, New Hampshire.
EnergyNorth Natural Gas Incorporated	Tennessee	632	FT-A	15,265	5,571,725	10/31/2010	Part-284 transportation service (365-day). This contract is used to transport volumes from FS-MA storage (zone 4) to EnergyNorth city gates.
EnergyNorth Natural Gas Incorporated	Tennessee	2302	FT-A	3,122	1,139,530	10/31/2010	Part-284 transportation service (365-day). This contract is used to transport Canadian supply (BP Canada & NEXEN) from Niagara, New York (zone 5) to EnergyNorth city gates.
EnergyNorth Natural Gas Incorporated	Tennessee	8587	FT-A	25,407	9,273,555	10/31/2010	Part 284 transportation service (365-day). This contract is used to transport volumes from the access area (zones 0 and 1) and storage (zone 4) to EnergyNorth city gates (zone 6) with primary receipt points of 21,596 MMBtu/day from zones 0 and 1 and 3,811 MMBtu from zone 4. The contract term has been extended from October 31, 2003 to October 31, 2010.
EnergyNorth Natural Gas Incorporated	Tennessee	11234	FT-A	9,039	3,299,235	10/31/2010	Part 284 transportation service (365-day). This contract is used to transport volumes from three storage fields (Honeoye, National Fuel and Dominion) to EnergyNorth's city gates (zone 6).
EnergyNorth Natural Gas Incorporated	Tennessee	33371	NET-NE	4,000	1,460,000	10/31/2011	Part 284 transportation service (365-day) used to transport gas from Iroquois at Wright, NY to EnergyNorth city gates. Effective November 1, 2006 the contract will be converted from a NET-NE agreement to a service agreement under Rate Schedule FT-A.
EnergyNorth Natural Gas Incorporated	Tennessee	42076	FT-A	20,000	7,300,000	10/31/2010	Part 284 transportation service (365-day). This contract is used to transport volumes from Dracut, MA (zone 6) to the EnergyNorth city gates (zone 6).
EnergyNorth Natural Gas Incorporated	TransCanada		FT	4,047	1,477,155	10/31/2016	Canadian Transportation service (365-day). This contract is used to transport volumes from Parkway-Union to TransCanada interconnect with Iroquois.
EnergyNorth Natural Gas Incorporated	Union Gas	M12100	M12	4,092	1,493,580	10/31/2007	Canadian transportation service (365-day). This contract is used to transport volumes from Dawn to Union interconnect with TransCanada.

EnergyNorth Natural Gas Incorporated
Resource Listing

Underground Storage Services

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDWQ	Annual Quantity MSQ	Expiration Date	Notes
EnergyNorth Natural Gas Incorporated	Dominion	300076	GSS Storage	934	102,700	3/31/2011	Part-284 storage service that provides 102,700 MMBtu of storage capacity at a withdrawal rate of 934 MMBtu/day and an injection rate of 934 MMBtu/day. Injection ratchets if inventory is under 50% the calculation is 1/180 x 102,700 for injection rights. If the inventory is above 50% the calculation is 1/214 x 102,700. April to July Dominion allows for 115% of the daily injection rights The contract term has been extended from March 31, 2006 to March 31, 2011.
EnergyNorth Natural Gas Incorporated	Honeoye		SS-NY Storage	1,957	245,280	4/1/2008	Part-157 (7C) storage service that provides 145,280 MMBtu of storage capacity at a withdrawal rate of 1,957 MMBtu/day and an injection rate of 1,957 MMBtu/day. The company is currently exercising the evergreen provision provided in the contract and extending the contract on a year to year basis. If operational integrity should be in jeopardy Honeoye reserves the right to institute a storage ratchet calculation as follows MSQ/210 days.
EnergyNorth Natural Gas Incorporated	National Fuel	O02357	FSS Storage	6,098	670,800	3/31/2008	Part-284 storage service (150-day) that provides 670,800 MMBtu of storage capacity, with a withdrawal rate of 6,098 MMBtu/day and an injection rate of 4,472 MMBtu/day. The 110-day service has injection ratchets 0 to 70% the calculation is 1/170 x MSQ and 70% to 100% the calculation is 1/200 x MSQ. The contract is associated with National Fuel transportation contract (No. N02358). The Company is currently exercising the evergreen provision provided in the contract and is extending the contract on a year to year basis.
EnergyNorth Natural Gas Incorporated	Tennessee	523	FS-MA Storage	21,844	1,560,391	10/31/2010	Part-284 storage service that provides 1,560,391 MMBtu of storage capacity with a withdrawal rate of 21,844 MMBtu/day and an injection rate of 10,404 MMBtu/day or 1/150 of Shipper's MSQ. The contract term has been extended from October 31, 2003 to October 31, 2010.

EnergyNorth Natural Gas Incorporated
Resource Listing

Supply Contracts

Shipper	Supplier	Contract No.	MDCQ	Annual Quantity	Expiration Date	Notes
EnergyNorth Natural Gas Incorporated	BP Canada Energy Company		1,599	583,635	4/1/2007	Supply Agreement between EnergyNorth and BP Canada Energy Company that provides gas commodity from western Canada at the Canadian-US border near Niagra, New York on Tennessee for transportation to EnergyNorth citygates.
EnergyNorth Natural Gas Incorporated	DTE Energy Trading		1,986	724,890	10/31/2007	Supply Agreement between EnergyNorth and DTE Energy Trading that provides gas commodity at the Union Pipeline interconnection at Dawn, Ontario. This contract replaces the ANE contract that expires on October 31, 2006. This contract will commence on November 1, 2006.
EnergyNorth Natural Gas Incorporated	Nexen Marketing		1,600	584,000	4/1/2007	Supply Agreement between EnergyNorth and Nexen Marketing Corporation that provides gas commodity from western Canada at the Canadian-US border near Niagra, New York on Tennessee for transportation to EnergyNorth citygates.
EnergyNorth Natural Gas Incorporated	Sempra Energy Trading		2,106	768,690	10/31/2007	Supply Agreement between EnergyNorth and Sempra Energy Trading that provides gas commodity at the Union Pipeline interconnection at Dawn, Ontario. This contract replaces the former ANE contract. This contract will commence on November 1, 2006

EnergyNorth Natural Gas Incorporated
Resource Listing

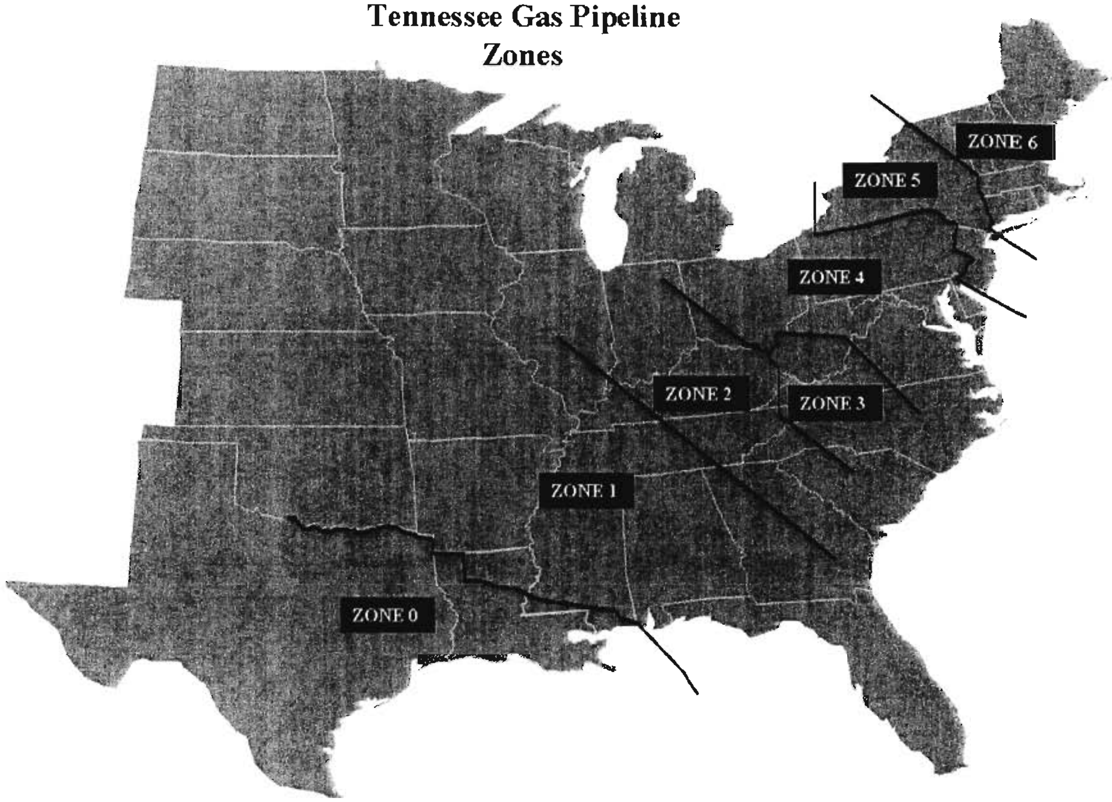
Supplemental Resources

Shipper	Supplier	Contract No.	MDCQ	Annual Quantity	Expiration Date	Notes
EnergyNorth Natural Gas Incorporated	Granite Ridge Energy, L.L.C.		15,000	450,000	9/30/2007	Peaking Supply Agreement between Granite Ridge Energy L.L.C. and EnergyNorth that provides up to 15,000 MMBtu/day for a total of 450,000 MMBtus during the months of December, January and February.
EnergyNorth Natural Gas Incorporated	Distrigas	FLS160	Monthly Take Quantities	1,000,000	10/31/2010	Distrigas of Massachusetts FLS (Firm Liquid Service) is a winter liquid refill contract with an annual quantity of 1,000,000 MMBtu of which 100,000 MMBtus is allocated to EnergyNorth

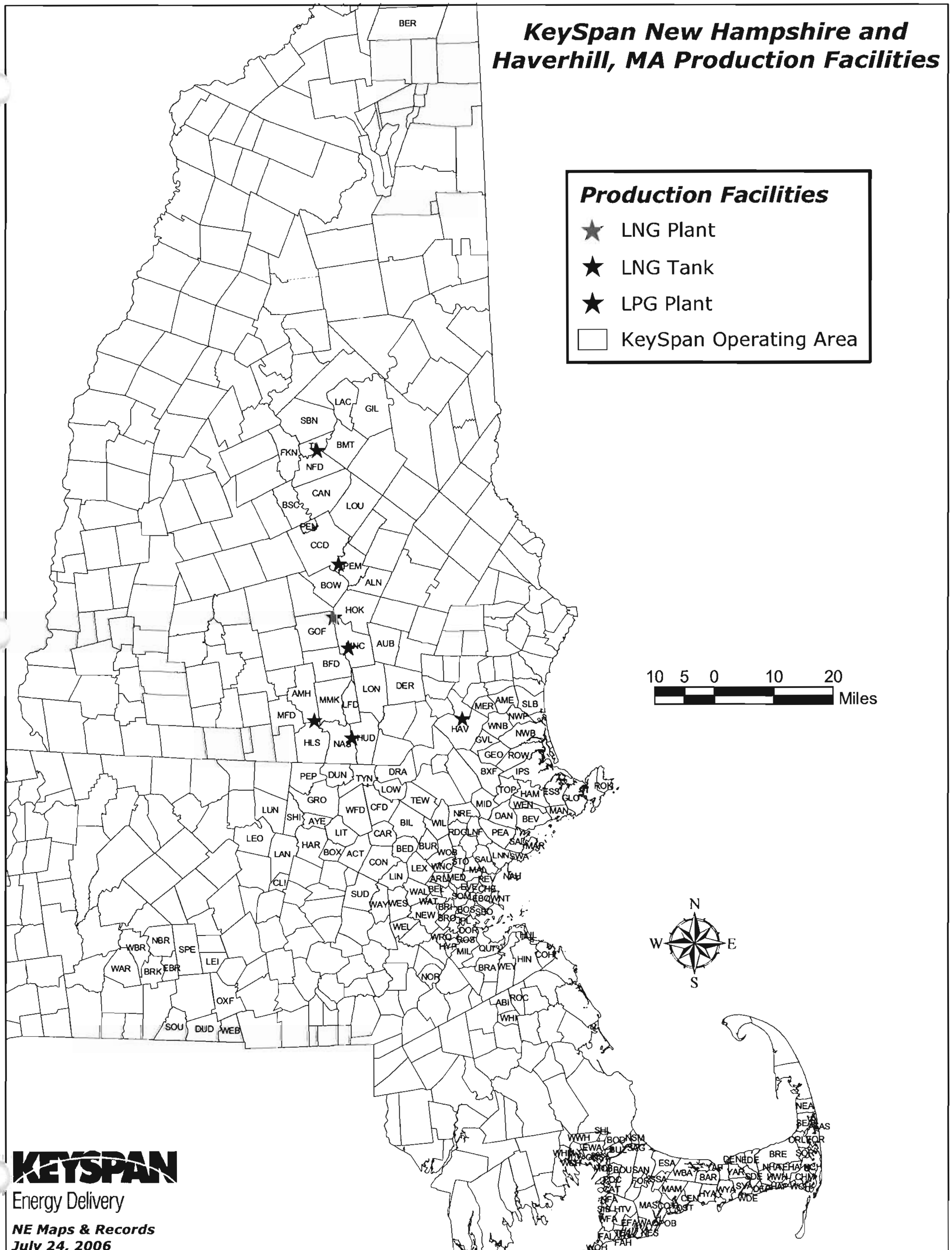
Location	Facility Type	Maximum Vaporization (MMBtu/day)	Storage Capacity (MMBtu/day)
Concord, NH	LNG	4,800	4,200
Tilton, NH	LNG	9,600	4,200
Manchester, NH	LNG	8,400	4,200
Nashua, NH	Propane	11,000	23,672
Amherst, NH	Propane	0	28,450
Manchester, NH	Propane	21,600	47,317
Tilton, NH	Propane	2,000	4,730
Haverhill, MA	Propane	0	42,216

Chart IV-C-3

Tennessee Gas Pipeline Zones



KeySpan New Hampshire and Haverhill, MA Production Facilities



KEYSPAN
Energy Delivery

NE Maps & Records
July 24, 2006

EnergyNorth
Base Case
Resources and Requirements
2006-07 Through 2010-11

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Design Year
(MMBtu)

Heating Season (Nov-Mar)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		10,451,700	10,795,100	10,946,700	11,183,400	11,452,000
Refill	Underground Storage	200	0	0	0	0
	LNG	131,200	138,300	142,800	146,400	148,800
	Propane	93,400	93,400	93,500	93,500	93,500
Total Requirements		10,676,500	11,026,800	11,183,000	11,423,300	11,694,300
RESOURCES						
PNGTS		21,000	21,200	21,000	21,000	21,000
TGP	AES-Londonderry	299,000	405,000	450,000	437,800	450,000
	ANE	584,700	597,200	593,300	593,300	593,300
	BP / Nexen	447,200	450,200	447,200	447,200	450,200
	CoEnergy	1,784,000	1,783,900	1,783,900	1,784,000	1,784,000
	Gulf Supply	3,124,900	3,118,500	3,099,700	3,160,700	3,162,100
	Market Area -- Zone 4	560,300	746,600	802,900	853,500	937,400
	Market Area -- Zone 6	0	0	0	131,500	208,100
	Storage	2,483,900	2,471,600	2,472,400	2,487,700	2,487,700
Other Purchased Resources		0	0	53,300	48,000	128,000
DOMAC	Vapor	842,200	888,700	906,700	898,800	934,200
	Liquid	131,200	138,300	142,800	146,400	148,800
LNG From Storage		138,400	145,500	150,000	153,500	156,000
Propane	Vapor	166,600	166,600	166,700	166,600	140,400
	Truck	93,400	93,400	93,500	93,500	93,500
Total Resources		10,676,800	11,026,700	11,183,400	11,423,500	11,694,700

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Design Year
(MMBtu)

Non-Heating Season (Apr-Oct)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		4,089,700	4,232,000	4,350,800	4,475,400	4,617,800
Refill	Underground Storage	2,564,800	2,552,100	2,552,800	2,568,800	2,568,600
	LNG	27,300	27,300	27,300	27,300	27,300
	Propane	73,300	73,300	73,300	73,300	46,900
Total Requirements		6,755,100	6,884,700	7,004,200	7,144,800	7,260,600
RESOURCES						
PNGTS		12,600	12,600	12,600	12,600	12,600
TGP	AES-Londonderry	0	0	0	0	0
	ANE	840,900	840,900	840,900	840,900	840,900
	BP / Nexen	668,300	668,300	668,300	668,300	665,200
	CoEnergy	0	0	0	0	0
	Gulf Supply	3,920,800	4,382,800	4,431,700	4,467,100	4,510,200
	Market Area -- Zone 4	826,100	540,300	628,800	726,200	863,400
	Market Area -- Zone 6	0	0	0	0	0
	Storage	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	365,800	319,200	301,300	309,200	273,900
	Liquid	27,300	27,300	27,300	27,300	27,300
LNG From Storage		20,000	20,000	20,000	20,000	20,000
Propane	Vapor	0	0	0	0	0
	Truck	73,300	73,300	73,300	73,300	46,900
Total Resources		6,755,100	6,884,700	7,004,200	7,144,900	7,260,400

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Design Year
(MMBtu)

Peak Day

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		138,600	142,000	144,800	147,700	151,000
Refill	Underground Storage	0	0	0	0	0
	LNG	2,000	2,000	2,000	2,000	2,000
	Propane	1,730	8,000	8,000	8,000	0
Total Requirements		142,330	152,000	154,800	157,700	153,000
RESOURCES						
PNGTS		160	160	160	160	160
TGP	AES-Londonderry	15,000	15,000	15,000	15,000	15,000
	ANE	3,970	3,970	3,970	3,970	3,970
	BP / Nexen	3,120	3,120	3,120	3,120	3,120
	CoEnergy	20,000	20,000	20,000	20,000	20,000
	Gulf Supply	21,600	21,600	21,600	21,600	21,600
	Market Area -- Zone 4	0	0	0	0	0
	Market Area -- Zone 6	0	0	0	0	0
	Storage	28,110	28,110	28,110	28,110	28,110
Other Purchased Resources		0	0	0	5,310	19,660
DOMAC	Vapor	8,000	8,000	8,000	8,000	8,000
	Liquid	2,000	2,000	2,000	2,000	2,000
LNG From Storage		3,770	7,100	9,900	7,530	5,810
Propane	Vapor	35,000	35,000	35,000	35,000	25,690
	Truck	1,730	8,000	8,000	8,000	0
Total Resources		142,460	152,060	154,860	157,800	153,120

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Design Year 2006-07
(MMBtu)

REQUIREMENTS		11/2006	12/2006	01/2007	02/2007	03/2007	04/2007	05/2007	06/2007	07/2007	08/2007	09/2007	10/2007
Firm Sendout		1,476,900	2,265,300	2,645,100	2,201,100	1,863,300	1,105,500	644,300	380,800	293,800	291,800	408,700	964,800
Refill	Underground Storage	200	0	0	0	0	465,100	531,300	514,300	531,300	515,100	7,700	0
	LNG	16,200	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	3,700	27,100	62,600	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,493,300	2,283,400	2,712,200	2,299,300	1,888,300	1,570,600	1,210,600	919,900	850,000	817,100	419,200	967,700
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	74,400	150,500	32,100	42,000	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	101,400	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	604,500	619,500	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	640,700	637,700	636,000	574,500	636,000	647,800	669,400	624,800	602,500	584,100	200,600	591,600
	Market Area -- Zone 4	397,600	111,500	0	0	51,200	475,700	282,600	15,300	0	0	0	52,500
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	200	343,600	771,700	677,700	690,700	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	207,500	248,000	144,700	89,900	152,100	229,900	0	39,300	0	0	0	96,600
	Liquid	16,200	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		16,200	18,700	35,700	35,600	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	3,700	63,700	62,600	36,600	0	0	0	0	0	0	0
	Truck	0	3,700	27,100	62,600	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,493,300	2,283,300	2,712,500	2,299,300	1,888,400	1,570,600	1,210,500	919,900	850,000	817,100	419,300	967,700

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Design Year 2007-08
(MMBtu)

REQUIREMENTS		11/2007	12/2007	01/2008	02/2008	03/2008	04/2008	05/2008	06/2008	07/2008	08/2008	09/2008	10/2008
Firm Sendout		1,518,800	2,322,400	2,710,600	2,329,800	1,913,500	1,139,900	667,400	394,300	305,100	303,900	425,600	995,800
Refill	Underground Storage	0	0	0	0	0	46,200	531,300	514,300	531,300	515,100	413,900	0
	LNG	21,100	16,500	40,000	35,700	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	11,600	41,300	40,500	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,539,900	2,350,500	2,791,900	2,406,000	1,938,500	1,186,100	1,233,700	933,400	861,300	829,200	842,300	998,700
RESOURCES													
PNGTS		3,300	4,600	5,100	4,100	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	1,100	81,500	179,200	78,400	64,800	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	113,900	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	66,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	617,200	620,000	546,700	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	595,000	636,000	647,800	669,400	630,400	613,700	596,200	623,600	601,700
	Market Area -- Zone 4	421,000	265,400	0	0	60,200	137,800	305,800	30,200	0	0	0	66,500
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	7,500	218,700	790,800	752,900	701,700	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	237,700	248,000	147,300	96,400	159,300	183,400	0	32,300	0	0	0	103,500
	Liquid	21,100	16,500	40,000	35,700	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		21,100	20,900	35,900	35,400	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	11,600	77,900	40,500	36,600	0	0	0	0	0	0	0
	Truck	0	11,600	41,300	40,500	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,539,900	2,350,500	2,792,000	2,405,900	1,938,400	1,186,200	1,233,700	933,400	861,200	829,200	842,300	998,700

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Design Year 2008-09
(MMBtu)

REQUIREMENTS		11/2008	12/2008	01/2009	02/2009	03/2009	04/2009	05/2009	06/2009	07/2009	08/2009	09/2009	10/2009
Firm Sendout		1,553,900	2,370,400	2,765,600	2,301,100	1,955,700	1,168,800	686,800	405,500	314,400	313,900	439,600	1,021,800
Refill	Underground Storage	0	0	0	0	0	57,000	531,300	501,200	531,300	528,800	403,200	0
	LNG	23,200	19,000	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	54,400	39,100	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,577,100	2,389,400	2,860,000	2,375,800	1,980,700	1,225,800	1,253,100	931,500	870,600	852,900	845,600	1,024,700
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	64,400	197,100	101,600	86,900	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	613,200	618,000	552,700	0	0	0	0	0	0	0	0
	Gulf Supply	617,200	636,000	636,000	574,500	636,000	647,900	669,400	635,000	623,000	619,900	626,900	609,600
	Market Area -- Zone 4	441,700	294,400	0	0	66,800	168,800	325,100	56,000	0	0	0	78,900
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	9,400	226,600	809,000	719,400	708,000	0	0	0	0	0	0	0
Other Purchased Resources		7,600	45,700	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	240,000	248,000	149,100	103,000	166,600	192,100	0	0	0	0	0	109,200
	Liquid	23,200	19,000	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		23,200	19,000	41,900	33,700	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	91,000	39,100	36,600	0	0	0	0	0	0	0
	Truck	0	0	54,400	39,100	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,577,200	2,389,400	2,860,100	2,376,000	1,980,700	1,226,000	1,253,000	931,500	870,500	852,900	845,600	1,024,700

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Design Year 2009-10
(MMBtu)

REQUIREMENTS		11/2009	12/2009	01/2010	02/2010	03/2010	04/2010	05/2010	06/2010	07/2010	08/2010	09/2010	10/2010
Firm Sendout		1,590,800	2,420,600	2,823,200	2,348,900	1,999,900	1,199,100	707,100	417,200	324,200	324,500	454,300	1,049,000
Refill	Underground Storage	0	0	0	0	0	85,300	531,300	500,100	531,300	529,300	391,500	0
	LNG	25,000	20,100	40,000	36,300	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	89,300	4,200	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,615,800	2,440,700	2,952,500	2,389,400	2,024,900	1,284,400	1,273,400	942,100	880,400	864,000	848,600	1,051,900
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	90,000	222,700	125,100	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	604,000	620,000	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	644,700	669,500	636,000	574,500	636,000	647,900	669,400	638,800	632,900	630,900	629,900	617,300
	Market Area -- Zone 4	463,600	313,300	0	0	76,600	225,900	345,500	62,900	0	0	0	91,900
	Market Area – Zone 6	17,100	0	0	0	114,400	0	0	0	0	0	0	0
	Storage	9,400	216,800	822,300	731,400	707,800	0	0	0	0	0	0	0
Other Purchased Resources		0	32,100	15,900	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	216,200	248,000	152,900	108,200	173,500	193,500	0	0	0	0	0	115,700
	Liquid	25,000	20,100	40,000	36,300	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		25,000	23,900	40,700	31,700	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	89,300	40,700	36,600	0	0	0	0	0	0	0
	Truck	0	0	89,300	4,200	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,615,900	2,440,800	2,952,700	2,389,400	2,024,700	1,284,500	1,273,400	942,200	880,400	863,900	848,600	1,051,900

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Design Year 2010-11
(MMBtu)

REQUIREMENTS		11/2010	12/2010	01/2011	02/2011	03/2011	04/2011	05/2011	06/2011	07/2011	08/2011	09/2011	10/2011
Firm Sendout		1,632,600	2,477,600	2,888,600	2,403,200	2,050,000	1,233,600	730,300	430,700	335,500	336,600	471,100	1,080,000
Refill	Underground Storage	0	0	0	0	0	98,600	531,300	499,200	531,300	530,100	378,100	0
	LNG	25,000	21,300	40,000	37,500	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	42,400	51,100	0	0	22,000	22,000	2,900	0	0	0
Total Requirements		1,657,600	2,498,900	2,971,000	2,491,800	2,075,000	1,332,200	1,296,600	954,700	872,600	869,600	852,000	1,082,900
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	68,100	242,300	139,600	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	66,400	96,700	93,700	96,800	90,600	96,800	96,800	93,700	96,800
	CoEnergy	0	604,000	620,000	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	646,100	669,500	636,000	574,500	636,000	647,800	669,400	645,900	644,200	643,800	633,400	625,700
	Market Area -- Zone 4	486,400	369,100	0	0	81,900	315,700	368,600	71,400	0	0	0	107,700
	Market Area -- Zone 6	32,700	0	0	0	175,400	0	0	0	0	0	0	0
	Storage	9,400	197,500	836,100	748,000	696,700	0	0	0	0	0	0	0
Other Purchased Resources		0	77,000	51,000	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	218,200	248,000	160,100	113,000	194,900	151,500	0	0	0	0	0	122,400
	Liquid	25,000	21,300	40,000	37,500	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		25,000	21,300	40,700	36,800	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	79,000	51,100	10,300	0	0	0	0	0	0	0
	Truck	0	0	42,400	51,100	0	0	22,000	22,000	2,900	0	0	0
Total Resources		1,657,700	2,498,900	2,971,200	2,491,900	2,075,000	1,332,200	1,296,500	954,700	872,600	869,500	852,100	1,082,800

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Normal Year
(MMBtu)

Heating Season (Nov-Mar)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		9,441,300	9,757,800	9,904,300	10,125,700	10,377,200
Refill	Underground Storage	600	0	0	0	0
	LNG	65,600	114,400	122,300	125,000	131,200
	Propane	93,500	93,500	93,500	93,500	93,400
Total Requirements		9,601,000	9,965,700	10,120,100	10,344,200	10,601,800
RESOURCES						
PNGTS		21,000	21,200	21,000	21,000	21,000
TGP	AES-Londonderry	0	12,100	70,900	111,500	178,100
	ANE	584,700	588,600	593,300	593,300	593,300
	BP / Nexen	447,200	450,200	447,200	447,200	447,200
	CoEnergy	1,784,000	1,784,100	1,784,000	1,784,000	1,784,000
	Gulf Supply	3,098,000	3,118,500	3,098,000	3,122,800	3,129,600
	Market Area -- Zone 4	327,500	360,100	382,800	435,700	549,700
	Market Area -- Zone 6	0	0	0	34,600	92,000
	Storage	2,406,300	2,488,400	2,475,300	2,487,700	2,471,700
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	538,900	646,800	736,100	789,400	842,600
	Liquid	65,600	114,400	122,300	125,000	131,200
LNG From Storage		72,900	121,500	129,500	132,200	138,400
Propane	Vapor	161,800	166,700	166,700	166,700	130,000
	Truck	93,500	93,500	93,500	93,500	93,400
Total Resources		9,601,400	9,966,100	10,120,600	10,344,600	10,602,200

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Normal Year
(MMBtu)

Non-Heating Season (Apr-Oct)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		3,813,000	3,950,100	4,064,600	4,184,600	4,321,900
Refill	Underground Storage	2,483,600	2,569,500	2,556,000	2,568,700	2,551,900
	LNG	27,300	27,300	27,300	27,300	27,300
	Propane	68,400	73,300	73,300	73,300	36,600
Total Requirements		6,392,300	6,620,200	6,721,200	6,853,900	6,937,700
RESOURCES						
PNGTS		12,600	12,600	12,600	12,600	12,600
TGP	AES-Londonderry	0	0	0	0	0
	ANE	840,900	840,900	840,900	840,900	840,900
	BP / Nexen	668,300	668,300	668,300	668,300	668,300
	CoEnergy	0	0	0	0	0
	Gulf Supply	3,679,900	4,230,200	4,380,500	4,436,200	4,478,800
	Market Area -- Zone 4	405,900	186,300	226,300	356,700	487,800
	Market Area -- Zone 6	0	0	0	0	0
	Storage	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	669,100	561,200	472,000	418,600	365,400
	Liquid	27,300	27,300	27,300	27,300	27,300
LNG From Storage		20,000	20,000	20,000	20,000	20,000
Propane	Vapor	0	0	0	0	0
	Truck	68,400	73,300	73,300	73,300	36,600
Total Resources		6,392,400	6,620,100	6,721,200	6,853,900	6,937,700

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Normal Year 2006-07
(MMBtu)

REQUIREMENTS		11/2006	12/2006	01/2007	02/2007	03/2007	04/2007	05/2007	06/2007	07/2007	08/2007	09/2007	10/2007
Firm Sendout		1,347,600	2,052,800	2,366,400	1,956,700	1,717,800	1,004,100	620,600	340,800	293,000	289,700	381,000	883,800
Refill	Underground Storage	600	0	0	0	0	396,600	531,300	514,300	531,300	502,400	7,700	0
	LNG	3,800	14,400	22,400	0	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	17,100	76,400	0	0	0	22,000	22,000	22,000	2,400	0	0
Total Requirements		1,352,000	2,084,300	2,465,200	1,956,700	1,742,800	1,400,700	1,186,900	879,900	849,200	797,400	391,500	886,700
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	0	0	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	101,400	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	610,200	618,700	555,100	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	574,500	636,000	647,800	669,400	620,800	601,700	569,300	172,800	398,100
	Market Area -- Zone 4	298,000	0	0	0	29,500	304,600	79,100	0	0	0	0	22,200
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	600	499,900	690,300	559,100	656,400	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	215,500	45,500	105,100	53,400	119,400	231,200	179,800	18,700	0	0	0	239,400
	Liquid	3,800	14,400	22,400	0	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		3,800	21,100	15,700	10,100	22,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	17,100	77,100	35,900	31,700	0	0	0	0	0	0	0
	Truck	0	17,100	76,400	0	0	0	22,000	22,000	22,000	2,400	0	0
Total Resources		1,352,100	2,084,400	2,465,300	1,956,800	1,742,800	1,400,800	1,186,800	880,000	849,200	797,400	391,500	886,700

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Normal Year 2007-08
(MMBtu)

REQUIREMENTS		11/2007	12/2007	01/2008	02/2008	03/2008	04/2008	05/2008	06/2008	07/2008	08/2008	09/2008	10/2008
Firm Sendout		1,386,900	2,106,300	2,427,300	2,072,500	1,764,800	1,036,800	642,700	354,100	304,300	301,700	397,300	913,200
Refill	Underground Storage	0	0	0	0	0	124,000	531,300	514,300	531,300	513,000	355,600	0
	LNG	5,700	14,400	37,300	32,000	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	15,800	48,200	29,500	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,392,600	2,136,500	2,512,800	2,134,000	1,789,800	1,160,800	1,209,000	893,200	860,500	824,900	755,700	916,100
RESOURCES													
PNGTS		3,300	4,600	5,100	4,100	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	12,100	0	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	105,300	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	66,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	608,800	610,300	565,000	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	595,000	636,000	647,900	669,400	627,300	612,900	591,900	537,000	543,800
	Market Area – Zone 4	321,500	0	0	0	38,600	63,200	93,700	0	0	0	0	29,400
	Market Area – Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	7,500	481,600	720,400	617,500	661,400	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	221,900	106,800	121,600	60,100	136,400	232,600	187,400	25,400	0	0	0	115,800
	Liquid	5,700	14,400	37,300	32,000	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		5,700	18,200	39,000	29,700	28,900	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	19,700	76,600	29,500	40,900	0	0	0	0	0	0	0
	Truck	0	15,800	48,200	29,500	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,392,700	2,136,500	2,513,000	2,134,100	1,789,800	1,160,900	1,209,000	893,200	860,400	824,900	755,700	916,000

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Normal Year 2008-09
(MMBtu)

REQUIREMENTS		11/2008	12/2008	01/2009	02/2009	03/2009	04/2009	05/2009	06/2009	07/2009	08/2009	09/2009	10/2009
Firm Sendout		1,420,000	2,151,200	2,478,500	2,050,300	1,804,300	1,064,200	681,200	365,200	313,600	311,700	410,900	937,800
Refill	Underground Storage	0	0	0	0	0	43,600	531,300	510,400	531,300	522,900	416,500	0
	LNG	7,300	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	56,000	37,500	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,427,300	2,165,600	2,574,500	2,123,400	1,829,300	1,107,800	1,227,500	900,400	869,800	844,800	830,200	940,700
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	45,000	9,200	0	16,700	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	68,900	91,200	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	617,600	620,000	546,400	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	574,500	636,000	647,800	669,400	632,500	622,300	611,700	611,500	585,300
	Market Area -- Zone 4	345,200	0	0	0	37,600	81,100	106,900	0	0	0	0	38,300
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	9,400	443,100	727,700	608,600	686,500	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	227,800	169,900	131,200	65,600	141,600	161,700	192,700	27,500	0	0	0	90,100
	Liquid	7,300	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		7,300	16,500	38,500	35,000	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	92,600	37,500	36,600	0	0	0	0	0	0	0
	Truck	0	0	56,000	37,500	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,427,400	2,165,600	2,574,800	2,123,500	1,829,300	1,107,800	1,227,500	900,500	869,800	844,700	830,200	940,700

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Normal Year 2009-10
(MMBtu)

REQUIREMENTS		11/2009	12/2009	01/2010	02/2010	03/2010	04/2010	05/2010	06/2010	07/2010	08/2010	09/2010	10/2010
Firm Sendout		1,454,600	2,198,300	2,532,100	2,095,000	1,845,700	1,092,900	680,600	376,800	323,400	322,200	425,100	963,600
Refill	Underground Storage	0	0	0	0	0	56,900	531,300	502,200	531,300	527,200	419,800	0
	LNG	10,000	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	42,100	51,400	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,464,600	2,212,700	2,614,200	2,182,000	1,870,700	1,149,800	1,246,900	903,800	879,600	859,600	847,700	966,500
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	59,400	52,100	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	609,400	615,400	559,200	0	0	0	0	0	0	0	0
	Gulf Supply	640,300	636,000	636,000	574,500	636,000	647,900	669,400	637,300	632,100	626,500	629,100	593,900
	Market Area – Zone 4	371,600	13,800	0	0	50,300	100,600	207,600	0	0	0	0	48,500
	Market Area -- Zone 6	0	0	0	0	34,600	0	0	0	0	0	0	0
	Storage	9,400	418,700	750,100	625,800	683,700	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	208,500	223,500	136,400	71,400	149,600	184,200	111,400	26,000	0	0	0	97,000
	Liquid	10,000	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		10,000	14,400	40,000	35,600	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	78,700	51,400	36,600	0	0	0	0	0	0	0
	Truck	0	0	42,100	51,400	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,464,700	2,212,700	2,614,400	2,182,200	1,870,600	1,149,900	1,246,900	903,800	879,600	859,500	847,800	966,400

COMPARISON OF RESOURCES AND REQUIREMENTS
Base Case Normal Year 2010-11
(MMBtu)

REQUIREMENTS		11/2010	12/2010	01/2011	02/2011	03/2011	04/2011	05/2011	06/2011	07/2011	08/2011	09/2011	10/2011
Firm Sendout		1,493,900	2,251,700	2,593,000	2,145,900	1,892,700	1,125,500	702,800	390,200	334,700	334,200	441,500	993,000
Refill	Underground Storage	0	0	0	0	0	53,000	531,300	500,600	531,300	528,700	407,000	0
	LNG	16,200	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	600	24,500	68,300	0	0	22,000	14,600	0	0	0	0
Total Requirements		1,510,100	2,266,700	2,657,500	2,249,800	1,917,700	1,178,500	1,269,100	908,200	868,900	865,800	851,300	995,900
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	72,700	105,400	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	604,000	620,000	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	641,900	641,200	636,000	574,500	636,000	647,800	669,400	642,200	643,400	640,100	632,600	603,300
	Market Area – Zone 4	399,700	97,600	0	0	52,400	122,700	303,900	0	0	0	0	61,200
	Market Area -- Zone 6	0	0	0	0	92,000	0	0	0	0	0	0	0
	Storage	9,400	350,200	764,600	647,900	699,600	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	211,900	248,000	142,400	82,400	157,900	190,900	37,200	32,900	0	0	0	104,400
	Liquid	16,200	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		16,200	14,400	40,000	35,600	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	600	61,100	68,300	0	0	0	0	0	0	0	0
	Truck	0	600	24,500	68,300	0	0	22,000	14,600	0	0	0	0
Total Resources		1,510,200	2,266,800	2,657,600	2,249,900	1,917,700	1,178,600	1,269,000	908,200	868,900	865,800	851,300	995,900

EnergyNorth
High Case
Resources and Requirements
2006-07 Through 2010-11

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Design Year
(MMBtu)

Heating Season (Nov-Mar)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		10,764,700	11,221,900	11,458,800	11,786,400	12,147,900
Refill	Underground Storage	2,400	0	0	0	0
	LNG	139,400	147,900	150,000	150,000	150,000
	Propane	93,400	93,500	93,500	93,500	93,500
Total Requirements		10,999,900	11,463,300	11,702,300	12,029,900	12,391,400
RESOURCES						
PNGTS		21,000	21,200	21,000	21,000	21,000
TGP	AES-Londonderry	424,100	450,100	450,100	450,000	450,000
	ANE	584,700	597,200	593,300	593,300	593,300
	BP / Nexen	447,200	450,200	447,200	471,200	469,500
	CoEnergy	1,784,000	1,783,900	1,784,000	1,784,000	1,784,000
	Gulf Supply	3,149,400	3,123,500	3,107,100	3,163,200	3,163,900
	Market Area -- Zone 4	705,900	921,300	972,700	1,008,700	1,105,600
	Market Area -- Zone 6	0	0	0	249,200	343,900
	Storage	2,470,100	2,487,700	2,487,700	2,487,600	2,487,700
Other Purchased Resources		0	145,000	311,600	245,700	376,400
DOMAC	Vapor	867,800	920,300	960,800	988,800	1,035,300
	Liquid	139,400	147,900	150,000	150,000	150,000
LNG From Storage		146,600	155,200	157,300	157,200	157,300
Propane	Vapor	166,600	166,700	166,700	166,700	160,200
	Truck	93,400	93,500	93,500	93,500	93,500
Total Resources		11,000,200	11,463,700	11,703,000	12,030,100	12,391,600

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Design Year
(MMBtu)

Non-Heating Season (Apr-Oct)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		4,264,200	4,469,300	4,638,200	4,814,700	5,009,900
Refill	Underground Storage	2,548,200	2,568,800	2,568,900	2,568,900	2,568,700
	LNG	27,300	27,300	27,300	27,300	27,300
	Propane	73,300	73,300	73,300	73,300	66,900
Total Requirements		6,913,000	7,138,700	7,307,700	7,484,200	7,672,800
RESOURCES						
PNGTS		12,600	12,600	12,600	12,600	12,600
TGP	AES-Londonderry	0	0	0	0	0
	ANE	840,900	840,900	840,900	840,900	840,900
	BP / Nexen	668,300	668,300	668,300	644,200	645,800
	CoEnergy	0	0	0	0	0
	Gulf Supply	3,991,900	4,455,500	4,517,500	4,583,300	4,613,300
	Market Area -- Zone 4	938,200	753,000	900,400	1,063,200	1,273,000
	Market Area -- Zone 6	0	0	0	0	0
	Storage	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	340,200	287,700	247,300	219,100	172,700
	Liquid	27,300	27,300	27,300	27,300	27,300
LNG From Storage		20,000	20,000	20,000	20,000	20,000
Propane	Vapor	0	0	0	0	0
	Truck	73,300	73,300	73,300	73,300	66,900
Total Resources		6,912,700	7,138,600	7,307,600	7,483,900	7,672,500

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Design Year
(MMBtu)

Peak Day

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		143,000	147,700	151,500	155,600	160,000
Refill	Underground Storage	0	0	0	0	0
	LNG	2,000	2,000	2,000	2,000	2,000
	Propane	4,640	0	0	0	0
Total Requirements		149,640	149,700	153,500	157,600	162,000
RESOURCES						
PNGTS		160	160	160	160	160
TGP	AES-Londonderry	15,000	15,000	15,000	15,000	15,000
	ANE	3,970	3,970	3,970	3,970	3,970
	BP / Nexen	3,120	3,120	3,120	3,120	3,120
	CoEnergy	20,000	20,000	20,000	20,000	20,000
	Gulf Supply	21,600	21,600	21,600	21,600	21,600
	Market Area -- Zone 4	0	0	0	0	0
	Market Area -- Zone 6	0	0	0	0	0
	Storage	28,110	28,110	28,110	28,110	28,110
Other Purchased Resources		0	730	22,140	40,000	40,000
DOMAC	Vapor	8,000	8,000	8,000	8,000	8,000
	Liquid	2,000	2,000	2,000	2,000	2,000
LNG From Storage		8,100	12,060	2,000	5,810	12,060
Propane	Vapor	35,000	35,000	27,510	9,880	8,080
	Truck	4,640	0	0	0	0
Total Resources		149,700	149,750	153,610	157,650	162,100

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Design Year 2006-07
(MMBtu)

REQUIREMENTS		11/2006	12/2006	01/2007	02/2007	03/2007	04/2007	05/2007	06/2007	07/2007	08/2007	09/2007	10/2007
Firm Sendout		1,525,700	2,331,600	2,721,700	2,264,200	1,921,500	1,146,100	672,400	398,100	308,700	307,600	429,700	1,001,600
Refill	Underground Storage	2,400	0	0	0	0	448,500	531,300	514,300	531,300	515,100	7,700	0
	LNG	22,000	16,800	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	13,100	44,600	35,700	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,550,100	2,361,500	2,806,300	2,335,500	1,946,500	1,594,600	1,238,700	937,200	864,900	832,900	440,200	1,004,500
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	2,300	82,300	183,400	87,700	68,400	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	101,400	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	604,000	620,000	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	642,400	660,500	636,000	574,500	636,000	647,900	669,400	632,200	617,300	599,900	221,500	603,700
	Market Area -- Zone 4	430,000	216,600	0	0	59,300	497,900	310,700	60,700	0	0	0	68,900
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	2,400	262,600	793,900	705,200	706,000	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	214,300	248,000	147,600	97,600	160,300	231,600	0	3,800	0	0	0	104,800
	Liquid	22,000	16,800	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		22,000	21,400	36,100	34,900	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	13,100	81,200	35,700	36,600	0	0	0	0	0	0	0
	Truck	0	13,100	44,600	35,700	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,550,300	2,361,500	2,806,400	2,335,600	1,946,400	1,594,600	1,238,600	937,200	864,800	832,900	440,200	1,004,400

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Design Year 2007-08
(MMBtu)

REQUIREMENTS		11/2007	12/2007	01/2008	02/2008	03/2008	04/2008	05/2008	06/2008	07/2008	08/2008	09/2008	10/2008
Firm Sendout		1,585,100	2,412,200	2,814,000	2,418,100	1,992,500	1,195,100	705,700	417,800	325,400	325,400	454,100	1,045,800
Refill	Underground Storage	0	0	0	0	0	84,700	531,300	514,300	531,300	515,100	392,100	0
	LNG	25,000	21,800	40,000	36,100	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	69,500	24,000	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,610,100	2,434,000	2,923,500	2,478,200	2,017,500	1,279,800	1,272,000	956,900	881,600	850,700	849,000	1,048,700
RESOURCES													
PNGTS		3,300	4,600	5,100	4,100	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	4,600	214,800	121,500	109,200	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	113,900	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	66,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	584,000	619,900	580,000	0	0	0	0	0	0	0	0
	Gulf Supply	620,500	636,000	636,000	595,000	636,000	647,900	669,400	639,300	634,000	617,700	630,400	616,800
	Market Area -- Zone 4	462,400	380,200	0	0	78,700	242,000	344,000	77,100	0	0	0	89,900
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	7,500	197,700	820,200	757,700	704,600	0	0	0	0	0	0	0
Other Purchased Resources		13,100	118,500	13,400	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	240,000	248,000	151,900	107,800	172,600	172,800	0	0	0	0	0	114,900
	Liquid	25,000	21,800	40,000	36,100	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		26,800	20,100	44,200	31,900	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	90,200	39,900	36,600	0	0	0	0	0	0	0
	Truck	0	0	69,500	24,000	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,610,200	2,434,000	2,923,700	2,478,300	2,017,500	1,279,900	1,271,900	956,900	881,500	850,700	849,100	1,048,600

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Design Year 2008-09
(MMBtu)

REQUIREMENTS		11/2008	12/2008	01/2009	02/2009	03/2009	04/2009	05/2009	06/2009	07/2009	08/2009	09/2009	10/2009
Firm Sendout		1,634,200	2,478,800	2,890,300	2,404,300	2,051,200	1,235,600	733,100	434,000	339,000	340,000	474,200	1,082,300
Refill	Underground Storage	0	0	0	0	0	100,700	531,300	499,500	531,300	529,900	376,200	0
	LNG	25,000	22,500	40,000	37,500	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	53,500	40,000	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,659,200	2,501,300	2,983,800	2,481,800	2,076,200	1,336,300	1,299,400	958,300	895,200	880,100	853,200	1,085,200
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	0	242,400	139,700	68,000	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	604,000	620,000	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	624,600	636,000	636,000	574,500	636,000	647,900	669,400	644,200	647,700	647,100	634,500	626,700
	Market Area – Zone 4	487,400	403,400	0	0	81,900	347,100	371,400	73,600	0	0	0	108,300
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	9,400	197,500	836,400	750,300	694,100	0	0	0	0	0	0	0
Other Purchased Resources		31,800	145,500	52,700	0	81,600	0	0	0	0	0	0	0
DOMAC	Vapor	240,000	248,000	160,200	114,300	198,300	124,200	0	0	0	0	0	123,100
	Liquid	25,000	22,500	40,000	37,500	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		26,200	21,400	41,700	35,800	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	77,500	52,600	36,600	0	0	0	0	0	0	0
	Truck	0	0	53,500	40,000	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,659,300	2,501,400	2,984,000	2,482,000	2,076,300	1,336,400	1,299,300	958,300	895,200	880,100	853,200	1,085,100

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Design Year 2009-10
(MMBtu)

REQUIREMENTS		11/2009	12/2009	01/2010	02/2010	03/2010	04/2010	05/2010	06/2010	07/2010	08/2010	09/2010	10/2010
Firm Sendout		1,685,400	2,548,300	2,969,800	2,470,500	2,112,400	1,277,800	761,800	450,900	353,300	355,300	495,200	1,120,400
Refill	Underground Storage	0	0	0	0	0	118,800	531,300	503,400	530,200	526,100	359,100	0
	LNG	25,000	24,500	40,000	35,500	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	29,500	64,000	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,710,400	2,572,800	3,039,300	2,570,000	2,137,400	1,396,600	1,328,100	979,100	908,400	891,600	857,100	1,123,300
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	33,200	262,100	154,700	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	87,400	96,700	93,700	96,800	93,700	88,200	85,800	89,200	96,800
	CoEnergy	0	604,000	620,000	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	647,200	669,500	636,000	574,500	636,000	647,900	669,400	647,900	669,400	669,500	642,900	636,300
	Market Area -- Zone 4	513,700	412,700	0	0	82,300	444,600	400,100	90,700	0	0	0	127,800
	Market Area -- Zone 6	54,400	0	0	0	194,800	0	0	0	0	0	0	0
	Storage	9,400	197,500	850,700	743,200	686,800	0	0	0	0	0	0	0
Other Purchased Resources		0	135,800	109,900	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	220,800	248,000	169,800	127,100	223,100	87,000	0	0	0	0	0	132,100
	Liquid	25,000	24,500	40,000	35,500	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		25,000	24,500	48,000	29,500	30,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	49,900	80,200	36,600	0	0	0	0	0	0	0
	Truck	0	0	29,500	64,000	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,710,400	2,572,800	3,039,500	2,570,000	2,137,400	1,396,700	1,328,000	979,100	908,300	891,500	857,100	1,123,200

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Design Year 2010-11
(MMBtu)

REQUIREMENTS		11/2010	12/2010	01/2011	02/2011	03/2011	04/2011	05/2011	06/2011	07/2011	08/2011	09/2011	10/2011
Firm Sendout		1,741,900	2,625,000	3,057,600	2,543,400	2,180,000	1,324,400	793,500	469,700	369,200	372,300	518,400	1,162,400
Refill	Underground Storage	0	0	0	0	0	139,300	531,300	514,200	523,300	519,400	341,200	0
	LNG	20,800	34,900	40,000	29,300	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	0	93,500	0	0	22,000	22,000	22,000	900	0	0
Total Requirements		1,762,700	2,659,900	3,097,600	2,666,200	2,205,000	1,463,700	1,359,800	1,008,700	917,400	895,500	862,400	1,165,300
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	7,200	272,700	170,100	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	85,700	96,700	93,700	96,800	93,700	96,800	96,200	88,500	80,100
	CoEnergy	0	604,000	620,000	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	647,900	669,500	636,000	574,500	636,000	647,800	669,400	648,000	669,400	669,400	647,800	661,500
	Market Area -- Zone 4	538,600	450,700	0	0	116,300	571,600	431,600	120,200	400	0	0	149,200
	Market Area -- Zone 6	87,000	0	0	0	256,900	0	0	0	0	0	0	0
	Storage	9,400	197,500	865,200	754,900	660,700	0	0	0	0	0	0	0
Other Purchased Resources		0	190,100	186,300	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	223,300	248,000	181,400	147,500	235,100	27,200	200	0	0	0	1,100	144,200
	Liquid	20,800	34,900	40,000	29,300	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		20,800	34,900	40,000	39,400	22,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	32,600	97,400	30,200	0	0	0	0	0	0	0
	Truck	0	0	0	93,500	0	0	22,000	22,000	22,000	900	0	0
Total Resources		1,762,700	2,659,900	3,097,800	2,666,200	2,205,000	1,463,800	1,359,700	1,008,700	917,300	895,400	862,400	1,165,200

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Normal Year
(MMBtu)

Heating Season (Nov-Mar)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		9,691,000	10,114,200	10,341,000	10,647,900	10,986,400
Refill	Underground Storage	600	0	0	0	0
	LNG	114,100	123,500	130,100	137,700	143,900
	Propane	93,500	93,500	93,400	93,400	93,500
Total Requirements		9,899,200	10,331,200	10,564,500	10,879,000	11,223,800
RESOURCES						
PNGTS		21,000	21,200	21,000	21,000	21,000
TGP	AES-Londonderry	11,100	118,000	219,000	253,500	356,100
	ANE	584,700	597,200	593,300	593,300	593,300
	BP / Nexen	447,200	450,200	447,200	447,200	447,200
	CoEnergy	1,783,900	1,784,000	1,784,000	1,784,000	1,784,000
	Gulf Supply	3,098,000	3,118,500	3,098,000	3,133,800	3,161,400
	Market Area -- Zone 4	358,200	420,900	530,500	678,500	810,300
	Market Area -- Zone 6	0	0	0	82,400	161,600
	Storage	2,451,700	2,487,900	2,486,900	2,474,700	2,471,500
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	648,200	819,300	857,600	868,600	892,900
	Liquid	114,100	123,500	130,100	137,700	143,900
LNG From Storage		121,200	130,700	137,300	144,900	151,200
Propane	Vapor	166,700	166,700	166,600	166,600	136,200
	Truck	93,500	93,500	93,400	93,400	93,500
Total Resources		9,899,500	10,331,600	10,564,900	10,879,600	11,224,100

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Normal Year
(MMBtu)

Non-Heating Season (Apr-Oct)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		3,957,600	4,155,700	4,318,400	4,488,600	4,677,000
Refill	Underground Storage	2,530,800	2,569,100	2,567,900	2,555,200	2,552,200
	LNG	27,300	27,300	27,300	27,300	27,300
	Propane	73,300	73,300	73,300	73,300	42,700
Total Requirements		6,589,000	6,825,400	6,986,900	7,144,400	7,299,200
RESOURCES						
PNGTS		12,600	12,600	12,600	12,600	12,600
TGP	AES-Londonderry	0	0	0	0	0
	ANE	840,900	840,900	840,900	840,900	840,900
	BP / Nexen	668,300	668,300	668,300	668,300	668,300
	CoEnergy	0	0	0	0	0
	Gulf Supply	3,890,200	4,420,300	4,482,600	4,531,900	4,568,500
	Market Area -- Zone 4	496,400	373,900	511,500	630,600	803,600
	Market Area -- Zone 6	0	0	0	0	0
	Storage	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	559,800	388,800	350,400	339,600	315,000
	Liquid	27,300	27,300	27,300	27,300	27,300
LNG From Storage		20,000	20,000	20,000	20,000	20,000
Propane	Vapor	0	0	0	0	0
	Truck	73,300	73,300	73,300	73,300	42,700
Total Resources		6,588,800	6,825,400	6,986,900	7,144,500	7,298,900

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Normal Year 2006-07
(MMBtu)

REQUIREMENTS		11/2006	12/2006	01/2007	02/2007	03/2007	04/2007	05/2007	06/2007	07/2007	08/2007	09/2007	10/2007
Firm Sendout		1,387,100	2,105,800	2,426,500	2,007,000	1,764,600	1,037,200	643,700	355,400	305,800	303,200	398,500	913,800
Refill	Underground Storage	600	0	0	0	0	433,300	531,300	514,300	531,300	512,900	7,700	0
	LNG	5,700	14,400	37,300	31,700	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	18,600	74,900	0	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,393,400	2,138,800	2,538,700	2,038,700	1,789,600	1,470,500	1,210,000	894,500	862,000	826,300	409,000	916,700
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	11,100	0	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	101,400	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	73,800	86,300	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	607,300	620,000	556,600	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	574,500	636,000	647,800	669,400	628,200	614,400	593,200	190,300	546,900
	Market Area -- Zone 4	328,400	0	0	0	29,800	372,900	94,100	0	0	0	0	29,400
	Market Area – Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	600	476,400	710,500	578,000	686,200	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	222,700	113,200	121,400	60,000	130,900	232,700	187,900	25,900	0	0	0	113,300
	Liquid	5,700	14,400	37,300	31,700	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		5,700	20,100	37,000	29,500	28,900	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	18,600	78,100	29,300	40,700	0	0	0	0	0	0	0
	Truck	0	18,600	74,900	0	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,393,500	2,138,800	2,538,800	2,038,700	1,789,700	1,470,600	1,209,900	894,600	861,900	826,200	409,000	916,600

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Normal Year 2007-08
(MMBtu)

REQUIREMENTS		11/2007	12/2007	01/2008	02/2008	03/2008	04/2008	05/2008	06/2008	07/2008	08/2008	09/2008	10/2008
Firm Sendout		1,442,900	2,181,400	2,512,500	2,146,100	1,831,300	1,083,700	675,600	375,000	322,500	320,900	422,200	955,800
Refill	Underground Storage	0	0	0	0	0	53,400	531,300	514,300	531,300	516,300	422,500	0
	LNG	8,400	14,400	40,000	35,700	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	45,000	48,500	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,451,300	2,195,800	2,597,500	2,230,300	1,856,300	1,137,100	1,241,900	914,100	878,700	847,400	847,500	958,700
RESOURCES													
PNGTS		3,300	4,600	5,100	4,100	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	54,800	35,200	0	28,000	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	113,900	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	73,400	89,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	584,900	619,100	580,000	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	595,000	636,000	647,900	669,400	637,000	631,100	614,400	628,800	591,700
	Market Area -- Zone 4	364,700	13,100	0	0	43,100	94,100	234,700	0	0	0	0	45,100
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	7,500	418,600	740,100	629,200	692,500	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	232,100	236,600	134,500	68,900	147,200	178,100	79,200	36,600	0	0	0	94,900
	Liquid	8,400	14,400	40,000	35,700	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		8,400	14,400	42,600	33,100	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	81,600	48,500	36,600	0	0	0	0	0	0	0
	Truck	0	0	45,000	48,500	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,451,500	2,195,900	2,597,700	2,230,300	1,856,200	1,137,300	1,241,800	914,100	878,600	847,400	847,500	958,700

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Normal Year 2008-09
(MMBtu)

REQUIREMENTS		11/2008	12/2008	01/2009	02/2009	03/2009	04/2009	05/2009	06/2009	07/2009	08/2009	09/2009	10/2009
Firm Sendout		1,489,000	2,243,900	2,583,600	2,138,200	1,886,300	1,122,100	701,800	391,000	336,100	335,400	441,600	990,400
Refill	Underground Storage	0	0	0	0	0	68,500	531,300	500,400	531,300	529,000	407,400	0
	LNG	15,100	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	28,200	65,200	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,504,100	2,258,300	2,651,800	2,239,000	1,911,300	1,190,600	1,268,100	916,200	892,300	874,600	851,800	993,300
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	71,100	95,700	0	52,200	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	604,000	620,000	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	574,500	636,000	647,900	669,400	642,800	644,800	641,600	633,200	602,900
	Market Area -- Zone 4	396,200	81,300	0	0	53,000	120,000	331,900	0	0	0	0	59,600
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	9,400	373,900	762,100	644,800	696,700	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	238,000	240,100	141,500	81,000	157,000	205,600	8,200	32,900	0	0	0	103,700
	Liquid	15,100	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		15,100	14,400	40,000	35,600	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	64,800	65,200	36,600	0	0	0	0	0	0	0
	Truck	0	0	28,200	65,200	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,504,200	2,258,300	2,651,900	2,239,200	1,911,300	1,190,700	1,268,000	916,200	892,300	874,600	851,900	993,200

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Normal Year 2009-10
(MMBtu)

REQUIREMENTS		11/2009	12/2009	01/2010	02/2010	03/2010	04/2010	05/2010	06/2010	07/2010	08/2010	09/2010	10/2010
Firm Sendout		1,537,200	2,309,100	2,657,700	2,200,200	1,943,700	1,162,200	729,200	407,700	350,400	350,600	462,000	1,026,500
Refill	Underground Storage	0	0	0	0	0	69,000	531,300	503,800	531,000	528,900	391,200	0
	LNG	21,700	15,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	13,600	79,800	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,558,900	2,324,500	2,711,300	2,315,600	1,968,700	1,231,200	1,295,500	936,300	906,300	889,700	856,000	1,029,400
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	79,800	164,900	8,800	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	609,800	619,700	554,500	0	0	0	0	0	0	0	0
	Gulf Supply	643,500	643,800	636,000	574,500	636,000	647,900	669,400	648,000	658,800	656,700	637,300	613,800
	Market Area -- Zone 4	429,300	185,400	0	0	63,800	149,200	367,500	37,600	0	0	0	76,300
	Market Area -- Zone 6	3,300	0	0	0	79,100	0	0	0	0	0	0	0
	Storage	9,400	295,600	784,800	678,200	706,700	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	215,100	248,000	147,000	91,600	166,900	217,000	0	10,300	0	0	0	112,300
	Liquid	21,700	15,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		21,700	19,700	35,700	35,600	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	4,000	46,200	79,800	36,600	0	0	0	0	0	0	0
	Truck	0	0	13,600	79,800	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,558,900	2,324,600	2,711,500	2,315,700	1,968,900	1,231,300	1,295,400	936,400	906,300	889,700	856,000	1,029,400

COMPARISON OF RESOURCES AND REQUIREMENTS
High Case Normal Year 2010-11
(MMBtu)

REQUIREMENTS		11/2010	12/2010	01/2011	02/2011	03/2011	04/2011	05/2011	06/2011	07/2011	08/2011	09/2011	10/2011
Firm Sendout		1,590,300	2,381,000	2,739,500	2,268,500	2,007,100	1,206,400	759,500	426,300	366,300	367,500	484,500	1,066,500
Refill	Underground Storage	0	0	0	0	0	88,800	531,300	510,500	525,900	522,700	373,000	0
	LNG	25,000	18,300	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	17,500	27,700	48,300	0	0	22,000	20,700	0	0	0	0
Total Requirements		1,615,300	2,416,800	2,807,200	2,352,400	2,032,100	1,295,200	1,325,800	960,300	895,100	893,100	860,300	1,069,400
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	85,600	198,400	72,100	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	614,500	620,000	549,500	0	0	0	0	0	0	0	0
	Gulf Supply	645,400	669,500	636,000	574,500	636,000	647,900	669,400	647,900	669,500	667,300	641,600	624,900
	Market Area -- Zone 4	463,300	278,900	0	0	68,100	237,400	397,800	73,200	100	0	0	95,100
	Market Area – Zone 6	14,500	0	0	0	147,100	0	0	0	0	0	0	0
	Storage	9,400	221,800	808,700	714,000	717,600	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	217,900	248,000	150,000	99,700	177,300	192,800	0	0	0	0	0	122,200
	Liquid	25,000	18,300	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		25,000	22,200	38,600	33,200	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	17,500	64,300	48,300	6,100	0	0	0	0	0	0	0
	Truck	0	17,500	27,700	48,300	0	0	22,000	20,700	0	0	0	0
Total Resources		1,615,400	2,416,900	2,807,300	2,352,500	2,032,000	1,295,300	1,325,700	960,300	895,100	893,000	860,300	1,069,200

EnergyNorth
Low Case
Resources and Requirements
2006-07 Through 2010-11

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Design Year
(MMBtu)

Heating Season (Nov-Mar)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		10,123,200	10,358,400	10,430,400	10,582,000	10,765,200
Refill	Underground Storage	600	0	0	0	0
	LNG	123,600	125,600	128,600	134,000	139,000
	Propane	93,500	93,500	93,500	93,400	93,500
Total Requirements		10,340,900	10,577,500	10,652,500	10,809,400	10,997,700
RESOURCES						
PNGTS		21,000	21,200	21,000	21,000	21,000
TGP	AES-Londonderry	179,000	238,000	292,200	298,000	355,000
	ANE	584,700	597,200	593,300	593,300	593,300
	BP / Nexen	447,200	450,200	447,200	447,200	447,200
	CoEnergy	1,784,000	1,784,000	1,784,000	1,784,000	1,784,000
	Gulf Supply	3,120,600	3,118,500	3,098,000	3,125,000	3,140,800
	Market Area -- Zone 4	416,800	518,500	552,700	614,900	699,900
	Market Area -- Zone 6	0	0	0	53,300	108,700
	Storage	2,484,400	2,489,600	2,488,400	2,486,800	2,474,300
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	789,200	841,800	851,700	851,200	865,200
	Liquid	123,600	125,600	128,600	134,000	139,000
LNG From Storage		130,800	132,700	135,800	141,200	146,200
Propane	Vapor	166,700	166,700	166,600	166,600	130,100
	Truck	93,500	93,500	93,500	93,400	93,500
Total Resources		10,341,500	10,577,500	10,653,000	10,809,900	10,998,200

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Design Year
(MMBtu)

Non-Heating Season (Apr-Oct)

		2006-07	2007-08	2008-09	2009-10	2010-11
REQUIREMENTS						
Firm Sendout		3,904,200	3,983,100	4,051,700	4,124,400	4,213,500
Refill	Underground Storage	2,564,800	2,570,800	2,569,300	2,567,800	2,554,900
	LNG	27,300	27,300	27,300	27,300	27,300
	Propane	73,300	73,300	73,300	73,300	36,600
Total Requirements		6,569,600	6,654,500	6,721,600	6,792,800	6,832,300
RESOURCES						
PNGTS		12,600	12,600	12,600	12,600	12,600
TGP	AES-Londonderry	0	0	0	0	0
	ANE	840,900	840,900	840,900	840,900	840,900
	BP / Nexen	668,300	668,300	668,300	668,300	668,300
	CoEnergy	0	0	0	0	0
	Gulf Supply	3,840,600	4,297,400	4,330,300	4,351,100	4,379,700
	Market Area -- Zone 4	667,700	348,700	392,400	442,300	504,000
	Market Area -- Zone 6	0	0	0	0	0
	Storage	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	418,900	366,100	356,300	356,800	342,900
	Liquid	27,300	27,300	27,300	27,300	27,300
LNG From Storage		20,000	20,000	20,000	20,000	20,000
Propane	Vapor	0	0	0	0	0
	Truck	73,300	73,300	73,300	73,300	36,600
Total Resources		6,569,600	6,654,600	6,721,400	6,792,600	6,832,300

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Design Year
(MMBtu)

Peak Day

		2006-07	2007-08	2008-09	2009-10	2010-11
REQUIREMENTS						
Firm Sendout		134,100	136,200	138,000	139,900	142,300
Refill	Underground Storage	0	0	0	0	0
	LNG	2,000	2,000	2,000	2,000	2,000
	Propane	0	2,390	0	0	0
Total Requirements		136,100	140,590	140,000	141,900	144,300
RESOURCES						
PNGTS		160	160	160	160	160
TGP	AES-Londonderry	15,000	15,000	15,000	15,000	15,000
	ANE	3,970	3,970	3,970	3,970	3,970
	BP / Nexen	3,120	3,120	3,120	3,120	3,120
	CoEnergy	20,000	20,000	20,000	20,000	20,000
	Gulf Supply	21,600	21,600	21,600	21,600	21,600
	Market Area -- Zone 4	0	0	0	0	0
	Market Area -- Zone 6	0	0	0	0	0
	Storage	28,110	28,110	28,110	28,110	28,110
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	8,000	8,000	8,000	8,000	8,000
	Liquid	2,000	2,000	2,000	2,000	2,000
LNG From Storage		2,000	1,310	3,140	5,060	7,380
Propane	Vapor	32,240	35,000	35,000	35,000	35,000
	Truck	0	2,390	0	0	0
Total Resources		136,200	140,660	140,100	142,020	144,340

Chart IV-D-34

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Design Year 2006-07
(MMBtu)

REQUIREMENTS		11/2006	12/2006	01/2007	02/2007	03/2007	04/2007	05/2007	06/2007	07/2007	08/2007	09/2007	10/2007
Firm Sendout		1,425,400	2,195,800	2,564,900	2,134,900	1,802,200	1,062,700	614,400	362,300	277,800	274,800	386,300	925,900
Refill	Underground Storage	600	0	0	0	0	465,100	531,300	514,300	531,300	515,100	7,700	0
	LNG	8,600	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	24,500	69,000	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,434,600	2,210,200	2,629,400	2,239,500	1,827,200	1,527,800	1,180,700	901,400	834,000	800,100	396,800	928,800
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	64,000	99,300	0	15,700	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	101,400	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	608,900	615,100	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	638,100	636,000	636,000	574,500	636,000	647,800	669,000	616,000	586,400	567,100	178,200	576,100
	Market Area – Zone 4	360,400	14,500	0	0	41,900	434,800	193,500	2,400	0	0	0	37,000
	Market Area – Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	600	412,700	751,200	648,000	671,900	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	203,600	222,300	138,800	79,200	145,300	228,000	59,700	42,500	0	0	0	88,700
	Liquid	8,600	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		8,600	14,400	40,000	35,600	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	61,100	69,000	36,600	0	0	0	0	0	0	0
	Truck	0	0	24,500	69,000	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,434,800	2,210,300	2,629,600	2,239,600	1,827,200	1,527,800	1,180,700	901,400	833,900	800,100	396,900	928,800

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Design Year 2007-08
(MMBtu)

REQUIREMENTS		11/2007	12/2007	01/2008	02/2008	03/2008	04/2008	05/2008	06/2008	07/2008	08/2008	09/2008	10/2008
Firm Sendout		1,450,600	2,230,600	2,605,000	2,239,600	1,832,600	1,083,000	627,500	369,200	283,200	280,800	395,400	944,000
Refill	Underground Storage	0	0	0	0	0	45,500	531,300	514,300	531,300	517,200	431,200	0
	LNG	10,500	14,400	40,000	35,700	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	17,600	75,900	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,461,100	2,245,000	2,662,600	2,351,200	1,857,600	1,128,500	1,193,800	908,300	839,400	808,200	829,400	946,900
RESOURCES													
PNGTS		3,300	4,600	5,100	4,100	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	70,200	133,400	5,600	28,800	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	113,900	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	66,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	603,900	606,400	573,700	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	595,000	636,000	647,800	669,200	619,100	591,900	575,200	610,700	583,500
	Market Area -- Zone 4	373,400	97,200	0	0	47,900	98,200	203,100	3,100	0	0	0	44,300
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	7,500	344,600	772,800	684,200	680,500	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	228,900	238,000	141,800	85,100	148,000	165,400	63,000	45,700	0	0	0	92,000
	Liquid	10,500	14,400	40,000	35,700	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		10,500	17,400	36,900	35,700	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	54,200	75,900	36,600	0	0	0	0	0	0	0
	Truck	0	0	17,600	75,900	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,461,200	2,244,800	2,662,700	2,351,200	1,857,600	1,128,600	1,193,800	908,400	839,400	808,200	829,400	946,800

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Design Year 2008-09
(MMBtu)

		11/2008	12/2008	01/2009	02/2009	03/2009	04/2009	05/2009	06/2009	07/2009	08/2009	09/2009	10/2009
REQUIREMENTS													
Firm Sendout		1,472,600	2,261,100	2,640,300	2,197,200	1,859,200	1,100,800	638,900	375,200	287,900	285,900	403,200	959,800
Refill	Underground Storage	0	0	0	0	0	48,200	531,300	503,100	531,300	526,900	428,500	0
	LNG	13,600	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	3,000	25,400	65,100	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,486,200	2,278,500	2,705,700	2,297,900	1,884,200	1,149,000	1,205,200	903,100	844,100	823,000	834,500	962,700
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	74,100	149,200	28,200	40,700	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	615,100	620,000	548,900	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	574,500	636,000	647,800	669,300	621,700	596,500	590,000	615,900	589,100
	Market Area -- Zone 4	387,800	109,200	0	0	55,700	110,500	228,500	2,400	0	0	0	51,000
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	9,400	347,000	769,600	678,400	684,000	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	231,500	234,800	144,400	89,500	151,500	173,500	48,800	38,500	0	0	0	95,500
	Liquid	13,600	14,400	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		13,600	18,700	35,700	35,600	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	3,000	61,900	65,100	36,600	0	0	0	0	0	0	0
	Truck	0	3,000	25,400	65,100	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,486,300	2,278,400	2,705,800	2,298,200	1,884,300	1,149,000	1,205,100	903,100	844,000	823,000	834,600	962,600

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Design Year 2009-10
(MMBtu)

REQUIREMENTS		11/2009	12/2009	01/2010	02/2010	03/2010	04/2010	05/2010	06/2010	07/2010	08/2010	09/2010	10/2010
Firm Sendout		1,495,800	2,293,300	2,677,500	2,228,000	1,887,400	1,119,700	650,900	381,500	292,800	291,400	411,600	976,500
Refill	Underground Storage	0	0	0	0	0	52,900	531,300	502,700	531,300	526,700	422,900	0
	LNG	17,900	15,500	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	7,500	33,500	52,400	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,513,700	2,316,300	2,751,000	2,316,000	1,912,400	1,172,600	1,217,200	909,000	849,000	828,300	837,300	979,400
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	78,100	165,400	54,500	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	64,800	95,300	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	604,000	620,000	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	641,100	637,400	636,000	574,500	636,000	647,800	669,400	624,100	601,500	595,200	618,600	594,500
	Market Area -- Zone 4	404,000	153,900	0	0	57,000	123,500	257,300	2,900	0	0	0	58,600
	Market Area -- Zone 6	0	0	0	0	53,300	0	0	0	0	0	0	0
	Storage	9,400	321,400	780,600	679,400	696,000	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	208,700	248,000	146,300	93,000	155,200	184,100	31,900	41,500	0	0	0	99,300
	Liquid	17,900	15,500	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		17,900	19,800	35,700	35,600	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	7,500	70,100	52,400	36,600	0	0	0	0	0	0	0
	Truck	0	7,500	33,500	52,400	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,513,900	2,316,200	2,751,200	2,316,100	1,912,500	1,172,600	1,217,100	909,000	849,000	828,200	837,300	979,400

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Design Year 2010-11
(MMBtu)

REQUIREMENTS		11/2010	12/2010	01/2011	02/2011	03/2011	04/2011	05/2011	06/2011	07/2011	08/2011	09/2011	10/2011
Firm Sendout		1,524,000	2,332,200	2,722,400	2,265,200	1,921,400	1,142,500	665,700	389,400	299,100	298,200	421,800	996,800
Refill	Underground Storage	0	0	0	0	0	44,700	531,300	502,200	531,300	529,900	415,500	0
	LNG	21,400	17,000	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	13,000	43,400	37,100	0	0	22,000	14,600	0	0	0	0
Total Requirements		1,545,400	2,362,200	2,805,800	2,337,900	1,946,400	1,187,200	1,232,000	909,000	833,300	831,000	840,100	999,700
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	82,600	185,300	87,100	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	110,000	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	609,800	619,700	554,500	0	0	0	0	0	0	0	0
	Gulf Supply	642,000	652,300	636,000	574,500	636,000	647,900	669,400	627,200	607,700	605,200	621,500	600,800
	Market Area -- Zone 4	422,700	214,800	0	0	62,400	140,900	291,000	3,900	0	0	0	68,200
	Market Area -- Zone 6	2,600	0	0	0	106,100	0	0	0	0	0	0	0
	Storage	9,400	267,000	794,200	702,200	701,500	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	211,100	248,000	147,700	97,900	160,500	181,300	13,000	44,900	0	0	0	103,700
	Liquid	21,400	17,000	40,000	35,600	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		21,400	21,700	36,100	34,800	32,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	13,000	80,000	37,100	0	0	0	0	0	0	0	0
	Truck	0	13,000	43,400	37,100	0	0	22,000	14,600	0	0	0	0
Total Resources		1,545,500	2,362,300	2,806,000	2,338,100	1,946,300	1,187,300	1,231,900	909,100	833,200	830,900	840,200	999,700

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Normal Year
(MMBtu)

Heating Season (Nov-Mar)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		9,179,000	9,394,000	9,465,300	9,606,700	9,777,500
Refill	Underground Storage	0	0	0	0	0
	LNG	42,200	36,400	68,400	107,400	119,100
	Propane	93,500	93,400	93,500	93,400	93,500
Total Requirements		9,314,700	9,523,800	9,627,200	9,807,500	9,990,100
RESOURCES						
PNGTS		21,000	21,200	21,000	21,000	21,000
TGP	AES-Londonderry	0	0	0	0	28,000
	ANE	584,700	588,600	584,700	584,700	584,700
	BP / Nexen	447,200	450,200	447,200	447,100	447,200
	CoEnergy	1,783,900	1,784,000	1,784,000	1,783,900	1,784,000
	Gulf Supply	3,098,000	3,118,500	3,098,000	3,098,000	3,098,000
	Market Area -- Zone 4	279,900	209,000	250,100	332,800	369,500
	Market Area -- Zone 6	0	0	0	0	45,300
	Storage	2,309,000	2,490,000	2,490,400	2,488,800	2,490,900
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	478,200	522,700	547,900	571,400	652,900
	Liquid	42,200	36,400	68,400	107,400	119,100
LNG From Storage		49,400	43,600	75,500	114,600	126,300
Propane	Vapor	128,000	166,600	166,700	164,500	130,100
	Truck	93,500	93,400	93,500	93,400	93,500
Total Resources		9,315,000	9,524,200	9,627,400	9,807,600	9,990,500

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Normal Year
(MMBtu)

Non-Heating Season (Apr-Oct)

REQUIREMENTS		2006-07	2007-08	2008-09	2009-10	2010-11
Firm Sendout		3,659,300	3,734,700	3,800,500	3,870,000	3,955,500
Refill	Underground Storage	2,383,200	2,571,200	2,571,900	2,569,900	2,572,300
	LNG	27,300	27,300	27,300	27,300	27,300
	Propane	34,500	73,300	73,300	71,200	36,600
Total Requirements		6,104,300	6,406,500	6,473,000	6,538,400	6,591,700
RESOURCES						
PNGTS		12,600	12,600	12,600	12,600	12,600
TGP	AES-Londonderry	0	0	0	0	0
	ANE	840,900	840,900	840,900	840,900	840,900
	BP / Nexen	668,300	668,300	668,300	668,300	668,300
	CoEnergy	0	0	0	0	0
	Gulf Supply	3,520,700	3,949,000	4,021,800	4,092,100	4,233,200
	Market Area -- Zone 4	250,100	129,800	148,600	169,400	197,600
	Market Area -- Zone 6	0	0	0	0	0
	Storage	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0
DOMAC	Vapor	729,700	685,400	660,100	636,500	555,100
	Liquid	27,300	27,300	27,300	27,300	27,300
LNG From Storage		20,000	20,000	20,000	20,000	20,000
Propane	Vapor	0	0	0	0	0
	Truck	34,500	73,300	73,300	71,200	36,600
Total Resources		6,104,100	6,406,600	6,472,900	6,538,300	6,591,600

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Normal Year 2006-07
(MMBtu)

REQUIREMENTS		11/2006	12/2006	01/2007	02/2007	03/2007	04/2007	05/2007	06/2007	07/2007	08/2007	09/2007	10/2007
Firm Sendout		1,306,000	1,997,200	2,303,400	1,903,900	1,668,500	969,200	596,100	325,100	279,300	275,200	362,300	852,100
Refill	Underground Storage	0	0	0	0	0	296,200	531,300	514,300	531,300	502,400	7,700	0
	LNG	2,800	14,400	0	0	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	11,000	66,500	16,000	0	0	22,000	12,500	0	0	0	0
Total Requirements		1,308,800	2,022,600	2,369,900	1,919,900	1,693,500	1,265,400	1,162,400	854,700	813,500	780,500	372,800	855,000
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	0	0	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	101,400	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	612,900	618,800	552,200	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	574,500	636,000	647,800	669,000	611,700	587,900	554,800	84,800	364,700
	Market Area -- Zone 4	266,600	0	0	0	13,300	170,900	64,000	0	0	0	0	15,200
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	0	455,900	664,400	527,200	661,500	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	206,300	43,000	88,000	46,600	94,300	229,500	170,900	12,000	0	0	69,300	248,000
	Liquid	2,800	14,400	0	0	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		2,800	15,300	6,100	3,000	22,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	11,000	66,500	31,900	18,600	0	0	0	0	0	0	0
	Truck	0	11,000	66,500	16,000	0	0	22,000	12,500	0	0	0	0
Total Resources		1,308,900	2,022,600	2,369,900	1,920,100	1,693,500	1,265,400	1,162,400	854,700	813,400	780,500	372,800	854,900

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Normal Year 2007-08
(MMBtu)

REQUIREMENTS		11/2007	12/2007	01/2008	02/2008	03/2008	04/2008	05/2008	06/2008	07/2008	08/2008	09/2008	10/2008
Firm Sendout		1,329,500	2,029,600	2,340,600	1,997,400	1,696,900	988,400	608,500	331,900	284,700	281,100	371,000	869,100
Refill	Underground Storage	0	0	0	0	0	145,700	531,300	514,300	531,300	512,900	335,700	0
	LNG	3,000	14,400	4,600	0	14,400	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	56,000	37,400	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,332,500	2,044,000	2,401,200	2,034,800	1,711,300	1,134,100	1,174,800	871,000	840,900	804,200	709,500	872,000
RESOURCES													
PNGTS		3,300	4,600	5,100	4,100	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	0	0	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	105,300	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	66,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	610,500	618,500	555,000	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	595,000	636,000	647,800	669,100	615,700	593,400	571,200	473,900	377,900
	Market Area -- Zone 4	175,500	0	0	0	33,500	38,900	71,900	0	0	0	0	19,000
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	109,800	482,100	680,000	579,800	638,300	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	211,000	44,600	98,000	50,700	118,400	230,300	175,200	14,900	0	0	17,000	248,000
	Liquid	3,000	14,400	4,600	0	14,400	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		3,000	21,700	3,700	3,700	11,500	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	11,600	81,000	37,400	36,600	0	0	0	0	0	0	0
	Truck	0	0	56,000	37,400	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,332,700	2,044,000	2,401,400	2,034,800	1,711,300	1,134,200	1,174,700	871,100	840,900	804,200	709,600	871,900

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Normal Year 2008-09
(MMBtu)

REQUIREMENTS		11/2008	12/2008	01/2009	02/2009	03/2009	04/2009	05/2009	06/2009	07/2009	08/2009	09/2009	10/2009
Firm Sendout		1,350,100	2,058,100	2,373,300	1,962,100	1,721,700	1,005,200	619,300	337,800	289,400	286,200	378,600	884,000
Refill	Underground Storage	0	0	0	0	0	137,500	531,300	514,300	531,300	513,000	344,500	0
	LNG	4,000	14,400	28,300	0	21,700	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	19,400	67,900	6,200	0	0	22,000	22,000	22,000	7,300	0	0
Total Requirements		1,354,100	2,091,900	2,469,500	1,968,300	1,743,400	1,142,700	1,185,600	876,900	845,600	809,400	725,900	886,900
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	0	0	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	101,400	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	618,800	620,000	545,200	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	574,500	636,000	647,900	669,300	618,500	598,000	576,400	507,200	404,500
	Market Area -- Zone 4	213,700	0	0	0	36,400	46,800	79,100	0	0	0	0	22,700
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	87,300	494,700	690,900	572,000	645,500	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	214,800	45,800	107,400	54,100	125,800	230,900	178,600	17,900	0	0	0	232,700
	Liquid	4,000	14,400	28,300	0	21,700	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		4,000	20,300	27,500	4,800	18,900	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	19,400	67,900	42,800	36,600	0	0	0	0	0	0	0
	Truck	0	19,400	67,900	6,200	0	0	22,000	22,000	22,000	7,300	0	0
Total Resources		1,354,200	2,091,900	2,469,500	1,968,300	1,743,500	1,142,800	1,185,500	876,900	845,500	809,400	725,900	886,900

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Normal Year 2009-10
(MMBtu)

REQUIREMENTS		11/2009	12/2009	01/2010	02/2010	03/2010	04/2010	05/2010	06/2010	07/2010	08/2010	09/2010	10/2010
Firm Sendout		1,371,800	2,088,200	2,407,900	1,990,800	1,748,000	1,023,000	630,700	344,000	294,300	291,600	386,600	899,800
Refill	Underground Storage	0	0	0	0	0	129,600	531,300	514,300	531,300	513,500	349,900	0
	LNG	5,100	14,400	35,500	27,400	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	28,300	62,600	0	2,500	0	22,000	22,000	22,000	5,200	0	0
Total Requirements		1,376,900	2,130,900	2,506,000	2,018,200	1,775,500	1,152,600	1,197,000	883,100	850,500	813,200	739,300	902,700
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	0	0	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	101,400	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	66,000	94,000	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	613,800	610,100	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	574,500	636,000	647,800	669,400	621,500	603,000	582,300	520,700	447,400
	Market Area -- Zone 4	297,800	0	0	0	35,000	56,100	86,700	0	0	0	0	26,600
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	20,000	520,900	713,300	572,000	662,600	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	218,600	47,900	116,500	58,200	130,200	231,500	182,300	21,100	0	0	0	201,600
	Liquid	5,100	14,400	35,500	27,400	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		5,100	18,200	36,500	27,600	27,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	28,300	71,900	27,300	37,000	0	0	0	0	0	0	0
	Truck	0	28,300	62,600	0	2,500	0	22,000	22,000	22,000	5,200	0	0
Total Resources		1,377,000	2,130,900	2,506,000	2,018,300	1,775,400	1,152,600	1,196,900	883,100	850,500	813,200	739,400	902,600

COMPARISON OF RESOURCES AND REQUIREMENTS
Low Case Normal Year 2010-11
(MMBtu)

REQUIREMENTS		11/2010	12/2010	01/2011	02/2011	03/2011	04/2011	05/2011	06/2011	07/2011	08/2011	09/2011	10/2011
Firm Sendout		1,398,200	2,124,600	2,449,500	2,025,400	1,779,800	1,044,600	644,700	351,800	300,600	298,400	396,500	918,900
Refill	Underground Storage	0	0	0	0	0	121,700	531,300	514,300	531,300	515,700	358,000	0
	LNG	6,400	14,400	38,900	34,400	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	7,100	53,900	32,500	0	0	22,000	14,600	0	0	0	0
Total Requirements		1,404,600	2,146,100	2,542,300	2,092,300	1,804,800	1,166,300	1,211,000	883,500	834,800	817,000	757,300	921,800
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	28,000	0	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	101,400	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	606,500	617,500	560,000	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	574,500	636,000	647,900	669,400	625,100	609,200	591,300	538,700	551,600
	Market Area – Zone 4	329,000	0	0	0	40,500	68,800	96,300	0	0	0	0	32,500
	Market Area – Zone 6	0	0	0	0	45,300	0	0	0	0	0	0	0
	Storage	9,400	500,500	719,600	594,500	666,900	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	223,100	103,400	126,200	62,700	137,500	232,400	186,700	25,300	0	0	0	110,700
	Liquid	6,400	14,400	38,900	34,400	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		6,400	20,100	36,200	32,600	31,000	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	7,100	90,500	32,500	0	0	0	0	0	0	0	0
	Truck	0	7,100	53,900	32,500	0	0	22,000	14,600	0	0	0	0
Total Resources		1,404,700	2,146,200	2,542,400	2,092,400	1,804,800	1,166,300	1,210,900	883,500	834,700	817,000	757,400	921,800

EnergyNorth
Cold Snap Scenario
Resources and Requirements
2006-07

COMPARISON OF RESOURCES AND REQUIREMENTS
Cold Snap Scenario 2006-07
(MMBtu)

		11/2006	12/2006	01/2007	02/2007	03/2007	04/2007	05/2007	06/2007	07/2007	08/2007	09/2007	10/2007
REQUIREMENTS													
Firm Sendout		1,347,600	2,052,800	2,431,500	1,956,700	1,717,800	1,004,100	620,600	340,800	293,000	289,700	381,000	883,800
Refill	Underground Storage	600	0	0	0	0	389,800	531,300	514,300	530,800	502,400	7,700	0
	LNG	3,800	14,400	34,200	17,200	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
	Propane	0	0	93,500	0	0	0	22,000	22,000	22,000	2,400	0	0
Total Requirements		1,352,000	2,067,200	2,559,200	1,973,900	1,742,800	1,393,900	1,186,900	879,900	848,700	797,400	391,500	886,700
RESOURCES													
PNGTS		3,300	4,600	5,100	3,900	4,100	2,800	2,000	1,300	1,100	1,300	1,500	2,600
TGP	AES-Londonderry	0	20,000	29,100	0	0	0	0	0	0	0	0	0
	ANE	117,900	121,800	121,800	101,400	121,800	117,900	121,800	117,900	121,800	121,800	117,900	121,800
	BP / Nexen	93,700	96,700	96,700	63,400	96,700	93,700	96,800	93,700	96,800	96,800	93,700	96,800
	CoEnergy	0	609,200	619,800	555,000	0	0	0	0	0	0	0	0
	Gulf Supply	615,500	636,000	636,000	574,500	636,000	647,900	669,400	620,800	601,200	569,300	172,800	392,200
	Market Area -- Zone 4	298,000	0	0	0	29,400	297,700	79,100	0	0	0	0	22,200
	Market Area -- Zone 6	0	0	0	0	0	0	0	0	0	0	0	0
	Storage	600	500,700	682,100	559,300	656,500	0	0	0	0	0	0	0
Other Purchased Resources		0	0	0	0	0	0	0	0	0	0	0	0
DOMAC	Vapor	215,500	45,500	99,200	53,400	119,400	231,200	179,800	18,700	0	0	0	245,200
	Liquid	3,800	14,400	34,200	17,200	25,000	0	13,000	2,800	2,900	2,900	2,800	2,900
LNG From Storage		3,800	18,200	33,600	24,100	22,200	2,800	2,900	2,800	2,900	2,900	2,800	2,900
Propane	Vapor	0	0	108,200	21,900	31,700	0	0	0	0	0	0	0
	Truck	0	0	93,500	0	0	0	22,000	22,000	22,000	2,400	0	0
Total Resources		1,352,100	2,067,100	2,559,300	1,974,100	1,742,800	1,394,000	1,186,800	880,000	848,700	797,400	391,500	886,600

V. MANAGEMENT OF THE RESOURCE PORTFOLIO

A. Introduction

The Company's resource management effort is a continuous process used by the Company to manage its portfolio in order to: (i) maximize the use of capacity, (ii) minimize the cost of gas, (iii) maintain flexibility to meet changing weather conditions and uncertainties of the competitive demand and supply markets, and (iv) maintain operational integrity of its distribution system. Because the Company must maintain sufficient capacity in its resource portfolio to meet current and expected design day and design year customer requirements, at any given time, it might have resources that are temporarily under-utilized. Through its resource management efforts, the Company seeks to extract the maximum value possible from these under-utilized resources and maintain the lowest cost for its firm customers.

B. Portfolio Management

As part of the Settlement, the Company agreed not to renew its Gas Resource Portfolio Management and Gas Sales Agreement ("Portfolio Management Agreement") with Merrill Lynch Commodities, LLC ("Merrill") that terminated on March 31, 2006. On December 8, 2005, the Company filed its Portfolio Management Plan with the Commission which provided a detailed plan on how the Company would manage its gas resources effective with the termination of its Portfolio Management Agreement with Merrill. The Portfolio Management Plan is provided as Appendix B.

C. Benefits of a Coordinated KeySpan New England Portfolio

There are a number of benefits enjoyed by New Hampshire customers as a result of the coordination of the gas supply planning and acquisition efforts with those of the three KeySpan LDCs in Massachusetts. This coordination has created the opportunity for the Company's customers to benefit from the economies of scale and scope that were not available when the Company performed these functions on its own.

For example, shortly after the KeySpan merger, EnergyNorth coordinated its contract-renewal negotiations with its primary pipeline supplier, Tennessee, with those of the KeySpan Massachusetts LDCs. This greatly increased the Company's bargaining power[1]. One significant benefit resulting from the negotiations was the creation of a single Operational Balancing Agreement ("OBA") with Tennessee for all of the KeySpan New England citygates. This allows the Company and the KeySpan Massachusetts LDCs to balance deliveries across all of its Tennessee citygates in New England.

A second example of the benefits of coordinated portfolios is that of displacement. Displacement combines the benefits of both the single OBA and

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[1] During those negotiations, Tennessee agreed to contribute to a significant distribution system upgrade to serve additional load in the Tilton, NH area to the benefit of both the Company and Tennessee.

the use of on-system supply and distribution assets between the Company and the KeySpan Massachusetts LDCs. On any given day, the Massachusetts LDCs may make LNG available to EnergyNorth by vaporizing LNG into their systems and "deliver" it to EnergyNorth through displacement on its distribution system and the Tennessee pipeline. Because KeySpan has a single OBA for New England, EnergyNorth incurs only the commodity cost and the LNG trucking costs to the MA facility and avoids the pipeline transportation costs to which it otherwise would have been subject.

A third example of the benefits to the Company from coordination with the KeySpan Massachusetts LDCs is its ability to use a 500,000 gallon propane storage tank in Haverhill, Massachusetts to the extent that is not currently needed to meet sendout requirements in the Massachusetts portfolio. Because of the close proximity of the Haverhill facility to the EnergyNorth service territory, this facility has been made available for propane storage needed to meet peak season sendout requirements for New Hampshire customers. Without this facility, EnergyNorth would be required to contract for an incremental winter refill contract.

A fourth example of the benefits to the Company from coordination with the KeySpan Massachusetts LDCs relates to LNG winter trucking. Each winter season, the Company contracts with Transgas Inc. for a "Dedicated Service" agreement for the months of December, January and February. The agreement provides for a specific level of service including both trailers and drivers for trucking LNG. Each LDC pays a portion of the cost based on its need on the design day for a portable vaporizer(s) if any, and its design winter season sendout percentage of the total of the total design winter season. Given design conditions, each LDC would be limited to the level of service it pays for. However, in the absence of design conditions, if the resources paid for by one LDC are not being fully utilized on any given day, any of the other LDCs may call upon those temporarily unutilized resources and pay only the variable charges incurred for using those resources. Without this flexibility, each individual LDC would need to contract for incremental trucking service.

D. Storage Management

Within the overall management of its portfolio, the Company must also adhere to two specific rules as established by the Commission related to the management of storage supplies; (1) Storage Rule Curve and (2) Seven Day Storage Rule.

1) Storage Rule Curve

Since the 2004/05 winter period, the Company has implemented a strategy that it agreed upon with Commission Staff regarding the dispatch of underground storage volumes. Under this strategy, during the peak period, the Company computes the cumulative forecasted usage under its design weather scenario of total underground storage volumes for the remainder of the peak period as of the end of each month as listed in Schedule 11B of the September 1st Cost of Gas filing. The Company divides these cumulative volumes by its total underground storage MSQ and these values ("rule curve") are used by the Company to determine the minimum overall end-of month inventory level for its underground storage fields. Within each month, the Company may withdraw underground storage volumes to levels below the rule curve on any given day, so long as by the last day of each month the Company is at or above the rule curve.[2]

2) Seven Day Storage Rule

Puc rule 506.03 ("On-site Storage") directs New Hampshire gas utilities to "maintain an on-site storage capability in connection with the operation of its gas distribution system between December 1 and February 14 of each year which will provide peak shaving supplies for an estimated maximum-design cold period of 7 consecutive days." Under the rule, between February 15 and February 28, the minimum on-site storage capacity may then be reduced to 75% of the total requirement and between March 1 and March 31 the minimum on-site storage requirement may then be reduced to 50% of the original total requirement.

E. Managing Volatility

The natural gas commodity market continues to be volatile. Spiking price increases in the spring and summer of 2005 were exacerbated by the effects of Hurricanes Katrina and Rita, which shut down both offshore gas platforms and onshore gas processing plants, causing gas prices to rise from the $7-$8/MMBtu

[2] The sole criterion for reviewing the prudence of the Company's dispatch of underground storage volumes is the Company's ability to remain at or above this rule curve as of the last day of each month within the peak period.

range into the $14-$15/MMBtu range in late September 2005. Since then, prices have moderated as demand slackened from a combination of conservation and a relatively mild winter and higher levels of storage inventories nationally. At the time of this filing, prices for the upcoming 2006/07 winter remain in the $9-$10 range, somewhat below the $14 - $15/MMBu range of last year.

The Company mitigates volatility in the gas commodity markets in several ways. First, the Company maintains a balanced portfolio that includes contract storage and on-system LNG. These assets allow the Company to inject gas during the off peak season for withdrawal during the peak season, providing a natural pricing hedge. Second, the Company maintains a geographically diverse gas supply portfolio that reduces its exposure to volatility in any single supply region and also minimizes exposure to volatility at a single pricing point or market index. Finally, the Company mitigates price volatility with a formal hedging program, its Natural Gas Risk Management Plan, as well as its Fixed Price Option program.

Under the Natural Gas Risk Management Plan the Company uses two hedging strategies aimed at reducing gas cost volatility or fixing the cost of gas. Under one strategy, financial derivatives are executed before the winter heating season to establish a price or price range for 50% of the estimated flowing volume for each month from October through May. Under the other strategy, financial derivatives are executed prior to the summer injection season to establish a price or price range for 20% of the market area storage capacity. The total volume hedged, based on the storage capacity forecast, is divided equally over the May through October injection period. Lastly, the Company offers a Fixed Price Option ("FPO") program to its customers whereby customers are given the option to fix the price for the gas supply portion of their bills for the winter season. In order to fix the cost of gas supplies for this program, the Company hedges 35% of its portfolio. The Company received Commission approval on September 16, 2005, Order No. 24,515 in Docket No. DG 05-127, for both its Natural Gas Risk Management Plan and Fixed Price Option program.

VI. SUMMARY OF COMPLIANCE WITH THE TERMS OF THE AUGUST 19, 2005 SETTLEMENT

On August 19, 2005, the Company, the Commission Staff and the Office of the Consumer Advocate entered into a Settlement to resolve outstanding issue in dockets DG 04-133 and DG 04-175 which was approved by the Commission in Order No. 24,531 dated October 12, 2005. The Settlement requires the Company to incorporate certain information into this IRP filing. This section identifies the information to be included and documents the Company's compliance with the Settlement terms.

1. All volumes will be stated in MMBtus;

Throughout the filing, all volume references are stated in MMBtu.

2. For purposes of forecasting average use per customer, the Company will use at least three years' worth of customer usage data;

As documented in Section III Table III-1, the forecast of average use per customer was developed using quarterly data for the twenty- one year period January 1984 through December 2005.

3. The Company will develop an econometric demand forecasting model for use in the IRP in place of the end use forecasting model it currently uses;

The econometric demand forecasting model specified by the Company for this IRP is described in detail in Section III B.

4. For purposes of establishing design planning standards, the Company will utilize a Monte Carlo weather forecasting analysis;

The Monte Carlo weather forecasting analysis used by the Company to develop its design planning standards is described in detail in Section III E.

5. The IRP will include a detailed contingency plan addressing the Company's plans for ensuring adequate supplies and capacity resources for low probability weather scenarios and a range of possible supply/capacity interruptions. Among other things, the contingency plan shall address the following:

(a) Displacement of gas from the Company's Massachusetts affiliates to New Hampshire to the extent feasible under the combined OBA on the Tennessee Gas Pipeline Company system;

(b) The potential for and related cost if the Company were to increase the level of dedicated trucking to deliver liquid supplies to New Hampshire during periods when vaporized LNG from its Massachusetts affiliates' facilities cannot be

displaced via pipeline from Massachusetts to New Hampshire;

(c) A reasonable range of potential supply or capacity disruptions under design day weather conditions and the Company's response to each specified situation, including a loss of pipeline and LNG or propane supplies;

The Company's contingency plan is set forth in Section IV F.

6. The IRP will include a section setting forth the Company's planning practices relating to longer-term portfolio optimization. The section will identify the available and potentially available supply resources and their respective costs. In addition, the section will discuss the opportunities for utilizing these available resources, either as replacements for expiring contracts or meeting load growth, describe the portfolio optimization model, and identify the mix and timing of resource additions and subtractions that are expected to minimize costs over the long-term under a given set of price and demand forecasts. Determination of the optimal portfolio also requires the Company to address the role of its peaking plants in its overall portfolio. Finally, the section will also

identify supply resources that are unlikely to be available to the Company because of its particular circumstances;

The design of the Company's portfolio and the optimization of that portfolio to meet sendout requirements over the forecast period is discussed in Section IV.

7. The IRP will include a section that discusses the extent to which the Company's supply or capacity plans take into account the potential migration of sales service customers to transportation service. In addition, the section will discuss whether and how the Company's plans address the risk that transportation customers migrate to sales service. To the extent that the Company does not plan to serve the gas requirements of all transportation customers, the section will also address how the Company protects customers against a possible reduction in supply reliability resulting from unauthorized gas usage by migrating transportation customers.

A discussion of the Company's historical experience and forecast of transportation migration, including a discussion of planning for "grandfathered transportation load" is contained in Section III B (6).

8. The IRP will include a section that describes the Company's strategy for managing the short, medium and long term risks arising from volatility in gas commodity costs, such as the potential for entering into fixed price forward contracts and financial hedges or the economic operation of peaking facilities.

A discussion of the Company's price volatility management and fixed price option programs is contained in Section V.

9. The IRP will include a section discussing the purpose of the Company's curtailment plan and the implications of that plan for supply and/or capacity planning.

The Company filed its New Hampshire Emergency Curtailment plan with the Commission on November 1, 2005. That plan is not designed to address the Company's upstream capacity and supply planning process or the Company's gas supply contingency planning activities. However, as discussed in Section V, in the event that the company is unable to overcome an upstream force majuere event that prevented it from delivering sufficient supply to meet its firm sendout requirements, the Company would look to the curtailment plan for the most orderly and efficient means of curtailing customer load until such time as the emergency event was resolved.

ENERGYNORTH NATURAL GAS, INC.

(d/b/a KeySpan Energy Delivery New England)

INTEGRATED RESOURCE PLAN

(November 1, 2006 – October 31, 2011)

DG 06-105

APPENDIX A

KEYSPAN
Energy Delivery

APPENDIX A

KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Number of Commercial and Industrial Customers Forecasting

Regression Model:	D1		
Dependent Variable:	CUSCI		
Independent Variable:	CUSCI_1	POP	Auto(-4)

Size	85	Parameters	3
Mean	7462.374	Std Dev	1741.739
R-Square	0.9994	DW	2.3058
SSE	3017373	MSE	35499

Term	CUSCI_1	POP	Auto(-4)
Estimate	0.9309	0.5111	-0.621
Std Error	0.0378	0.25	0.0917
T-Ratio	24.66	2.04	-6.77
Pr>[t]	<.0001	0.044	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	9999.551	10369.02	10738.49
2006Q2	10092.65	10466.01	10839.38
2006Q3	10406.78	10784.19	11161.6
2006Q4	10177.34	10559.87	10942.41
2007Q1	10234.57	10620.96	11007.36
2007Q2	10313.82	10704.07	11094.33
2007Q3	10521.86	10916.05	11310.25
2007Q4	10389.58	10788.31	11187.03
2008Q1	10440.19	10842.68	11245.16
2008Q2	10488.4	10894.61	11300.82
2008Q3	10624.57	11034.48	11444.39
2008Q4	10571.63	10985.53	11399.43
2009Q1	10635.41	11052.89	11470.36
2009Q2	10685.06	11106.14	11527.21
2009Q3	10807.77	11232.42	11657.08
2009Q4	10788.34	11216.82	11645.29
2010Q1	10810.6	11242.61	11674.63
2010Q2	10863.02	11298.47	11733.92
2010Q3	10928.81	11367.68	11806.56
2010Q4	10922.47	11364.8	11807.14
2011Q1	10975.09	11417.43	11866.29
2011Q2	11022.87	11463	11920.59
2011Q3	11076.43	11545.11	11980.63
2011Q4	11120.21	11544.04	12030.91

APPENDIX A

KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Number of Commercial and Industrial Customers Forecasting

Regression Model: D2
Dependent Variable: CUSCI
Independent Variable: CUSCI_1 LBFC Auto(-4)

Size	85	Parameter:	3
Mean	7462.374	Std Dev	1741.739
R-Square	0.9994	DW	2.2967
SSE	3007516	MSE	35383

Term	CUSCI_1	LBFC	Auto(-4)
Estimate	0.9237	1.0101	-0.6224
Std Error	0.04	0.4792	0.0917
T-Ratio	23.11	2.11	-6.79
Pr>[t]	<.0001	0.038	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	9954.965	10366.26	10777.55
2006Q2	10087.68	10460.75	10833.81
2006Q3	10399.96	10777.05	11154.14
2006Q4	10168.3	10550.49	10932.68
2007Q1	10222.76	10608.78	10994.81
2007Q2	10299.57	10689.42	11079.26
2007Q3	10506.1	10899.83	11293.57
2007Q4	10371.5	10769.71	11167.92
2008Q1	10420.05	10821.96	11223.87
2008Q2	10466.73	10872.3	11277.88
2008Q3	10602.22	11011.42	11420.62
2008Q4	10547.64	10960.76	11373.88
2009Q1	10610.22	11026.85	11443.48
2009Q2	10659.22	11079.38	11499.53
2009Q3	10781.85	11205.52	11629.19
2009Q4	10761.58	11188.99	11616.4
2010Q1	10783.43	11214.32	11645.21
2010Q2	10835.44	11269.69	11703.94
2010Q3	10901.26	11338.86	11776.47
2010Q4	10894.05	11335.05	11776.06
2011Q1	10942.78	11386.98	11831.19
2011Q2	10981.49	11428.88	11876.27
2011Q3	11052.2	11502.73	11953.27
2011Q4	11063.25	11517	11970.74

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Number of Commercial and Industrial Customers Forecasting

Regression Model: D3
Dependent Variable: CUSCI
Independent Variable: CUSCI_1 GSP Auto(-4)

Size	85	Parameter:	3
Mean	7462.374	Std Dev	1741.739
R-Square	0.9994	DW	2.3068
SSE	3105003	MSE	36529

Term	CUSCI_1	GSP	Auto(-4)
Estimate	0.9525	0.0119	-0.6271
Std Error	0.0418	0.008926	0.0916
T-Ratio	22.81	1.33	-6.85
Pr>[t]	<.0001	0.1871	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	10044.22	10485.04	10925.86
2006Q2	10279.1	10676.89	11074.68
2006Q3	10682.14	11084.72	11487.29
2006Q4	10531.33	10940.22	11349.12
2007Q1	10718.24	11132.39	11546.54
2007Q2	10911.36	11331.28	11751.2
2007Q3	11239.05	11665.27	12091.49
2007Q4	11219.43	11653.11	12086.79
2008Q1	11412.35	11852.97	12293.58
2008Q2	11612.75	12060.79	12508.83
2008Q3	11897.74	12353.71	12809.69
2008Q4	11967.05	12431.87	12896.69
2009Q1	12169.44	12642.92	13116.39
2009Q2	12373.64	12856.25	13338.86
2009Q3	12630.82	13123.02	13615.23
2009Q4	12751.69	13254.19	13756.68
2010Q1	12955.75	13468.54	13981.32
2010Q2	13160.87	13684.34	14207.82
2010Q3	13398.39	13932.94	14467.5
2010Q4	13551.58	14097.74	14643.9
2011Q1	13756.08	14313.93	14871.78
2011Q2	13957.7	14527.57	15097.44
2011Q3	14179.54	14761.73	15343.93
2011Q4	14348.48	14943.37	15538.26

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Customers Forecasting

ARIMA Model (4,2,0)
Time Series: CUSCI

Size	1.331409	Parameters	5		
Mean	7462.374	Std Dev	1741.739		
R-Square	0.993631	DW	1.331409		
SSE	1096.782	MSE	1724694	RMSE	1313.276
Estimation					
Parameter	MU	AR1_1	AR1_2	AR1_3	AR1_4
Estimate	279.5836	0.627437	0.179011	-0.719115	0.386266
Standard Error	29.68743	0.090442	0.095932	0.10739	0.109028
t Value	9.417574	6.93745	1.866012	-6.696291	3.542809
FACTOR	0	1	1	1	1
Lag	0	1	3	4	5

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	10313.73	10601.51	10889.29
2006Q2	10244.72	10584.46	10924.19
2006Q3	10325.93	10684.06	11042.19
2006Q4	10230.52	10609.05	10987.58
2007Q1	10327.29	10750.86	11174.44
2007Q2	10318.03	10758.51	11198.98
2007Q3	10703.85	11152.66	11601.46
2007Q4	10414.57	10865.49	11316.41
2008Q1	10578.02	11092.37	11606.72
2008Q2	10598.54	11136.37	11674.2
2008Q3	10767.56	11313.08	11858.59
2008Q4	10615.81	11171.04	11726.27
2009Q1	10755.25	11352.37	11949.48
2009Q2	10723.01	11335.58	11948.15
2009Q3	11049.95	11670.53	12291.12
2009Q4	10807.54	11431.28	12055.01
2010Q1	10963.54	11629.54	12295.54
2010Q2	10994.96	11677.82	12360.68
2010Q3	11210.52	11898.92	12587.32
2010Q4	11028.06	11722.3	12416.54
2011Q1	11191.23	11921.78	12652.33
2011Q2	11166.34	11910.19	12654.04
2011Q3	11461.46	12211.95	12962.43
2011Q4	11243.18	11997.13	12751.08

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Number of Commercial and Industrial Customers Forecasting

Model:	Winters Exponential Smoothing Model
Var:	CUSCI
Method	Add Winters

Size	1.86041	Parameter:	6		
Mean	7462.374	Std Dev	1741.739		
R-Square	0.987845	DW	1.86041		
SSE	946.8496	MSE	3244799	RMSE	1801.333

	Constant	Linear	Quarter1	Quarter2	Quarter3	Quarter4
Estimate	10337.64	70.00981	92.29171	-48.25213	-33.26256	-10.77702
Weight	0.105573	0.105573	0.25	0.25	0.25	0.25

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	10112.41	10499.94	10887.47
2006Q2	10039.25	10429.4	10819.56
2006Q3	10121.11	10514.4	10907.7
2006Q4	10209.93	10606.9	11003.86
2007Q1	10378.61	10779.98	11181.34
2007Q2	10303.07	10709.44	11115.81
2007Q3	10382.44	10794.44	11206.45
2007Q4	10468.65	10886.94	11305.23
2008Q1	10634.64	11060.02	11485.4
2008Q2	10556.33	10989.48	11422.63
2008Q3	10632.88	11074.48	11516.09
2008Q4	10716.23	11166.98	11617.72
2009Q1	10879.36	11340.06	11800.75
2009Q2	10798.19	11269.52	11740.85
2009Q3	10871.88	11354.52	11837.17
2009Q4	10952.39	11447.02	11941.64
2010Q1	11112.73	11620.1	12127.46
2010Q2	11028.82	11549.56	12070.3
2010Q3	11099.81	11634.56	12169.31
2010Q4	11177.67	11727.06	12276.44
2011Q1	11335.44	11900.13	12464.82
2011Q2	11249.02	11829.6	12410.18
2011Q3	11317.56	11914.6	12511.64
2011Q4	11393.04	12007.1	12621.15

KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Commercial & Industrial Gas Use Per Customer Forecasting (Dth/Customer)(2006-2010)

Model		E1	E2	E3	ARIMA	Weighted C & I Use Per
Var	Dependent	USNCI	USNCI	USNCI	USNCI	
	Independent	PRCG	PRCG	PRCG		
		GSP	EMP	PCI		
		CDDN	CDDN	CDDN		
		AUTO(-4)	AUTO(-4)	AUTO(-4)		
Weight		25.00%	25.00%	25.00%	25.00%	100.00%

Commercial & Industrial Use Per Customer Forecast – Percent Growth from Base Year (2005)

	E1	E2	E3	ARIMA	Weighted
2006Q4-2007Q3	1.45%	-0.86%	0.98%	0.93%	0.63%
2007Q4-2008Q3	1.77%	-0.63%	1.28%	-1.74%	0.15%
2008Q4-2009Q3	2.19%	-0.53%	1.56%	-1.71%	0.38%
2009Q4-2010Q3	2.09%	-0.50%	1.54%	-0.30%	0.74%
2010Q4-2011Q3	2.05%	-0.49%	1.37%	0.43%	0.88%
Average	1.91%	-0.60%	1.35%	-0.48%	0.56%

Commercial & Industrial Use Per Customer Forecast (Annual)

	E1	E2	E3	ARIMA	Weighted
2005Q4-2006Q3	**733**	**724**	**728**	**765**	**738**
2006Q4-2007Q3	743	718	735	773	742
2007Q4-2008Q3	756	713	745	759	743
2008Q4-2009Q3	773	709	756	746	746
2009Q4-2010Q3	789	706	768	744	752
2010Q4-2011Q3	805	702	779	747	758
Average	767	712	752	756	747

Commercial & Industrial Use Per Customer Forecast (Quarterly)

	E1	E2	E3	ARIMA	Weighted
2005Q1	395	395	395	395	**395**
2005Q2	161	161	161	161	**161**
2005Q3	66	66	66	66	**66**
2005Q4	137	137	137	137	**137**
2006Q1	383	380	381	395	385
2006Q2	151	149	150	156	152
2006Q3	62	59	61	78	65
2006Q4	150	143	148	138	145
2007Q1	378	371	375	407	383
2007Q2	150	145	148	155	149
2007Q3	65	59	64	74	65
2007Q4	161	148	158	131	149
2008Q1	375	364	371	402	378
2008Q2	151	142	149	152	149
2008Q3	69	59	67	74	67
2008Q4	172	153	168	128	155
2009Q1	374	358	368	398	374
2009Q2	153	140	150	152	149
2009Q3	74	59	71	67	68
2009Q4	183	157	177	125	161
2010Q1	373	352	365	397	372
2010Q2	156	138	151	150	149
2010Q3	78	59	74	71	71
2010Q4	193	161	186	125	166
2011Q1	372	346	363	401	371
2011Q2	158	136	152	150	149
2011Q3	83	59	78	71	72
2011Q4	202	165	194	124	171

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Number of Commercial and Industrial Customers Forecasting

Regression Model: E1
Dependent Variable: USNCI
Independent Variable: PRCG_1 GSP CDDN Auto(-4)

Size	84	Parameter:	3
Mean	175.3273	Std Dev	99.54606
R-Square	0.9936	DW	1.6033
SSE	2275352	MSE	27088

Term	PRCG_1	GSP	CDDN	Auto(-4)
Estimate	-31.4242	0.0154	0.7471	-0.9091
Std Error	13.4085	0.005063	0.0826	0.0555
T-Ratio	-2.34	3.05	9.04	-16.38
Pr>[t]	0.0215	0.0031	<.0001	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	363.1864	382.9923	402.7981
2006Q2	131.1244	151.3293	171.5342
2006Q3	41.50724	61.60318	81.69913
2006Q4	129.984	150.124	170.2641
2007Q1	358.1547	378.1884	398.2221
2007Q2	129.5283	149.9125	170.2967
2007Q3	44.66131	64.94145	85.22159
2007Q4	140.5037	160.8159	181.1282
2008Q1	354.8179	375.0224	395.227
2008Q2	130.7385	151.2585	171.7785
2008Q3	48.79252	69.2115	89.63049
2008Q4	151.6309	172.0698	192.5088
2009Q1	353.3007	373.6332	393.9658
2009Q2	132.7717	153.3958	174.0199
2009Q3	53.28147	73.8072	94.33292
2009Q4	162.2438	182.7787	203.3136
2010Q1	352.1721	372.6043	393.0364
2010Q2	134.8213	155.5246	176.228
2010Q3	57.56071	78.16843	98.77614
2010Q4	172.1763	192.7846	213.3929
2011Q1	351.5866	372.0974	392.6081
2011Q2	137.0743	157.8396	178.6049
2011Q3	61.87784	82.55008	103.2223
2011Q4	181.6389	202.3044	222.9699

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Number of Commercial and Industrial Customers Forecasting

Regression Model: E2
Dependent Variable: USNCI
Independent Variable: PRCG_1 LBFC CDDN Auto(-4)

Size	84	Parameter:	3
Mean	175.3273	Std Dev	99.54606
R-Square	0.9936	DW	1.5239
SSE	2295214	MSE	27324

Term	PRCG_1	LBFC	CDDN	Auto(-4)
Estimate	-25.3783	1.0834	0.6731	-0.9262
Std Error	12.9077	0.4432	0.118	0.0513
T-Ratio	-1.97	2.44	5.7	-18.04
Pr>[t]	0.0526	0.0166	<.0001	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	359.98	379.662	399.3441
2006Q2	128.7001	148.7727	168.8454
2006Q3	38.76556	58.73124	78.69691
2006Q4	122.692	142.7091	162.7262
2007Q1	351.3861	371.3021	391.2182
2007Q2	124.4433	144.6866	164.9299
2007Q3	38.74699	58.88999	79.03299
2007Q4	127.5446	147.7343	167.9239
2008Q1	344.1133	364.2019	384.2906
2008Q2	121.7867	142.154	162.5213
2008Q3	38.6808	58.95328	79.22576
2008Q4	132.2109	152.5264	172.8419
2009Q1	337.6502	357.8657	378.0811
2009Q2	119.3455	139.8006	160.2557
2009Q3	38.67126	59.03672	79.40217
2009Q4	136.5994	157.0049	177.4103
2010Q1	331.6812	351.9882	372.2951
2010Q2	117.0984	137.6127	158.127
2010Q3	38.66634	59.09586	79.52538
2010Q4	140.6464	161.1135	181.5805
2011Q1	326.1261	346.4968	366.8674
2011Q2	114.9825	135.5334	156.0842
2011Q3	38.63003	59.10065	79.57127
2011Q4	144.3666	164.8728	185.379

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Number of Commercial and Industrial Customers Forecasting

Regression Model:	E3				
Dependent Variable:	USNCI				
Independent Variable:	PRCG_1	PCI	CDDN	Auto(-4)	

Size	84	Parameter:	3
Mean	175.3273	Std Dev	99.54606
R-Square	0.9937	DW	1.5946
SSE	2262254	MSE	26932

Term	PRCG_1	PCI	CDDN	Auto(-4)
Estimate	-30.4444	22.9306	0.7175	-0.9097
Std Error	13.19	7.2926	0.0875	0.0557
T-Ratio	-2.31	3.14	8.2	-16.33
Pr>[t]	0.0234	0.0023	<.0001	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	361.2463	380.9842	400.7221
2006Q2	129.6978	149.827	169.9561
2006Q3	40.78146	60.80308	80.8247
2006Q4	128.1086	148.1775	168.2463
2007Q1	355.1295	375.0937	395.0579
2007Q2	127.943	148.2459	168.5489
2007Q3	43.69852	63.89892	84.09931
2007Q4	137.7179	157.9537	178.1896
2008Q1	350.6594	370.7891	390.9188
2008Q2	128.3223	148.7521	169.182
2008Q3	46.99289	67.32371	87.65453
2008Q4	147.42	167.7757	188.1314
2009Q1	347.5832	367.8336	388.0841
2009Q2	129.2721	149.7941	170.3162
2009Q3	50.62733	71.05343	91.47953
2009Q4	156.8139	177.2554	197.6969
2010Q1	345.1363	365.4754	385.8145
2010Q2	130.3371	150.9244	171.5117
2010Q3	53.93042	74.4248	94.91918
2010Q4	165.2502	185.7528	206.2553
2011Q1	342.9017	363.3059	383.7101
2011Q2	131.3338	151.9658	172.5978
2011Q3	57.06275	77.60483	98.1469
2011Q4	173.1455	193.6898	214.2342

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Customers Forecasting

ARIMA Model (4,1,1)
Time Series: USNCI

Size	2.002519	Parameter:	6			
Mean	175.3273	Std Dev	99.54606			
R-Square	0.976265	DW	2.002519			
SSE	1108.223	MSE	1954101	RMSE	1397.892	
Estimation						
Parameter	MU	MA1_1	AR1_1	AR1_2	AR1_3	AR1_4
Estimate	5.787166	-0.249354	0.234703	-0.158219	0.115414	0.242861
Standard Error	34.49484	0.112279	0.111248	0.109153	0.10828	0.124106
t Value	0.167769	-2.220848	2.109725	-1.44952	1.065881	0
FACTOR	0	1	1	1	1	1
Lag	0	1	2	4	5	16

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	364.04	394.8654	425.6907
2006Q2	139.7442	156.2182	172.6922
2006Q3	61.27616	77.65878	94.04139
2006Q4	121.2904	137.6746	154.0588
2007Q1	390.392	406.6973	423.0027
2007Q2	137.841	154.5446	171.2483
2007Q3	56.98285	73.59889	90.21494
2007Q4	114.2049	130.8287	147.4525
2008Q1	385.1663	401.719	418.2717
2008Q2	135.5242	152.4283	169.3324
2008Q3	57.255	74.07523	90.89546
2008Q4	111.4769	128.3023	145.1278
2009Q1	381.3279	398.0864	414.8449
2009Q2	135.2179	152.2925	169.3671
2009Q3	50.3736	67.36704	84.36048
2009Q4	108.149	125.1581	142.1671
2010Q1	380.1741	397.1206	414.0672
2010Q2	133.0103	150.2512	167.492
2010Q3	54.14313	71.30614	88.46916
2010Q4	107.8109	124.9809	142.1509
2011Q1	383.9264	401.0357	418.1449
2011Q2	132.9415	150.3418	167.7421
2011Q3	53.38265	70.70731	88.03196
2011Q4	106.8181	124.1493	141.4805

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Number of Commercial and Industrial Customers Forecasting

Model:	Winters Exponential Smoothing Model
Var:	USNCI
Method	Add Winters

Size	2.003168	Parameter:	5		
Mean	175.3273	Std Dev	99.54606		
R-Square	0.957198	DW	2.003168		
SSE	957.3116	MSE	3732493	RMSE	1931.966

	Constant	Linear	Quarter1	Quarter2	Quarter3	Quarter4
Estimate	1871.884	0	1810.776	-410.7561	-1179.696	-220.3243
Weight	0.2	0.2	0.25	0.25	0.25	0.25

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	352.7843	368.266	383.7477
2006Q2	130.3394	146.1128	161.8862
2006Q3	53.52792	69.21885	84.90977
2006Q4	149.4409	165.156	180.8711
2007Q1	352.6394	368.266	383.8926
2007Q2	130.2136	146.1128	162.012
2007Q3	53.3989	69.21885	85.03879
2007Q4	149.3135	165.156	180.9984
2008Q1	352.5088	368.266	384.0232
2008Q2	130.0997	146.1128	162.1258
2008Q3	53.2821	69.21885	85.15559
2008Q4	149.1982	165.156	181.1138
2009Q1	352.3904	368.266	384.1416
2009Q2	129.9963	146.1128	162.2293
2009Q3	53.17587	69.21885	85.26182
2009Q4	149.0932	165.156	181.2187
2010Q1	352.2826	368.266	384.2494
2010Q2	129.9018	146.1128	162.3238
2010Q3	53.07882	69.21885	85.35887
2010Q4	148.9973	165.156	181.3146
2011Q1	352.1841	368.266	384.348
2011Q2	129.8152	146.1128	162.4104
2011Q3	52.98981	69.21885	85.44789
2011Q4	148.9093	165.156	181.4026

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Commercial & Industrial Gas Consumption Forecasting (Dth) (2006 – 2010)

Model Var		F1	F2	F3	ARIMA	Weighted C & I Sale	Calculated Sales	Combined (50/50)
	Dependent	GSNCI	GSNCI	GSNCI	USNCI			
	Independent	GSNCI_1 PRCG AUTO(-4)	PRCG AUTO(-4) AUTO(-8)	GSNCI_1 PRCG AUTO(-4) AUTO(-8)				
Weight		20.00%	20.00%	20.00%	40.00%	100.00%		

Commercial & Industrial Gas Sales Forecast (Percent Growth from Base Year (2005)

	F1	F2	F3	ARIMA	Weighted C & I Sale	Calculated Sales	Combined (50/50)
2006Q4-2007Q3	5.34%	2.73%	5.55%	5.46%	4.87%	3.57%	6.85%
2007Q4-2008Q3	4.03%	1.56%	3.78%	2.75%	2.96%	3.34%	3.15%
2008Q4-2009Q3	3.53%	1.60%	3.33%	0.09%	1.72%	3.51%	2.59%
2009Q4-2010Q3	3.09%	1.71%	2.95%	2.20%	2.43%	3.85%	3.12%
2010Q4-2011Q3	2.75%	1.81%	2.64%	3.69%	2.90%	3.84%	3.36%
Average	3.75%	1.88%	3.65%	2.84%	2.98%	3.62%	3.81%

Commercial & Industrial Gas Sales Forecast (Dth) (Annual)

	F1	F2	F3	ARIMA	Weighted C & I Sale	Calculated Sales	Combined (50/50)
2005Q4-2006Q3	**7,924,343**	8,628,982	**7,919,898**	**8,067,522**	**8,121,654**	**7,734,162**	**7,734,162**
2006Q4-2007Q3	8,347,166	8,864,129	8,359,073	8,508,086	8,517,308	8,010,453	8,263,881
2007Q4-2008Q3	8,683,945	9,002,617	8,675,271	8,742,207	8,769,249	8,278,350	8,523,800
2008Q4-2009Q3	8,990,327	9,146,297	8,964,552	8,749,767	8,920,142	8,569,259	8,744,701
2009Q4-2010Q3	9,268,498	9,302,969	9,228,745	8,942,571	9,137,071	8,898,799	9,017,935
2010Q4-2011Q3	9,523,502	9,471,707	9,472,064	9,272,510	9,402,459	9,240,153	9,321,306
Average	8,789,630	9,069,450	8,769,934	8,713,777	8,811,314	8,455,196	8,600,964

Commercial & Industrial Gas Sales Forecast (Dth) (Quarterly)

	F1	F2	F3	ARIMA	Weighted C & I Sale	Calculated Sales	Combined (50/50)
2005Q1	**3,969,780**	**3,969,780**	**3,969,780**	**3,969,780**	**3,969,780**	3,969,780	3,969,780
2005Q2	**1,645,482**	**1,645,482**	**1,645,482**	**1,645,482**	**1,645,482**	1,645,482	1,645,482
2005Q3	**708,090**	**708,090**	**708,090**	**708,090**	**708,090**	708,090	708,090
2005Q4	**1,410,809**	**1,410,809**	**1,410,809**	**1,410,809**	**1,410,809**	1,410,809	1,410,809
2006Q1	3,692,222	3,880,956	3,707,906	4,114,267	3,901,924	4,024,862	3,963,393
2006Q2	1,813,328	2,342,509	1,797,889	1,747,723	1,889,834	1,594,698	1,742,266
2006Q3	1,007,984	994,709	1,003,293	794,723	919,086	696,737	807,911
2006Q4	1,568,394	1,388,746	1,575,371	1,519,931	1,514,475	1,541,227	1,527,851
2007Q1	3,554,583	3,551,825	3,596,040	4,265,976	3,846,880	4,126,266	3,986,573
2007Q2	1,959,766	2,690,215	1,944,099	1,832,279	2,051,727	1,618,709	1,835,218
2007Q3	1,264,423	1,233,343	1,243,563	889,900	1,104,226	724,251	914,238
2007Q4	1,723,803	1,356,013	1,718,470	1,493,894	1,557,215	1,641,576	1,599,396
2008Q1	3,416,180	3,258,284	3,466,937	4,422,443	3,797,257	4,207,907	4,002,582
2008Q2	2,068,023	2,905,675	2,047,880	1,891,434	2,160,889	1,663,479	1,912,184
2008Q3	1,475,938	1,482,645	1,441,984	934,436	1,253,888	765,388	1,009,638
2008Q4	1,859,170	1,362,417	1,844,405	1,504,657	1,615,061	1,760,113	1,687,587
2009Q1	3,307,383	3,014,925	3,363,528	4,412,323	3,702,096	4,298,721	4,000,409
2009Q2	2,163,409	3,037,947	2,139,859	1,934,546	2,242,061	1,715,810	1,978,936
2009Q3	1,660,365	1,731,008	1,616,760	898,242	1,360,923	794,615	1,077,769
2009Q4	1,983,410	1,407,841	1,961,164	1,512,351	1,675,424	1,879,656	1,777,540
2010Q1	3,218,219	2,816,523	3,276,892	4,471,147	3,650,786	4,400,227	4,025,506
2010Q2	2,247,336	3,111,583	2,221,393	2,019,492	2,323,859	1,767,483	2,045,671
2010Q3	1,819,534	1,967,022	1,769,296	939,580	1,487,002	851,433	1,169,218
2010Q4	2,093,823	1,486,236	2,066,129	1,587,970	1,764,426	2,002,102	1,883,264
2011Q1	3,149,039	2,658,407	3,207,782	4,555,481	3,625,238	4,518,524	4,071,881
2011Q2	2,321,290	3,143,414	2,293,562	2,099,844	2,391,591	1,821,568	2,106,580
2011Q3	1,959,350	2,183,651	1,904,591	1,029,215	1,621,204	897,959	1,259,581
2011Q4	2,193,962	1,590,689	2,162,153	1,632,147	1,842,220	2,123,846	1,983,033

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Commercial and Industrial Gas Comsumption (Dth) Forecasting

Regression Model: F1
Dependent Variable: GSNCI
Independent Variable: GSNCI_1 PRCCI Auto(-4)

Size	85	Parameter:	3
Mean	1074400	Std Dev	678186.6
R-Square	0.9802	DW	1.9972
SSE	4.57E+14	MSE	5.37E+12

Term	GSNCI_1	PRCCI	Auto(-4)
0	0.4874	517287	-0.854699
0	0.0921	151317	0.056307
0	5.29	3.42	-15.17927
0	<.0001	0.001	0

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	3084476	3692222	4299969
2006Q2	1634936	1813328	1991719
2006Q3	830218.9	1007984	1185749
2006Q4	1391476	1568394	1745311
2007Q1	3378544	3554583	3730622
2007Q2	1777443	1959766	2142089
2007Q3	1082543	1264423	1446303
2007Q4	1542883	1723803	1904722
2008Q1	3236017	3416180	3596344
2008Q2	1882995	2068023	2253052
2008Q3	1291220	1475938	1660656
2008Q4	1675385	1859170	2042956
2009Q1	3124226	3307383	3490540
2009Q2	1976404	2163409	2350414
2009Q3	1473558	1660365	1847171
2009Q4	1797443	1983410	2169377
2010Q1	3032751	3218219	3403686
2010Q2	2058789	2247336	2435882
2010Q3	1631094	1819534	2007974
2010Q4	1906105	2093823	2281542
2011Q1	2961702	3149039	3336375
2011Q2	2131452	2321290	2511128
2011Q3	1769546	1959350	2149154
2011Q4	2004756	2193962	2383169

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Commercial and Industrial Gas Comsumption (Dth) Forecasting

Regression Model: F2
Dependent Variable: GSNCI
Independent Variable: PRCCI Auto(-1) Auto(-2) Auto(-3) Auto(-4)

Size	84	Parameter:	3
Mean	1074400	Std Dev	678186.6
R-Square	0.9691	DW	1.4073
SSE	7.16E+14	MSE	8.53E+12

Term		PRCCI	Auto(-1)	Auto(-2)	Auto(-3)	Auto(-4)
	0	1326293	-0.136698	0.125686	0.017356	-0.780446
	0	131058	0.068217	0.069803	0.069803	0.068217
	0	10.12	-2.00387	1.800582	0.248643	-11.44064
	0	<.0001	0	0	0	0

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	3166714	3880956	4595198
2006Q2	1652030	2342509	3032988
2006Q3	290182.3	994708.6	1699235
2006Q4	657924.3	1388746	2119568
2007Q1	2692828	3551825	4410822
2007Q2	1837167	2690215	3543263
2007Q3	371162.5	1233343	2095524
2007Q4	477569.3	1356013	2234456
2008Q1	2310417	3258284	4206151
2008Q2	1953390	2905675	3857961
2008Q3	523751.6	1482645	2441537
2008Q4	390994	1362417	2333841
2009Q1	2004347	3014925	4025502
2009Q2	2017421	3037947	4058473
2009Q3	705986.5	1731008	2756029
2009Q4	371842.2	1407841	2443840
2010Q1	1758559	2816523	3874487
2010Q2	2041240	3111583	4181925
2010Q3	893877.2	1967022	3040166
2010Q4	402952.9	1486236	2569518
2011Q1	1563150	2658407	3753664
2011Q2	2035333	3143414	4251495
2011Q3	1073917	2183651	3293385
2011Q4	471578.9	1590689	2709799

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Commercial and Industrial Gas Comsumption (Dth) Forecasting

Regression Model: F3
Dependent Variable: GSNCI
Independent Variable: GSNCI_1 PRCCI Auto(-4) Auto(-8)

Size	84	Parameter:	4
Mean	1074400	Std Dev	678186.6
R-Square	0.9806	DW	2.0006
SSE	4.47E+14	MSE	5.33E+12

Term		GSNCI_1	PRCCI	Auto(-4)	Auto(-8)
	0	0.4897	501164	-0.816044	-0.045227
	0	0.0928	151400	0.108997	0.108997
	0	5.28	3.31	-7.486848	-0.414938
	0	<.0001	0.0014	0	0

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	3100213	3707906	4315599
2006Q2	1618996	1797889	1976783
2006Q3	825052.9	1003293	1181533
2006Q4	1397977	1575371	1752765
2007Q1	3419522	3596040	3772558
2007Q2	1761053	1944099	2127146
2007Q3	1060993	1243563	1426132
2007Q4	1536859	1718470	1900081
2008Q1	3286092	3466937	3647781
2008Q2	1861911	2047880	2233850
2008Q3	1256370	1441984	1627597
2008Q4	1659736	1844405	2029074
2009Q1	3179511	3363528	3547544
2009Q2	1951742	2139859	2327977
2009Q3	1428895	1616760	1804625
2009Q4	1774169	1961164	2148159
2010Q1	3090434	3276892	3463350
2010Q2	2031620	2221393	2411166
2010Q3	1579689	1769296	1958902
2010Q4	1877292	2066129	2254965
2011Q1	3019376	3207782	3396189
2011Q2	2102440	2293562	2484684
2011Q3	1713567	1904591	2095615
2011Q4	1971790	2162153	2352516

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Commercial and Industrial Gas Comsumption (Dth) Forecasting

ARIMA Model (3,1,0)
Time Series: GSNCI

Size	85	Parameters	4		
Mean	1340528.354	Std Dev	902070.4028		
R-Square	0.981428056	DW	1.990617189		
SSE	1.26604E+14	MSE	1.56301E+12	RMSE	1250206
Estimation					
Parameter	MU	AR1_1	AR1_2	AR1_3	
Estimate	591532.9542	0.13805071	-0.25552873	0.258268	
Standard Error	153261.3229	0.10426159	0.116155612	0.128794	
t Value	3.859636228	1.32408029	-2.199882784	2.005288	
FACTOR	0	1	1	1	
Lag	0	2	10	16	

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	3869231	4114267	4359303
2006Q2	1502687	1747723	1992759
2006Q3	547363	794723	1042083
2006Q4	1272572	1519931	1767291
2007Q1	3914494	4265976	4617459
2007Q2	1480796	1832279	2183761
2007Q3	536731	889900	1243069
2007Q4	1140726	1493894	1847063
2008Q1	3989863	4422443	4855023
2008Q2	1458854	1891434	2324014
2008Q3	500942	934436	1367929
2008Q4	1071163	1504657	1938151
2009Q1	3920411	4412323	4904235
2009Q2	1442634	1934546	2426457
2009Q3	405309	898242	1391174
2009Q4	1019419	1512351	2005284
2010Q1	3896615	4471147	5045679
2010Q2	1444960	2019492	2594024
2010Q3	364869	939580	1514291
2010Q4	1013259	1587970	2162682
2011Q1	3900232	4555481	5210729
2011Q2	1444596	2099844	2755092
2011Q3	373928	1029215	1684501
2011Q4	976861	1632147	2287434

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Commercial and Industrial Gas Comsumption (Dth) Forecasting

Winters Exponential Smoothing Model
Var: GSNCI

Size	83	Parameters	6		
Mean	1340528	Std Dev	902070.4028		
R-Square	0.931591	DW	2.27798452		
SSE	7.16E+15	MSE	4.89869E+14	RMSE	22132979

	Constant	Linear	Quarter1	Quarter2	Quarter3	Quarter4
Estimate	20162984	67757.6	17484197.71	-3753627	-11125270	-2605300
Weight	0.105573	0.105573	0.25	0.25	0.25	0.25

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	3295338	3771494	4247649.505
2006Q2	1175099	1654487	2133875.159
2006Q3	440859.9	924098.6	1407337.347
2006Q4	1295121	1782871	2270622.101
2007Q1	3305440	3798597	4291754.234
2007Q2	1182282	1681590	2180898.291
2007Q3	444970	951201.7	1457433.374
2007Q4	1296023	1809974	2323925.979
2008Q1	3303034	3825700	4348366.419
2008Q2	1176480	1708693	2240906.72
2008Q3	435704	978304.7	1520905.455
2008Q4	1283246	1837077	2390909.134
2009Q1	3286743	3852803	4418862.767
2009Q2	1156669	1735796	2314923.183
2009Q3	412382.5	1005408	1598432.998
2009Q4	1256436	1864180	2471924.464
2010Q1	3256511	3879906	4503300.701
2010Q2	1123063	1762899	2402735.632
2010Q3	375458.3	1032511	1689563.333
2010Q4	1216258	1891284	2566309.194
2011Q1	3213175	3907009	4600843.61
2011Q2	1076641	1790002	2503363.604
2011Q3	326026.9	1059614	1793200.836
2011Q4	1163894	1918387	2672879.35

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Customers Forecasting (2006 -- 2010)

Model Var		A1	A2	A3	A4	ARIMA	Winter's	Weighted Residential Customers
	Dependent	CUSR	CUSR	CUSR	CUSR	CUSR	CUSR	
	Independent	Intercept CUSR_1 GSP AUTO(-4)	CUSR_1 EMP AUTO(-4)	CUSR_1 POP AUTO(-4)	CUSR_1 GSP POP AUTO(-4)			
	Weight	15.00%	15.00%	15.00%	15.00%	20.00%	20.00%	100.00%

Residential Customer Forecast -- Percent Growth from Base Year (2005)

	A1	A2	A3	A4	ARIMA	Winter's	Weighted
2006Q4-2007Q3	2.90%	0.78%	0.83%	2.49%	2.79%	2.40%	2.09%
2007Q4-2008Q3	3.03%	0.80%	0.79%	2.52%	2.21%	2.02%	1.93%
2008Q4-2009Q3	3.15%	0.77%	0.71%	2.59%	1.56%	1.98%	1.81%
2009Q4-2010Q3	3.06%	0.74%	0.66%	2.47%	1.83%	1.94%	1.82%
2010Q4-2011Q3	2.94%	0.77%	0.68%	2.35%	1.95%	1.91%	1.81%
Average	3.02%	0.77%	0.73%	2.48%	2.07%	2.05%	1.89%

Residential Customer Forecast (Annual)

	A1	A2	A3	A4	ARIMA	Winter's	Weighted
2005Q4-2006Q3	**72,552**	**71,950**	**71,981**	**72,470**	**72,768**	**72,263**	**72,349**
2006Q4-2007Q3	74,659	72,510	72,575	74,273	74,799	73,995	73,861
2007Q4-2008Q3	76,917	73,089	73,150	76,145	76,449	75,492	75,283
2008Q4-2009Q3	79,342	73,653	73,672	78,114	77,644	76,988	76,644
2009Q4-2010Q3	81,772	74,197	74,155	80,039	79,067	78,485	78,035
2010Q4-2011Q3	84,172	74,772	74,660	81,918	80,612	79,981	79,447
Average	78,236	73,362	73,366	77,160	76,890	76,201	75,937

Residential Customer Forecast (Quarterly)

	A1	A2	A3	A4	ARIMA	Winter's	Weighted
2005Q1	**71,607**	**71,607**	**71,607**	**71,607**	**71,607**	**71,607**	**71,607**
2005Q2	**71,575**	**71,575**	**71,575**	**71,575**	**71,575**	**71,575**	**71,575**
2005Q3	**73,331**	**73,331**	**73,331**	**73,331**	**73,331**	**73,331**	**73,331**
2005Q4	**69,487**	**69,487**	**69,487**	**69,487**	**69,487**	**69,487**	**69,487**
2006Q1	72,797	72,391	72,419	72,754	73,887	72,997	72,931
2006Q2	73,122	72,267	72,305	73,013	72,708	72,921	72,732
2006Q3	74,803	73,656	73,715	74,626	74,991	73,647	74,248
2006Q4	71,966	70,425	70,457	71,721	71,279	71,926	71,326
2007Q1	74,814	72,874	72,944	74,476	75,949	74,493	74,355
2007Q2	75,191	72,779	72,850	74,758	75,527	74,417	74,326
2007Q3	76,664	73,963	74,050	76,139	76,440	75,144	75,439
2007Q4	74,521	71,306	71,344	73,911	73,470	73,423	73,041
2008Q1	76,957	73,378	73,452	76,240	77,566	75,990	75,715
2008Q2	77,426	73,334	73,395	76,599	76,820	75,914	75,660
2008Q3	78,766	74,340	74,410	77,829	77,939	76,640	76,718
2008Q4	77,206	72,148	72,152	76,165	74,526	74,919	74,540
2009Q1	79,313	73,891	73,926	78,148	78,990	77,487	77,087
2009Q2	79,821	73,857	73,873	78,530	78,049	77,411	77,004
2009Q3	81,028	74,714	74,736	79,612	79,013	78,137	77,944
2009Q4	79,891	72,906	72,853	78,356	76,156	76,416	76,115
2010Q1	81,692	74,380	74,355	80,025	80,125	78,983	78,390
2010Q2	82,216	74,384	74,337	80,417	79,426	78,907	78,370
2010Q3	83,287	75,120	75,076	81,359	80,559	79,633	79,265
2010Q4	82,490	73,648	73,526	80,437	77,614	77,912	77,621
2011Q1	84,055	74,908	74,813	81,867	81,904	80,480	79,823
2011Q2	84,586	74,942	74,826	82,263	80,784	80,404	79,730
2011Q3	85,558	75,588	75,477	83,103	82,145	81,130	80,614
2011Q4	85,030	74,395	74,208	82,449	79,138	79,409	79,122

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Customers Forecasting

Regression Model: A1
Dependent Variable: CUSR
Independent Variable: Intercept CUSR_1 GSP Auto(-4)

Size	84	Parameter:	3
Mean	57113.37	Std Dev	8831.98
R-Square	0.9914	DW	2.4907
SSE	55608441	MSE	662005

Term	Intercept	CUSR_1	GSP	Auto(-4)
Estimate	7114	0.802	0.1337	-0.8028
Std Error	2382	0.0698	0.0562	0.0793
T-Ratio	2.99	11.5	2.38	-10.12
Pr>[t]	0.0037	<.0001	0.0196	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	70595.78	72797.39	74999
2006Q2	72215.47	73122.49	74029.51
2006Q3	73890.36	74803.28	75716.19
2006Q4	71044.64	71966.17	72887.69
2007Q1	73890.27	74814.05	75737.84
2007Q2	74260.35	75191.17	76121.99
2007Q3	75725.88	76663.68	77601.47
2007Q4	73574.32	74521.22	75468.11
2008Q1	76005.58	76956.64	77907.69
2008Q2	76467.36	77426.43	78385.5
2008Q3	77798.5	78765.63	79732.77
2008Q4	76229.15	77206.07	78182.99
2009Q1	78330.05	79312.96	80295.86
2009Q2	78828.81	79820.79	80812.78
2009Q3	80026.77	81027.89	82029
2009Q4	78879.57	79891.16	80902.75
2010Q1	80673.02	81692.09	82711.17
2010Q2	81187.02	82215.96	83244.91
2010Q3	82248.36	83287.2	84326.04
2010Q4	81440.04	82489.77	83539.5
2011Q1	82996.91	84055.19	85113.48
2011Q2	83517.72	84586.4	85655.07
2011Q3	84478.9	85557.96	86637.02
2011Q4	83940.14	85030.32	86120.49

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Customers Forecasting

Regression Model: A2
Dependent Variable: CUSR
Independent Variable: CUSR_1 LBFC Auto(-4)

Size	85	Parameter:	3
Mean	57113.37	Std Dev	8831.98
R-Square	0.9955	DW	2.4531
SSE	55010975	MSE	647188

Term	CUSR_1	LBFC	Auto(-4)
Estimate	0.8242	16.3452	-0.8328
Std Error	0.0595	5.4189	0.0767
T-Ratio	13.85	3.02	-10.86
Pr>[t]	<.0001	0.0034	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	70473.46	72391.32	74309.19
2006Q2	71376.95	72266.65	73156.35
2006Q3	72761.36	73655.72	74550.08
2006Q4	69523.92	70425.04	71326.16
2007Q1	71973.16	72874.47	73775.79
2007Q2	71873.79	72779.1	73684.41
2007Q3	73054.25	73962.82	74871.39
2007Q4	70392.59	71305.98	72219.38
2008Q1	72465.11	73378.43	74291.75
2008Q2	72417.56	73333.7	74249.84
2008Q3	73421.08	74339.51	75257.94
2008Q4	71226.39	72148.28	73070.18
2009Q1	72969.08	73890.71	74812.34
2009Q2	72933.48	73857.05	74780.63
2009Q3	73789.4	74714.49	75639.58
2009Q4	71978.77	72906.27	73833.77
2010Q1	73452.85	74379.9	75306.95
2010Q2	73455.47	74383.77	75312.07
2010Q3	74190.68	75119.92	76049.16
2010Q4	72717.61	73648.47	74579.34
2011Q1	73977.57	74907.87	75838.17
2011Q2	74010.84	74941.91	75872.98
2011Q3	74656.71	75588.32	76519.93
2011Q4	73462.42	74395.11	75327.8

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EnergyNorth Natural Gas Inc.
Residential Customers Forecasting

Regression Model:	A3		
Dependent Variable:	CUSR		
Independent Variable:	CUSR_1	POP	Auto(-4)

Size	85	Parameters	3
Mean	57113.37	Std Dev	8831.98
R-Square	0.9952	DW	2.4606
SSE	55375565	MSE	651477

Term	CUSR_1	POP	Auto(-4)
Estimate	0.8424	8.1299	-0.8383
Std Error	0.0562	2.8331	0.0767
T-Ratio	15	2.87	-10.94
Pr>[t]	<.0001	0.0052	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	70475.51	72418.79	74362.08
2006Q2	71414.99	72304.8	73194.61
2006Q3	72820.05	73714.6	74609.15
2006Q4	69555.35	70456.77	71358.19
2007Q1	72042.58	72944.24	73845.91
2007Q2	71944.11	72849.89	73755.67
2007Q3	73141.28	74050.43	74959.58
2007Q4	70429.72	71343.84	72257.96
2008Q1	72537.5	73451.58	74365.66
2008Q2	72478.26	73395.26	74312.26
2008Q3	73490.66	74410.02	75329.38
2008Q4	71229.06	72151.97	73074.89
2009Q1	73003.25	73925.88	74848.51
2009Q2	72948.9	73873.5	74798.1
2009Q3	73810.13	74736.24	75662.35
2009Q4	71924.11	72852.63	73781.16
2010Q1	73427.17	74355.15	75283.13
2010Q2	73407.39	74336.57	75265.74
2010Q3	74145.92	75075.94	76005.97
2010Q4	72594.49	73526.06	74457.62
2011Q1	73882.54	74813.38	75744.23
2011Q2	73894.07	74825.55	75757.03
2011Q3	74544.69	75476.55	76408.42
2011Q4	73274.98	74207.78	75140.59

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Residential Customers Forecasting

Regression Model: A4
Dependent Variable: CUSR
Independent Variable: CUSR_1 GSP POP Auto(-4)

Size	84	Parameter:	3
Mean	57113.37	Std Dev	8831.98
R-Square	0.9968	DW	2.3198
SSE	51931756	MSE	618235

Term	CUSR_1	GSP	POP	Auto(-4)
Estimate	0.6895	0.1177	12.1407	-0.8026
Std Error	0.0816	0.0461	3.0887	0.0777
T-Ratio	8.45	2.55	3.93	-10.33
Pr>[t]	<.0001	0.0125	0.0002	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	70628.92	72753.82	74878.73
2006Q2	72108.3	73013.35	73918.4
2006Q3	73714.91	74625.68	75536.45
2006Q4	70802.07	71721.12	72640.18
2007Q1	73554.86	74475.82	75396.77
2007Q2	73830.34	74757.74	75685.15
2007Q3	75205.13	76138.77	77072.42
2007Q4	72969.1	73910.91	74852.73
2008Q1	75294.73	76239.81	77184.9
2008Q2	75646.61	76598.55	77550.48
2008Q3	76870.36	77829.05	78787.75
2008Q4	75197.56	76164.55	77131.53
2009Q1	77176.53	78148.05	79119.57
2009Q2	77550.86	78529.74	79508.61
2009Q3	78625.54	79611.69	80597.83
2009Q4	77361.67	78356.25	79350.82
2010Q1	79025.01	80025.08	81025.15
2010Q2	79409.37	80417.08	81424.8
2010Q3	80343.45	81358.71	82373.97
2010Q4	79413.4	80437.05	81460.71
2011Q1	80837.06	81866.84	82896.62
2011Q2	81225.95	82263.49	83301.03
2011Q3	82058.05	83103.26	84148.46
2011Q4	81395.93	82449.41	83502.9

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Residential Customers Forecasting

ARIMA Model (3,2,2)
Time Series: CUSR

Size	84	Parameters	6			
Mean	57113.3722	Std Dev	8831.98			
R-Square	0.99216725	DW	2.133572			
SSE	38863779.4	MSE	504724.4	RMSE	710.4396	
Estimation						
Parameter	MU	MA1_1	MA1_2	AR1_1	AR1_2	AR1_3
Estimate	-15.9515596	0.203073	0.110084	-0.445459	-0.411138	-0.491715
Standard Error	21.0663524	0.121847	0.126043	0.119616	0.120134	0.155974
t Value	-0.75720558	1.666621	0.87338	-3.724076	-3.422331	-3.152546
FACTOR	0	1	1	1	1	1
Lag	0	1	4	3	6	9

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	72494.1669	73886.6	75279.04
2006Q2	70927.2022	72707.72	74488.24
2006Q3	72893.3057	74991.31	77089.31
2006Q4	69125.0871	71279.41	73433.74
2007Q1	73106.2917	75948.88	78791.47
2007Q2	72278.8665	75527.05	78775.23
2007Q3	72950.4635	76440.13	79929.79
2007Q4	69893.7461	73470.33	77046.92
2008Q1	73393.9933	77566.46	81738.92
2008Q2	72362.6781	76820.16	81277.64
2008Q3	73277.3314	77939.19	82601.05
2008Q4	69782.7095	74525.68	79268.64
2009Q1	73701.3257	78989.53	84277.73
2009Q2	72472.6391	78049.39	83626.14
2009Q3	73220.03	79012.89	84805.74
2009Q4	70171.5307	76156.35	82141.17
2010Q1	73487.5314	80125.34	86763.16
2010Q2	72400.5039	79426.45	86452.4
2010Q3	73222.9286	80559.46	87895.99
2010Q4	70010.4474	77614.33	85218.21
2011Q1	73588.799	81904.35	90219.91
2011Q2	72052.1459	80784.43	89516.7
2011Q3	73061.9064	82145.02	91228.14
2011Q4	69746.3698	79137.8	88529.22

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EnergyNorth Natural Gas Inc.
Residential Customers Forecasting

Model:	Winters Exponential Smoothing Model
Var:	CUSR
Method	Add Winters

Size	83	Parameter:	6		
Mean	57113.37	Std Dev	8831.98		
R-Square	0.977041	DW	1.622063		
SSE	1.58E+08	MSE	1898747	RMSE	1377.95

	Constant	Linear	Quarter1	Quarter2	Quarter3	Quarter4
Estimate	71937.27	374.1495	685.325	235.1703	587.381	-1507.876
Weight	0.105573	0.105573	0.25	0.25	0.25	0.25

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	70296.01	72996.74	75697.48
2006Q2	70201.67	72920.74	75639.81
2006Q3	70906.19	73647.1	76388.01
2006Q4	69159.49	71925.99	74692.49
2007Q1	71696.18	74493.34	77290.51
2007Q2	71585.28	74417.34	77249.39
2007Q3	72272.37	75143.7	78015.02
2007Q4	70507.48	73422.59	76337.7
2008Q1	73025.4	75989.94	78954.48
2008Q2	72895.24	75913.94	78932.63
2008Q3	73562.69	76640.3	79717.9
2008Q4	71777.88	74919.19	78060.5
2009Q1	74275.87	77486.54	80697.2
2009Q2	74125.75	77410.53	80695.32
2009Q3	74773.28	78136.89	81500.51
2009Q4	72968.69	76415.79	79862.88
2010Q1	75447.27	78983.14	82519
2010Q2	75278.01	78907.13	82536.25
2010Q3	75906.72	79633.49	83360.26
2010Q4	74083.67	77912.38	81741.1
2011Q1	76544.34	80479.73	84415.13
2011Q2	76357.58	80403.73	84449.88
2011Q3	76969.22	81130.09	85290.96
2011Q4	75129.53	79408.98	83688.43

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Gas Use Per Customer Forecasting (Dth/Customer)(2006-2010)

Model		B1	B2	ARIMA	Winter's	Weighted Residential Use Per
Var	Dependent	USNR	USNR	USNR	USNR	
	Independent	PRCG_1	PRCG_1			
		GSP	PCI			
		CDDN	CDDN			
		AUTO(-4)	AUTO(-4)			
Weight		20.00%	20.00%	30.00%	30.00%	100.00%

Residential Use Per Customer Forecast -- Percent Growth from Base Year (2005)					
2006Q4-2007Q3	1.21%	0.97%	-2.13%	2.81%	0.77%
2007Q4-2008Q3	1.24%	1.00%	3.34%	-0.84%	1.17%
2008Q4-2009Q3	1.34%	1.03%	-0.76%	-0.84%	0.39%
2009Q4-2010Q3	1.22%	0.94%	-1.09%	-0.85%	0.26%
2010Q4-2011Q3	1.14%	0.81%	-0.59%	-0.86%	0.31%
Average	1.23%	0.95%	-0.24%	-0.11%	0.58%

Residential Use Per Customer Forecast (Annual)					
2005Q4-2006Q3	**85**	**85**	**88**	**85**	**86**
2006Q4-2007Q3	86	86	86	88	86
2007Q4-2008Q3	87	86	89	87	87
2008Q4-2009Q3	88	87	88	86	88
2009Q4-2010Q3	90	88	87	86	88
2010Q4-2011Q3	91	89	86	85	88
Average	88	87	87	86	87

Residential Use Per Customer Forecast (Quarterly)					
2005Q1	**51**	**51**	**51**	**51**	**51**
2005Q2	**16**	**16**	**16**	**16**	**16**
2005Q3	**5**	**5**	**5**	**5**	**5**
2005Q4	**16**	**16**	**16**	**16**	**16**
2006Q1	49	49	52	48	49
2006Q2	15	15	14	16	15
2006Q3	5	5	5	5	5
2006Q4	19	19	15	19	18
2007Q1	48	47	52	48	49
2007Q2	15	15	13	16	15
2007Q3	5	5	5	5	5
2007Q4	21	21	15	19	19
2008Q1	47	46	53	48	48
2008Q2	15	14	14	15	15
2008Q3	5	5	6	5	5
2008Q4	23	23	14	19	20
2009Q1	46	45	53	48	48
2009Q2	15	14	14	15	14
2009Q3	5	5	6	5	5
2009Q4	24	24	14	18	21
2010Q1	45	45	53	48	47
2010Q2	15	14	13	15	14
2010Q3	5	5	6	4	5
2010Q4	26	25	14	18	22
2011Q1	45	44	53	47	47
2011Q2	15	14	13	15	14
2011Q3	6	5	6	4	5
2011Q4	27	26	14	18	22

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Gas Use Per Customer Forecasting

Regression Model:	B1				
Dependent Variable:	USNR				
Independent Variable:	PRCG_1	GSP	CDDN	Auto(-4)	

Size	84	Parameters	4
Mean	23.3816	Std Dev	14.09718
R-Square	0.9944	DW	1.9741
SSE	36230.36	MSE	431.3138

Term	PRCG_1	GSP	CDDN	Auto(-4)
Estimate	-19.9013	7.73E-04	0.1125	-0.824984
Std Error	17.731	4.74E-04	0.006663	0.061664
T-Ratio	-1.12	1.63	16.88	-13.38
Pr>[t]	0.2649	0.1065	<.0001	

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	47.5282	49.035953	50.5437
2006Q2	13.62485	15.143039	16.66123
2006Q3	3.448361	4.9521578	6.455954
2006Q4	17.24014	18.74014	20.24015
2007Q1	46.21848	47.702759	49.18704
2007Q2	13.29935	14.790702	16.28205
2007Q3	3.534074	5.0120428	6.490012
2007Q4	19.38771	20.861844	22.33598
2008Q1	45.2174	46.676239	48.13508
2008Q2	13.18606	14.649715	16.11337
2008Q3	3.679912	5.1310135	6.582115
2008Q4	21.25179	22.699019	24.14625
2009Q1	44.48372	45.916401	47.34909
2009Q2	13.15536	14.591371	16.02738
2009Q3	3.854232	5.2784208	6.70261
2009Q4	22.83283	24.253132	25.67344
2010Q1	43.90934	45.315992	46.72264
2010Q2	13.15861	14.567544	15.97647
2010Q3	4.026361	5.4241265	6.821892
2010Q4	24.1694	25.563314	26.95723
2011Q1	43.47512	44.856299	46.23747
2011Q2	13.19831	14.581037	15.96376
2011Q3	4.207047	5.5792023	6.951358
2011Q4	25.31114	26.679484	28.04783

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EnergyNorth Natural Gas Inc.
Residential Gas Use Per Customer Forecasting

Regression Model:	B2			
Dependent Variable:	USNR			
Independent Variable:	PRCG_1	PCI	CDDN	Auto(-4)

Size	84	Parameter:	4
Mean	23.3816	Std Dev	14.09718
R-Square	0.9944	DW	1.9878
SSE	36421.39	MSE	433.588

Term	PRCG_1	PCI	CDDN	Auto(-4)
Estimate	-20.0477	1.1484	0.1111	-0.819139
Std Error	17.5442	0.6569	0.006892	0.062584
T-Ratio	-1.14	1.75	16.12	-13.09
Pr>[t]	0.2564	0.0841	<.0001	

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	47.31945	48.8231	50.32675
2006Q2	13.50867	15.02239	16.53612
2006Q3	3.390562	4.890042	6.389522
2006Q4	17.20183	18.69771	20.19359
2007Q1	45.88745	47.36767	48.8479
2007Q2	13.15564	14.6424	16.12915
2007Q3	3.460455	4.933986	6.407517
2007Q4	19.33426	20.80415	22.27404
2008Q1	44.78536	46.24001	47.69466
2008Q2	12.98877	14.4476	15.90644
2008Q3	3.559831	5.006291	6.452751
2008Q4	21.14133	22.58415	24.02697
2009Q1	43.94622	45.37455	46.80287
2009Q2	12.89488	14.32582	15.75675
2009Q3	3.686523	5.105838	6.525154
2009Q4	22.66413	24.07982	25.49552
2010Q1	43.2903	44.69238	46.09445
2010Q2	12.84212	14.24572	15.64933
2010Q3	3.804666	5.197328	6.589989
2010Q4	23.92057	25.30968	26.69879
2011Q1	42.76655	44.14293	45.51931
2011Q2	12.81371	14.19086	15.56801
2011Q3	3.920657	5.287473	6.654289
2011Q4	24.97329	26.33664	27.69998

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Residential Gas Use Per Customer Forecasting

ARIMA Model (0,1,2)
Time Series: USNR

Size	85	Parameters	3		
Mean	23.07367	Std Dev	14.56763		
R-Square	0.985375	DW	1.922783		
SSE	25081.69	MSE	305.8743	RMSE	17.48926
Estimation					
Parameter	MU	MA1_1	MA1_2		
Estimate	-0.795273	0.365959	-0.303824		
Standard Error	1.7307	0.13731	0.136645		
t Value	-0.459509	2.665207	-2.22346		
FACTOR	0	1	1		
Lag	0	17	20		

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	50.13358	51.68735	53.24111
2006Q2	12.83089	14.40092	15.97095
2006Q3	3.834074	5.389117	6.94416
2006Q4	13.6781	15.22694	16.77579
2007Q1	50.44688	51.98066	53.51443
2007Q2	11.71038	13.25963	14.80888
2007Q3	3.694458	5.230195	6.765931
2007Q4	13.91787	15.4477	16.97753
2008Q1	51.91284	53.42824	54.94365
2008Q2	12.23814	13.77068	15.30322
2008Q3	4.395847	5.915191	7.434534
2008Q4	12.91721	14.42999	15.94276
2009Q1	51.77492	53.27445	54.77399
2009Q2	12.24712	13.76207	15.27703
2009Q3	4.9235	6.425874	7.928247
2009Q4	12.71309	14.20856	15.70402
2010Q1	51.65238	53.13533	54.61828
2010Q2	11.90242	13.39934	14.89626
2010Q3	4.704538	6.189638	7.674737
2010Q4	12.45531	13.93392	15.41253
2011Q1	51.58902	53.05581	54.52259
2011Q2	11.84022	13.31981	14.7994
2011Q3	4.641785	6.11011	7.578436
2011Q4	12.39231	13.85439	15.31648

APPENDIX A

KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Gas Use Per Customer Forecasting

Winters Exponential Smoothing Model
Var: USNR

Size	84	Parameter:	5		
Mean	23.07367	Std Dev	14.56763		
R-Square	0.967208	DW	2.31736		
SSE	695.9008	MSE	26.37993	RMSE	5.13614

	Constant	Linear	Quarter1	Quarter2	Quarter3	Quarter4
Estimate	26.37993	215.4984	260.0458	-64.49231	-169.9895	-25.564
Weight	0.2	0.2	0.25	0.25	0.25	0.25

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	46.81059	48.27548	49.74037
2006Q2	14.34829	15.82562	17.30295
2006Q3	3.693185	5.155618	6.618051
2006Q4	17.57704	19.03472	20.49239
2007Q1	46.65012	48.09218	49.53425
2007Q2	14.18927	15.64233	17.09538
2007Q3	3.533227	4.972324	6.411421
2007Q4	17.4167	18.85142	20.28615
2008Q1	46.48885	47.90889	49.32893
2008Q2	14.02924	15.45903	16.88882
2008Q3	3.372344	4.78903	6.205715
2008Q4	17.25547	18.66813	20.08079
2009Q1	46.32678	47.7256	49.12441
2009Q2	13.86824	15.27574	16.68324
2009Q3	3.210566	4.605735	6.000904
2009Q4	17.09337	18.48483	19.8763
2010Q1	46.16392	47.5423	48.92068
2010Q2	13.70631	15.09244	16.47858
2010Q3	3.04793	4.422441	5.796952
2010Q4	16.93045	18.30154	19.67263
2011Q1	46.00029	47.35901	48.71772
2011Q2	13.54349	14.90915	16.27481
2011Q3	2.884471	4.239146	5.593822
2011Q4	16.76673	18.11825	19.46976

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Gas Consumption Forecasting (Dth) (2006 -- 2010)

Model Var		C1	C2	ARIMA	Weighted Res Sales	Calculated Sales	Combined (50/50)
	Dependent	GSNR	GSNR	GSNR			
	Independent	GSP Auto(-4)	PRCG GSP Auto(-4)				
Weight		30.00%	30.00%	40.00%	100.00%		
	Residential Gas Sales Forecast -- Percent Growth from Base Year (2005)						
	2006Q4-2007Q3	2.57%	2.86%	0.80%	1.96%	2.80%	2.37%
	2007Q4-2008Q3	2.65%	2.91%	3.65%	3.12%	3.08%	3.10%
	2008Q4-2009Q3	3.02%	3.23%	3.07%	3.10%	2.21%	2.66%
	2009Q4-2010Q3	2.86%	3.00%	0.69%	2.05%	2.04%	2.05%
	2010Q4-2011Q3	2.79%	2.88%	1.56%	2.34%	2.14%	2.24%
	Average	2.78%	2.98%	1.95%	2.51%	2.45%	2.48%
	Residential Gas Sales Forecast (Dth) (Annual)						
	2005Q4-2006Q3	**6,440,173**	**6,373,218**	**6,267,804**	**6,351,139**	**6,190,483**	**6,270,811**
	2006Q4-2007Q3	6,605,996	6,555,369	6,318,014	6,475,615	6,363,654	6,419,635
	2007Q4-2008Q3	6,780,906	6,745,872	6,548,691	6,677,510	6,559,457	6,618,483
	2008Q4-2009Q3	6,985,470	6,963,457	6,749,937	6,884,653	6,704,409	6,794,531
	2009Q4-2010Q3	7,185,317	7,172,667	6,796,495	7,025,993	6,841,297	6,933,645
	2010Q4-2011Q3	7,385,507	7,379,427	6,902,273	7,190,389	6,987,414	7,088,902
	Average	6,897,228	6,865,002	6,597,202	6,767,550	6,607,786	6,687,668
	Residential Gas Sales Forecast (Dth) (Quarterly)						
	2005Q1	**3,528,270**	**3,528,270**	**3,528,270**	**3,528,270**	3,656,773	3,592,521
	2005Q2	**1,160,112**	**1,160,112**	**1,160,112**	**1,160,112**	1,152,706	1,156,409
	2005Q3	**408,202**	**408,202**	**408,202**	**408,202**	396,872	402,537
	2005Q4	**1,166,664**	**1,166,664**	**1,166,664**	**1,166,664**	1,117,630	1,142,147
	2006Q1	3,559,793	3,558,606	3,590,859	3,571,863	3,599,159	3,585,511
	2006Q2	1,258,946	1,214,090	1,076,523	1,172,520	1,097,882	1,135,201
	2006Q3	454,771	433,858	433,758	440,092	375,812	407,952
	2006Q4	1,196,674	1,194,043	1,163,577	1,182,646	1,289,845	1,236,246
	2007Q1	3,579,722	3,600,875	3,652,102	3,615,020	3,608,859	3,611,939
	2007Q2	1,340,108	1,283,348	1,058,275	1,210,347	1,085,920	1,148,134
	2007Q3	489,491	477,104	444,060	467,602	379,030	423,316
	2007Q4	1,214,658	1,204,545	1,206,344	1,208,299	1,414,044	1,311,171
	2008Q1	3,600,796	3,645,295	3,774,692	3,683,704	3,645,106	3,664,405
	2008Q2	1,429,259	1,365,667	1,054,872	1,260,427	1,102,754	1,181,590
	2008Q3	536,193	530,364	512,783	525,080	397,553	461,317
	2008Q4	1,243,818	1,225,694	1,178,654	1,212,315	1,506,041	1,359,178
	2009Q1	3,630,725	3,698,181	3,865,989	3,745,067	3,668,355	3,706,711
	2009Q2	1,523,717	1,452,855	1,131,908	1,345,735	1,115,229	1,230,482
	2009Q3	587,211	586,727	573,386	581,536	414,784	498,160
	2009Q4	1,273,658	1,246,673	1,197,762	1,235,204	1,601,358	1,418,281
	2010Q1	3,659,009	3,748,018	3,863,514	3,767,514	3,695,129	3,731,321
	2010Q2	1,615,496	1,537,093	1,142,776	1,402,887	1,124,005	1,263,446
	2010Q3	637,154	640,884	592,443	620,389	420,805	520,597
	2010Q4	1,302,582	1,265,905	1,215,450	1,256,726	1,685,064	1,470,895
	2011Q1	3,687,643	3,797,116	3,892,877	3,802,579	3,734,352	3,768,466
	2011Q2	1,706,712	1,620,754	1,172,139	1,467,095	1,138,337	1,302,716
	2011Q3	688,571	695,652	621,807	663,989	429,660	546,825
	2011Q4	1,332,195	1,285,233	1,244,813	1,283,154	1,764,365	1,523,759

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Gas Consumption (Dth) Forecasting

Regression Model:	C1b				
Dependent Variable:	GSNR				
Independent Variable:	GSP	Auot(-1)	Auot(-2)	Auot(-3)	Auot(-4)

Size	84	Parameters	5
Mean	1317481	Std Dev	872900
R-Square	0.9939	DW	0.935
SSE	1.35E+14	MSE	1.61E+12

Term	GSP	Auot(-1)	Auot(-2)	Auot(-3)	Auot(-4)
Estimate	152.1634	-0.0171	5.96E-03	0.003858	-9.89E-01
Std Error	6.71E+01	1.95E-02	1.79E-02	1.97E-02	1.90E-02
T-Ratio	2.27	-0.88	0.33	0.2	-51.97
Pr>[t]	0.0259	0.3828	0.7403	0.8454	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	2750675	3559793	4368910
2006Q2	1167627	1258946	1350264
2006Q3	364470	454771.1	545072.1
2006Q4	1106879	1196674	1286470
2007Q1	3490899	3579722	3668546
2007Q2	1249064	1340108	1431153
2007Q3	399420.4	489490.8	579561.2
2007Q4	1125110	1214658	1304206
2008Q1	3512177	3600796	3689415
2008Q2	1338608	1429259	1519910
2008Q3	446467.9	536192.6	625917.3
2008Q4	1154636	1243818	1333000
2009Q1	3542433	3630725	3719016
2009Q2	1433534	1523717	1613899
2009Q3	497903.7	587210.6	676517.4
2009Q4	1184911	1273658	1362406
2010Q1	3571115	3659009	3746904
2010Q2	1525839	1615496	1705153
2010Q3	548320.1	637153.6	725987.1
2010Q4	1214316	1302582	1390847
2011Q1	3600196	3687643	3775090
2011Q2	1617615	1706712	1795809
2011Q3	600244.9	688570.6	776896.3
2011Q4	1244443	1332195	1419947

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Gas Consumption (Dth) Forecasting

Regression Model:	C2c					
Dependent Variable:	GSNR					
Independent Variable:	PRCG_1	GSP	Auot(-1)	Auot(-2)	Auot(-3)	Auot(-4)

Size	81	Parameters	7
Mean	1317481.5	Std Dev	872900.04
R-Square	0.9813	DW	1.7866
SSE	1.25E+14	MSE	1.54E+12

Term	Intercept	PRCG_1	GSP	Auot(-1)	Auot(-2)	Auot(-3)	Auot(-4)
Estimate	8469003	-1117401	156.4301	0.0596	0.0692	0.0795	-0.9301
Std Error	1.60E+06	1.03E+06	4.33E+01	5.61E-03	2.11E-03	1.04E-02	2.71E-03
T-Ratio	5.31	-1.09	3.61	10.63	32.76	7.67	-343.06
Pr>[t]	<.0001	0.2796	0.0005	<.0001	<.0001	<.0001	<.0001

Forecasts (from Base Period 2005-Q4)

Date	LCL	Forecast	UCL
2006Q1	3251848.49	3558605.89	3865363.3
2006Q2	1123306.22	1214089.95	1304873.7
2006Q3	344076.987	433857.635	523638.28
2006Q4	1104715.49	1194042.71	1283369.9
2007Q1	3512511.48	3600874.89	3689238.3
2007Q2	1192728.67	1283347.93	1373967.2
2007Q3	387450.464	477103.741	566757.02
2007Q4	1115378.72	1204544.89	1293711.1
2008Q1	3557050.86	3645295.19	3733539.5
2008Q2	1275297.49	1365667.31	1456037.1
2008Q3	440921.216	530364.144	619807.07
2008Q4	1136771.27	1225694	1314616.7
2009Q1	3610141.7	3698180.55	3786219.4
2009Q2	1362785.01	1452855.31	1542925.6
2009Q3	497541.284	586726.773	675912.26
2009Q4	1158033.33	1246672.69	1335312
2010Q1	3660226.42	3748017.64	3835808.9
2010Q2	1447361.88	1537092.73	1626823.6
2010Q3	551994.157	640884.001	729773.85
2010Q4	1177577.42	1265904.86	1354232.3
2011Q1	3709603	3797116.08	3884629.1
2011Q2	1531386.05	1620754.2	1710122.3
2011Q3	607080.588	695652.217	784223.85
2011Q4	1197234.78	1285233.23	1373231.7

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KeySpan Energy Delivery New England
EnergyNorth Natural Gas Inc.
Residential Gas Consumption (Dth) Forecasting

ARIMA Model (0,1,2)
Time Series: GSNR

Size	85	Parameters	3		
Mean	1317481.496	Std Dev	872900.0386		
R-Square	0.987879378	DW	1.320508125		
SSE	1.10962E+14	MSE	1.3532E+12	RMSE	1163271.1

Estimation			
Parameter	MU	MA1_1	MA1_2
Estimate	293631.8719	0.3441897	-0.259873623
Standard Error	113903.1465	0.1386313	0.137639482
t Value	2.577908345	2.4827701	-1.888074693
FACTOR	0	1	1
Lag	0	17	20

Forecasts (from Base Period 2005-Q4)

Date	L95	Forecast	U95
2006Q1	3362861.849	3590858.8	3818855.738
2006Q2	981826.8792	1076523.1	1171219.257
2006Q3	340083.9819	433758.08	527432.1735
2006Q4	1070456.503	1163577.4	1256698.356
2007Q1	3559987.139	3652102.2	3744217.342
2007Q2	963848.0616	1058274.9	1152701.698
2007Q3	350600.9659	444059.67	537518.3833
2007Q4	1113430.661	1206344.4	1299258.2
2008Q1	3682744.882	3774692.3	3866639.75
2008Q2	960540.0247	1054871.6	1149203.267
2008Q3	419375.7474	512782.94	606190.1337
2008Q4	1085837.462	1178654.5	1271471.529
2009Q1	3774092.862	3865988.6	3957884.334
2009Q2	1037647.178	1131907.7	1226168.216
2009Q3	480030.2256	573385.79	666741.362
2009Q4	1105023.618	1197762.4	1290501.156
2010Q1	3771661.224	3863513.9	3955366.605
2010Q2	1048802.51	1142775.6	1236748.782
2010Q3	499338.5152	592443.36	685548.2126
2010Q4	1122950.685	1215450.2	1307949.659
2011Q1	3801229.377	3892877.1	3984524.826
2011Q2	1078509.428	1172138.8	1265768.239
2011Q3	529014.3185	621806.55	714598.7837
2011Q4	1152620.821	1244813.4	1337005.897

KeySpan Energy Delivery New England - EnergyNorth Gas Inc.
Demand Forecast Econometric Model
Variable List
(2005)

Index	Variable Name	Unit	Description	Source	Period Covered	End of History Date
Dependent Variables						
1	CUSN		Number of Non-Heating Residential Customers	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
2	CUSH		Number of Heating Residential Customers	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
3	CUSR		Number of Residential Customers	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
4	CUSI		Number of Industrial Customers	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
5	CUSC		Number of Commercial Customers	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
6	CUSCI		Number of Commercial and Industrial Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
7	USEN	MMBTU/Customer	Gas Consumption per Non-Heating Res. Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
8	USEH	MMBTU/Customer	Gas Consumption per Heating Res. Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
9	USER	MMBTU/Customer	Gas Consumption per Residential Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
10	USEC	MMBTU/Customer	Gas Consumption per Commercial Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
11	USEI	MMBTU/Customer	Gas Consumption per Industrial Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
12	USECI	MMBTU/Customer	Gas Consumption per C & I Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
13	USNN	MMBTU/Customer	Gas Consumption per Non-Heating Res. Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
14	USNH	MMBTU/Customer	Gas Consumption per Heating Res. Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
15	USNR	MMBTU/Customer	Gas Consumption per Residential Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
16	USNC	MMBTU/Customer	Gas Consumption per Commercial Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
17	USNI	MMBTU/Customer	Gas Consumption per Industrial Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
18	USNCI	MMBTU/Customer	Gas Consumption per C & I Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
19	GASN	MMBTU	Gas Consumption of Residential Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
20	GASH	MMBTU	Gas Consumption of Heating Res. Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
21	GASR	MMBTU	Gas Consumption of Non-Heating Res. Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
22	GASC	MMBTU	Gas Consumption of C & I Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
23	GASI	MMBTU	Gas Consumption of Commercial Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
24	GASCI	MMBTU	Gas Consumption of Industrial Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
25	GSNN	MMBTU	Normal Gas Consumption of Residential Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
26	GSNH	MMBTU	Normal Gas Consumption of Heating Res. Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
27	GSNR	MMBTU	Normal Gas Cons. of Non-Heating Res.Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
28	GSNC	MMBTU	Normal Gas Consumption of C&I Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
29	GSNI	MMBTU	Normal Gas Consumption of Commercial Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
30	GSNCI	MMBTU	Normal Gas Consumption of Industrial Cust.	EnergyNorth Historical Records	1984Q1-2005Q4	2005 Q4
Independent Variables						
31	CPI	1982-84 = 100	Consumer Price Index	Global Insight	1984Q1-2020Q4	2005 Q4
32	GSP	Millions of $	Gross State Product--Aggregate	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4	2004 Q4
33	RGSP	Millions of 2000 $	Real Gross State Product--Aggregate	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4	2004 Q4
34	POP	Thousands	Total Population	Bureau of Census, Current Population Reports	1984Q1-2020Q4	2005 Q2
35	NMIG	Thousands	Net Migration	Bureau of Census, Current Population Reports	1984Q1-2020Q4	2005 Q2
36	EMP	Thousands	Employment, Total Non-Agriculture	Bureau of Labor Statistics	1984Q1-2020Q4	2005 Q4
37	RUEM	Percent	Unemployment Rate	Bureau of Labor Statistics	1984Q1-2020Q4	2005 Q4
38	UEMP	Thousands	Number Unemployed	Bureau of Labor Statistics	1984Q1-2020Q4	2005 Q4
39	REMP	Thousands	Resident Employment	Bureau of Labor Statistics	1984Q1-2020Q4	2005 Q4
40	LBFC	Thousands	Total Labor Force	Bureau of Labor Statistics	1984Q1-2020Q4	2005 Q4
41	HH	Thousands	Households, Family and Non-Family	Global Insight	1984Q1-2020Q4	2000 Q1
42	HSTM	Thousands	Housing Starts, Private Multi-Family	Global Insight	1984Q1-2020Q4	2005 Q4
43	HSTS	Thousands	Housing Starts, Private Single Family	Global Insight	1984Q1-2020Q4	2005 Q4
44	HSTT	Thousands	Housing Starts, Total Private	Global Insight	1984Q1-2020Q4	2005 Q4
45	HSOLD	Thousands	Home Sales, Existing Single-family units	Global Insight	1984Q1-2020Q4	2005 Q4
46	HINC	Thousands of $	Average Household Income	Global Insight	1984Q1-2020Q4	2000 Q1
47	PCI	Thousands of $	Per Capita Personal Income	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4	2005 Q4
48	RPCI	Thousands 2000 $	Real Per Capita Personal Income	Bureau of Economic Analysis	1984Q1-2020Q4	2005 Q4
49	PINC	Millions of $	Personal Income, Total, By Place of Residence	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4	2005 Q4
50	RPINC	Millions of 2000 $	Real Personal Income, Total	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4	2005 Q4
51	RPIR	Millions of 2000 $	Real Income, Residence Adjustment	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4	2005 Q4
52	RPTR	Millions of 2000 $	Real Nonfarm Proprietors Income	Bureau of Economic Analysis	1984Q1-2020Q4	2005 Q4
53	PITP	Millions of $	Personal Income, Total Proprietors Income,	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4	2005 Q4
54	TPTR	Millions of 2000 $	Real Total Proprietors Income	Bureau of Economic Analysis, Global Insight	1984Q1-2020Q4	2005 Q4
55	PINF	Millions of $	Personal Income, Nonfarm Proprietors Income	Bureau of Economic Analysis	1984Q1-2020Q4	2005 Q4
56	INDX	(2002=100)	Industrial Production Index, Total	Global Insigh	1984Q1-2020Q4	2005 Q4
57	PRCO	($/MCF)	New Hampshire #2 Heating Oil Production Price	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
58	PRCG	($/MCF)	New Hampshire Natual Gas City Gate Price	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
59	PRCR	($/MCF)	New Hampshire Residential Natural Gas Price	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
60	PRCC	($/MCF)	New Hampshire Commercial Natural Gas Price	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
61	PRCI	($/MCF)	New Hampshire Industrial Natural Gas Price	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
62	PRCCI	($/MCF)	New Hampshire C & I Natural Gas Price	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
63	EGYO	(MMCF)	New Hampshire #2 Heating Oil cnsmp	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
64	EGYG	(MMCF)	New Hampshire Natural Gas cnsmp by All	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
65	EGYR	(MMCF)	New Hampshire Residential Natural Gas cnsmp	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
66	EGYC	(MMCF)	New Hampshire Commercial Natural Gas cnsmp	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
67	EGYI	(MMCF)	New Hampshire Industrial Natural Gas cnsmp	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
68	RPRR	PRCR/PRCO	Price Ratio: Res. Natural Gas Price : #2 Oil Price	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
69	RPRC	PRCC/PRCO	Price Ratio: Commercial Gas Price : #2 Oil Price	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
70	RPRI	PRCI/PRCO	Price Ratio: Industrial Gas Price : #2 Oil Price	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
71	REGR	EGYR/EGYO	Energy Use Ratio: Res. Natural Gas : #2 Oil	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
72	REGC	EGYC/EGYO	Energy Use Ratio: Commercial Gas : #2 Oil	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
73	REGI	EGYI/EGYO	Energy Use Ratio: Industrial Gas : #2 Oil	U.S. Energy Information Administration	1984Q1-2005Q4	2005 Q4
74	REVN	($)	Revenue to Residential Non-Heating Customers	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
75	REVH	($)	Revenue to Residential Heating Customers	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
76	REVR	($)	Revenue to Residential Customers	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
77	REVC	($)	Revenue to Commercial Customers	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
78	REVI	($)	Revenue to Industrial Customers	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
79	REVCI	($)	Revenue to Commercial and Industrial Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
80	RVNN	($)	Revenue (Normal)to Residential Non-Heating Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
81	RVNH	($)	Revenue (Normal)to Residential Heating Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
82	RVNR	($)	Revenue (Normal)to Residential Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
83	RVNC	($)	Revenue (Normal)to Commercial Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
84	RVNI	($)	Revenue (Normal)to Industrial Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
85	RVNCI	($)	Revenue (Normal)to C & I Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4

KeySpan Energy Delivery New England - EnergyNorth Gas Inc.
Demand Forecast Econometric Model
Variable List
(2005)

Index	Variable Name	Unit	Description	Source	Period Covered	End of History Date
86	CHGN	($/MMBTU)	Company Charge to Residential Non-Heating Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
87	CHGH	($/MMBTU)	Company Charge to Residential Heating Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
88	CHGR	($/MMBTU)	Company Charge to Residential Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
89	CHGC	($/MMBTU)	Company Charge to Commercial Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
90	CHGI	($/MMBTU)	Company Charge to Industrial Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
91	CHGCI	($/MMBTU)	Company Charge to C & I Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
92	CHNN	($/MMBTU)	Company charge (Normal)to Res. Non-Heating Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
93	CHNH	($/MMBTU)	Company charge (Normal)to Res. Heating Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
94	CHNR	($/MMBTU)	Company charge (Normal)to Residential Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
95	CHNC	($/MMBTU)	Company charge (Normal)to Commercial Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
96	CHNI	($/MMBTU)	Company charge (Normal)to Industrial Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
97	CHNCI	($/MMBTU)	Company charge (Normal)to C & I Cust.	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
98	CDDN		Normal Callendar Degree Days	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
99	CDDA		Actual Callendar Degree Days	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
100	BDDN		Normal Billing Degree Days	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4
101	BDDA		Actual Billing Degree Days	EnergyNorth Billing Frequncy Record	1984Q1-2005Q4	2005 Q4

Res Var Index	1	2	3	4	5	6	7	8	9
Res Var Name	CUSN	CUSH	CUSR	USEN	USEH	USER	USNN	USNH	USNR
Description	ENGI: Number of Non-Heating Residential Customers	ENGI: Number of Heating Residential Customers	ENGI: Number of Residential Customers	ENGI: Natural Gas Consumption per Non-Heating Residential Customers	ENGI: Natural Gas Consumption per Heating Residential Customers	ENGI: Natural Gas Consumption per Residential Customers	ENGI: Natural Gas Consumption per Non-Heating Residential Customers	ENGI: Natural Gas Consumption per Heating Residential Customers	ENGI: Natural Gas Consumption per Residential Customers
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	5875	33173	39048	8.37	45.14	39.61	8.50	46.24	40.56
1984Q2	5830	33183	39013	5.96	20.46	18.29	5.82	19.59	17.53
1984Q3	5681	33085	38766	3.62	6.81	6.35	3.59	6.74	6.28
1984Q4	5966	33919	39885	5.12	22.77	20.13	5.29	24.63	21.74
1985Q1	5995	34915	40910	8.28	44.03	38.79	8.55	46.28	40.75
1985Q2	5949	35129	41078	6.03	17.70	16.01	6.20	18.64	16.84
1985Q3	5797	35163	40960	3.69	6.83	6.38	3.62	6.87	6.41
1985Q4	6088	36270	42358	5.02	22.94	20.36	5.06	23.38	20.75
1986Q1	6117	38608	44725	8.73	44.19	39.34	9.00	46.03	40.97
1986Q2	6070	39015	45085	6.52	17.86	16.33	6.98	19.67	17.96
1986Q3	5915	39453	45368	3.14	6.12	5.73	3.13	6.05	5.67
1986Q4	6212	40791	47003	4.81	24.90	22.24	4.79	24.71	22.08
1987Q1	6242	42210	48452	8.72	49.92	44.61	8.97	52.01	46.47
1987Q2	6194	42852	49046	6.43	22.21	20.22	6.66	23.53	21.40
1987Q3	6036	42639	48675	4.12	8.13	7.64	4.18	8.24	7.74
1987Q4	6339	43756	50095	5.48	25.26	22.76	5.50	25.48	22.95
1988Q1	6370	45173	51543	7.83	49.66	44.49	7.94	50.82	45.52
1988Q2	6320	45218	51538	6.74	22.51	20.57	6.81	22.85	20.88
1988Q3	6159	44672	50831	3.60	7.40	6.94	3.58	7.32	6.87
1988Q4	6468	45376	51844	5.08	27.39	24.60	5.07	27.17	24.42
1989Q1	6500	46909	53409	8.60	49.62	44.63	8.89	52.27	46.99
1989Q2	6449	47004	53453	6.88	22.28	20.42	6.93	21.97	20.15
1989Q3	6285	45897	52182	3.66	7.53	7.07	3.69	7.67	7.19
1989Q4	6600	46503	53103	6.39	27.46	24.84	6.22	25.77	23.34
1990Q1	6632	47867	54499	8.00	47.37	42.58	8.24	49.85	44.79
1990Q2	6581	47476	54057	5.93	22.00	20.04	5.92	22.16	20.18
1990Q3	6413	46199	52612	4.10	7.08	6.72	4.06	7.09	6.72
1990Q4	6387	47332	53719	5.91	22.15	20.22	6.26	25.06	22.82
1991Q1	6304	48797	55101	8.35	43.74	39.69	8.82	47.55	43.12
1991Q2	6196	48311	54507	5.82	18.82	17.35	6.32	21.44	19.72
1991Q3	6049	47103	53152	3.99	6.72	6.41	3.92	6.64	6.33
1991Q4	6017	48172	54190	5.80	22.53	20.67	5.98	24.04	22.03
1992Q1	6025	49426	55451	8.51	47.94	43.66	8.73	49.85	45.38
1992Q2	6035	49138	55173	6.23	23.17	21.32	6.06	21.78	20.06
1992Q3	5975	47926	53901	4.21	7.02	6.71	4.21	7.02	6.71
1992Q4	6027	49069	55096	6.13	24.59	22.57	6.04	23.85	21.90
1993Q1	5998	49743	55741	8.06	49.90	45.40	8.03	49.15	44.73
1993Q2	6006	49717	55723	6.05	21.31	19.67	6.09	21.54	19.88
1993Q3	6006	48841	54847	4.01	6.44	6.18	3.79	6.00	5.76
1993Q4	6041	50009	56050	5.70	23.90	21.94	5.67	23.50	21.58
1994Q1	6070	50949	57019	8.27	52.77	48.03	7.88	48.55	44.22
1994Q2	6065	50957	57022	5.85	20.91	19.31	5.83	20.79	19.20
1994Q3	6035	50125	56160	3.96	6.23	5.99	4.12	6.36	6.12
1994Q4	6071	51184	57256	5.20	27.67	25.29	5.40	30.90	28.19
1995Q1	5933	52218	58151	6.60	44.63	40.75	6.94	48.94	44.65
1995Q2	5852	52220	58072	5.39	20.03	18.55	5.38	19.67	18.23
1995Q3	5794	51357	57151	4.07	6.68	6.42	3.94	6.47	6.21
1995Q4	5817	52277	58094	4.86	25.18	23.15	4.84	24.60	22.62
1996Q1	5870	53009	58879	6.32	49.61	45.29	6.31	49.36	45.07
1996Q2	5872	53113	58985	5.42	20.77	19.24	5.32	19.65	18.22
1996Q3	5854	52552	58406	4.14	6.87	6.60	4.10	6.85	6.57
1996Q4	5820	53417	59237	4.92	25.40	23.39	4.89	24.99	23.01
1997Q1	5864	54151	60016	6.08	44.52	40.76	6.23	47.75	43.69
1997Q2	5895	54260	60155	5.33	22.06	20.42	5.17	20.00	18.54
1997Q3	5886	54050	59935	4.19	6.55	6.32	4.14	6.46	6.23
1997Q4	5908	54775	60683	5.00	24.85	22.92	4.99	24.70	22.78
1998Q1	5927	55334	61261	6.20	42.07	38.60	6.58	48.29	44.26
1998Q2	5964	55610	61574	5.23	17.66	16.46	5.48	19.58	18.22
1998Q3	5947	55349	61296	3.86	6.50	6.25	3.55	6.15	5.90
1998Q4	5959	56091	62050	4.80	20.30	18.81	4.89	21.77	20.15
1999Q1	5903	56757	62660	6.07	45.10	41.43	6.25	47.72	43.81
1999Q2	5864	57002	62866	5.02	17.57	16.40	5.14	18.18	16.96
1999Q3	5870	57025	62895	3.48	5.87	5.65	3.55	6.04	5.81
1999Q4	5865	57932	63797	4.75	20.43	18.98	4.88	21.85	20.29
2000Q1	5782	58480	64262	6.41	47.38	43.69	6.51	48.71	44.92
2000Q2	5781	58784	64566	5.09	18.28	17.10	5.12	18.94	17.70
2000Q3	5663	57686	63349	3.91	6.57	6.33	3.87	6.47	6.24
2000Q4	5836	58047	63883	5.54	24.31	22.60	5.51	24.02	22.33
2001Q1	5716	58722	64437	7.18	48.21	44.57	7.09	47.16	43.60
2001Q2	5772	58585	64356	5.54	19.42	18.17	5.62	19.48	18.24
2001Q3	5741	59179	64920	3.59	5.95	5.74	3.48	5.90	5.69
2001Q4	6027	59330	65357	5.67	18.52	17.33	6.13	21.22	19.82
2002Q1	5987	59932	65919	8.15	41.05	38.06	8.88	47.16	43.68
2002Q2	5963	59858	65821	5.71	19.69	18.42	5.72	19.94	18.66
2002Q3	5852	58878	64730	3.95	6.85	6.59	3.32	6.11	5.86
2002Q4	5804	60189	65993	6.28	24.85	23.22	6.18	24.30	22.70
2003Q1	5787	62172	67959	9.58	51.84	48.24	10.00	55.09	51.25
2003Q2	5947	63268	69215	6.20	20.75	19.50	5.80	18.04	16.99
2003Q3	6016	64590	70606	3.48	5.89	5.69	3.48	5.88	5.68
2003Q4	5548	61697	67245	6.04	23.12	21.71	5.51	19.13	18.00
2004Q1	5771	65629	71400	9.18	48.82	45.61	9.97	54.98	51.34

Res Var Index	1	2	3	4	5	6	7	8	9
Res Var Name	CUSN	CUSH	CUSR	USEN	USEH	USER	USNN	USNH	USNR
Description	ENGI: Number of Non-Heating Residential Customers	ENGI: Number of Heating Residential Customers	ENGI: Number of Residential Customers	ENGI: Natural Gas Consumption per Non-Heating Residential Customers	ENGI: Natural Gas Consumption per Heating Residential Customers	ENGI: Natural Gas Consumption per Residential Customers	ENGI: Natural Gas Consumption per Non-Heating Residential Customers	ENGI: Natural Gas Consumption per Heating Residential Customers	ENGI: Natural Gas Consumption per Residential Customers
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	5585	64293	69878	5.84	18.38	17.37	5.70	17.33	16.40
2004Q3	5675	66341	72016	3.68	5.92	5.74	3.67	5.90	5.73
2004Q4	5275	62637	67911	5.71	20.94	19.75	5.27	17.78	16.81
2005Q1	5403	66205	71607	9.02	46.66	43.82	9.78	52.50	49.27
2005Q2	5384	66191	71575	5.79	18.88	17.90	5.50	17.08	16.21
2005Q3	5423	67908	73331	3.54	5.72	5.56	3.54	5.73	5.57
2005Q4	5076	64411	69487	5.78	20.84	19.74	5.36	17.69	16.79
2006Q1									
2006Q2									
2006Q3									
2006Q4									
2007Q1									
2007Q2									
2007Q3									
2007Q4									
2008Q1									
2008Q2									
2008Q3									
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2018Q3									
2018Q4									
2019Q1									
2019Q2									
2019Q3									
2019Q4									
2020Q1									
2020Q2									
2020Q3									
2020Q4									

Res Var Index	10	11	12	13	14	15	16	17	18
Res Var Name	GASN	GASH	GASR	GSNN	GSNH	GSNR	CPI	GSP	RGSP
Description	ENGI: Natural Gas Consumption of Residential Customers	ENGI: Natural Gas Consumption of Heating Residential Customers	ENGI: Natural Gas Consumption of Non-Heating Residential Customers	ENGI: Normal Natural Gas Consumption of Residential Customers	ENGI: Normal Natural Gas Consumption of Heating Residential Customers	ENGI: Normal Natural Gas Consumption of Non-Heating Residential Customers	Consumer Price Index	Gross State Product– Aggregate	Real Gross State Product– Aggregate
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	49173	1497415	1546588	49942	1533918	1583860	102.4745	13921.42	0.00
1984Q2	34729	678879	713608	33947	650016	683963	102.8074	14488.95	0.00
1984Q3	20568	225412	245980	20386	223103	243489	103.8268	14945.54	0.00
1984Q4	30563	772226	802788	31582	835581	867162	104.6483	15355.14	0.00
1985Q1	49623	1537329	1586952	51271	1615897	1667168	106.6530	15862.32	0.00
1985Q2	35876	621916	657793	36897	654816	691713	108.1891	16297.67	0.00
1985Q3	21400	240048	261448	20960	241516	262476	108.6814	16826.34	0.00
1985Q4	30560	831927	862488	30780	847980	878760	111.5703	17266.39	0.00
1986Q1	53399	1706040	1759439	55070	1777286	1832356	110.2958	17768.96	0.00
1986Q2	39589	696736	736325	42343	767319	809663	110.3331	18166.74	0.00
1986Q3	18587	241441	260027	18501	238641	257142	110.1529	18679.03	0.00
1986Q4	29871	1015671	1045541	29751	1007913	1037665	112.1824	19124.66	0.00
1987Q1	54461	2107159	2161620	55964	2195430	2251394	113.3266	19950.39	0.00
1987Q2	39848	951845	991692	41253	1008144	1049397	114.8597	20665.86	0.00
1987Q3	24875	346771	371646	25253	351373	376626	115.6120	21389.43	0.00
1987Q4	34726	1105432	1140158	34881	1115041	1149922	119.0104	22299.88	0.00
1988Q1	49890	2243132	2293023	50581	2295688	2346268	120.4813	21929.23	0.00
1988Q2	42579	1017753	1060332	43037	1033089	1076126	123.1453	22384.90	0.00
1988Q3	22195	330570	352765	22043	327003	349046	126.0685	22720.70	0.00
1988Q4	32833	1242737	1275570	32824	1233085	1265909	127.4170	23159.34	0.00
1989Q1	55874	2327734	2383608	57807	2451780	2509586	130.2364	23269.59	0.00
1989Q2	44387	1047189	1091577	44676	1032576	1077251	132.7346	23470.38	0.00
1989Q3	23026	345833	368859	23166	351832	374999	133.9616	23632.57	0.00
1989Q4	42194	1277111	1319305	41063	1198567	1239630	137.8583	23688.24	0.00
1990Q1	53050	2267541	2320591	54670	2386368	2441039	140.0640	23656.06	26630.39
1990Q2	38993	1044374	1083366	38990	1051934	1090924	139.7930	23659.55	26368.37
1990Q3	26287	327307	353594	26035	327777	353812	144.3361	23543.96	26043.09
1990Q4	37766	1048445	1086211	39949	1186098	1226048	148.0301	23223.97	25524.58
1991Q1	52660	2134331	2186991	55583	2320122	2375705	150.5876	23965.03	26038.07
1991Q2	36085	909404	945489	39160	1035635	1074795	150.4335	24344.52	26272.06
1991Q3	24118	316422	340540	23719	312873	336592	151.6294	24704.17	26464.20
1991Q4	34920	1085283	1120203	35969	1158051	1194020	153.2984	25018.77	26654.04
1992Q1	51277	2369605	2420882	52589	2463929	2516519	154.3808	25603.19	27160.75
1992Q2	37618	1138643	1176261	36586	1070003	1106589	155.4624	26111.44	27558.88
1992Q3	25186	336276	361462	25152	336287	361439	157.8577	26604.95	27964.59
1992Q4	36929	1206605	1243534	36376	1170121	1206497	158.2196	27154.68	28407.33
1993Q1	48336	2482343	2530679	48182	2445068	2493251	160.6911	27139.14	28208.94
1993Q2	36308	1059525	1095833	36597	1071111	1107708	160.1714	27398.99	28339.71
1993Q3	24115	314724	338840	22779	292909	315687	160.6923	27630.37	28473.16
1993Q4	34412	1195418	1229829	34232	1175312	1209544	162.9581	28122.86	28844.20
1994Q1	50206	2688711	2738916	47841	2473729	2521570	163.4125	28674.11	29317.26
1994Q2	35481	1065555	1101036	35347	1059260	1094607	163.9126	29194.20	29766.03
1994Q3	23928	312501	336429	24861	318960	343821	166.0462	29568.52	29998.40
1994Q4	31578	1416502	1448080	32763	1581343	1614106	166.1299	30078.28	30414.97
1995Q1	39145	2330544	2369689	41163	2555482	2596645	167.8976	30993.61	31293.57
1995Q2	31531	1045766	1077296	31490	1026976	1058466	168.3523	31447.27	31720.02
1995Q3	23593	343035	366627	22835	332277	355112	169.4686	32135.41	32347.28
1995Q4	28298	1316533	1344831	28155	1285902	1314058	171.4913	32807.00	32950.78
1996Q1	37105	2629525	2666630	37035	2616670	2653706	173.4123	33289.26	33477.73
1996Q2	31839	1103088	1134927	31236	1043696	1074932	174.7597	34157.21	34385.26
1996Q3	24241	361234	385475	23995	359892	383886	175.1595	34749.62	35028.78
1996Q4	28606	1356976	1385581	28445	1334687	1363132	178.6147	35539.30	35791.40
1997Q1	35646	2410589	2446235	36527	2585637	2622165	179.6608	35727.37	35762.99
1997Q2	31439	1197131	1228570	30466	1084939	1115405	179.9009	36330.66	36401.55
1997Q3	24672	354180	378852	24379	349072	373450	180.6567	36911.49	36949.04
1997Q4	29521	1361406	1390927	29472	1352827	1382299	181.4077	37306.48	37314.42
1998Q1	36753	2327694	2364447	38992	2672353	2711345	183.5020	38110.50	38412.85
1998Q2	31201	982290	1013491	32682	1088950	1121632	184.4057	38569.93	39011.29
1998Q3	22962	359941	382903	21113	340626	361739	183.5080	39298.06	39801.89
1998Q4	28629	1138428	1167056	29127	1221328	1250455	185.8773	40173.52	40745.97
1999Q1	35821	2559942	2595763	36867	2708218	2745085	186.5375	39687.58	40198.40
1999Q2	29437	1001456	1030893	30162	1036126	1066289	188.2712	39929.80	40377.99
1999Q3	20437	334964	355401	20826	344416	365242	188.3838	40311.35	40697.59
1999Q4	27872	1183267	1211140	28619	1265595	1294214	192.1140	40979.27	41270.02
2000Q1	37083	2770666	2807749	37667	2848756	2886423	195.0051	42370.03	42496.59
2000Q2	29404	1074776	1104180	29593	1113351	1142944	196.2250	43480.92	43538.29
2000Q3	22169	378906	401075	21914	373346	395261	198.9644	43908.45	43855.41
2000Q4	32308	1411353	1443661	32143	1394525	1426668	201.2379	44564.59	44445.70
2001Q1	41024	2830887	2871912	40542	2769023	2809565	204.1178	44057.51	43706.81
2001Q2	31993	1137560	1169553	32454	1141216	1173670	206.0262	44439.53	43785.77
2001Q3	20588	352363	372950	19963	349179	369142	206.1879	44377.93	43577.22
2001Q4	34200	1098684	1132884	36974	1258696	1295670	206.7880	44689.03	43694.20
2002Q1	48798	2460212	2509010	53152	2826114	2879266	207.7972	45409.13	44126.53
2002Q2	34077	1178669	1212746	34111	1193782	1227894	208.9996	45887.07	44388.04
2002Q3	23137	403405	426542	19441	359883	379324	210.0053	46398.15	44670.85
2002Q4	36435	1495631	1532065	35870	1462387	1498257	213.5279	46745.66	44714.58
2003Q1	55469	3222796	3278265	57883	3424753	3482636	215.4818	47123.45	44991.97
2003Q2	36867	1312647	1349513	34479	1141331	1175810	216.6297	47656.52	45448.36
2003Q3	20913	380492	401405	20913	379920	400833	218.0900	48695.54	46299.44
2003Q4	33507	1426384	1459891	30595	1179985	1210580	221.2831	49320.49	46756.23
2004Q1	52957	3203771	3256728	57509	3608130	3665638	222.9654	50514.76	47505.08

Res Var Index	10	11	12	13	14	15	16	17	18
Res Var Name	GASN	GASH	GASR	GSNN	GSNH	GSNR	CPI	GSP	RGSP
Description	ENGI: Natural Gas Consumption of Residential Customers	ENGI: Natural Gas Consumption of Heating Residential Customers	ENGI: Natural Gas Consumption of Non-Heating Residential Customers	ENGI: Normal Natural Gas Consumption of Residential Customers	ENGI: Normal Natural Gas Consumption of Heating Residential Customers	ENGI: Normal Natural Gas Consumption of Non-Heating Residential Customers	Consumer Price Index	Gross State Product–Aggregate	Real Gross State Product–Aggregate
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	32608	1181517	1214124	31839	1114166	1146005	225.8373	51525.29	48053.73
2004Q3	20859	392477	413335	20854	391642	412497	225.0902	52286.95	48660.33
2004Q4	30104	1311378	1341482	27801	1113762	1141563	227.8726	53153.00	49190.69
2005Q1	48740	3089376	3138116	52856	3475414	3528270	229.1702	54039.51	49651.03
2005Q2	31153	1249895	1281048	29615	1130497	1160112	233.4505	54774.72	50023.85
2005Q3	19200	388400	407600	19196	389007	408202	236.8629	55720.46	50494.77
2005Q4	29337	1342515	1371852	27229	1139435	1166664	237.9245	56310.66	50616.27
2006Q1							239.3080	57628.09	51387.60
2006Q2							240.4924	58496.71	51893.18
2006Q3							240.9599	59177.66	52269.32
2006Q4							241.9080	59832.92	52592.77
2007Q1							242.9320	60473.02	52888.57
2007Q2							243.8489	61103.39	53245.86
2007Q3							244.9061	61789.96	53646.33
2007Q4							246.1188	62563.78	54094.72
2008Q1							247.4104	63411.33	54540.22
2008Q2							248.4899	64281.08	55051.28
2008Q3							249.6398	65124.93	55534.69
2008Q4							250.7177	66026.64	56073.11
2009Q1							251.8801	66949.77	56560.55
2009Q2							252.9048	67853.68	57068.00
2009Q3							253.9322	68680.18	57524.68
2009Q4							254.9778	69530.31	58005.99
2010Q1							256.2329	70398.21	58441.16
2010Q2							257.3748	71296.48	58935.54
2010Q3							258.5414	72102.80	59351.66
2010Q4							259.7872	72968.46	59805.39
2011Q1							261.0562	73887.63	60260.22
2011Q2							262.3007	74748.54	60700.16
2011Q3							263.6250	75561.69	61093.31
2011Q4							264.9472	76445.39	61539.10
2012Q1							266.2575	77349.46	61965.71
2012Q2							267.6442	78238.77	62402.78
2012Q3							269.0481	79067.33	62794.61
2012Q4							270.4765	79978.00	63246.70
2013Q1							271.9462	80937.50	63697.04
2013Q2							273.3923	81870.22	64156.56
2013Q3							274.8083	82777.18	64605.26
2013Q4							276.2041	83719.07	65082.96
2014Q1							277.6452	84748.46	65583.05
2014Q2							279.1098	85740.10	66077.86
2014Q3							280.5180	86676.81	66537.63
2014Q4							281.9092	87677.07	67045.74
2015Q1							283.3054	88759.57	67573.20
2015Q2							284.7407	89820.44	68109.96
2015Q3							286.1709	90840.91	68613.88
2015Q4							287.5193	91925.26	69167.66
2016Q1							288.9131	93094.04	69741.90
2016Q2							290.3538	94183.99	70279.08
2016Q3							291.7824	95209.67	70765.67
2016Q4							293.2204	96347.15	71328.18
2017Q1							294.7927	97577.23	71883.85
2017Q2							296.3936	98771.34	72431.16
2017Q3							298.0099	99952.90	72962.00
2017Q4							299.6334	101228.97	73553.67
2018Q1							301.2300	102544.75	74137.85
2018Q2							302.8437	103812.71	74710.92
2018Q3							304.5028	105011.95	75226.78
2018Q4							306.1980	106337.05	75819.98
2019Q1							307.9166	107701.61	76401.10
2019Q2							309.6486	109026.16	76979.91
2019Q3							311.3747	110320.35	77535.48
2019Q4							313.1011	111705.45	78148.19
2020Q1							314.7843	113128.86	78751.32
2020Q2							316.4997	114484.48	79332.55
2020Q3							318.2606	115799.04	79877.87
2020Q4							320.0713	117225.16	80484.06

Res Var Index	19	20	21	22	23	24	25	26	27
Res Var Name	POP	NMIG	EMP	RUEM	UEMP	REMP	LBFC	HH	HSTM
Description	Total Population	Net Migration	Employment, Total Non-Agriculture, By Place of Work NAICS	Unemployment Rate	Number Unemployed	Resident Employment	Total Labor Force	Households, Family and Non-Family	Housing Starts, Private Multi-Family
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	972.1467	3.2128	431.133	4.4202	22.721	491.349	514.070	349.280	2.1292
1984Q2	976.8630	3.1899	437.033	4.1974	21.879	499.383	521.262	352.174	2.5016
1984Q3	981.7980	3.3623	446.233	4.2374	22.402	506.253	528.655	354.876	2.9057
1984Q4	986.7579	3.3406	451.767	4.3661	23.367	511.805	535.171	357.498	3.1713
1985Q1	991.7429	3.2663	456.667	4.2602	22.979	516.414	539.392	360.025	4.4760
1985Q2	996.7530	3.2758	463.833	3.9038	21.179	521.361	542.540	362.811	7.0559
1985Q3	1003.7541	5.2509	467.833	3.5616	19.452	526.742	546.194	365.730	5.2348
1985Q4	1010.8045	5.2781	475.933	3.3035	18.201	532.784	550.986	368.765	5.2586
1986Q1	1017.9043	5.4013	481.967	3.1038	17.267	539.068	556.335	371.366	5.6555
1986Q2	1025.0540	5.3651	487.833	2.7485	15.405	545.121	560.526	374.578	4.7611
1986Q3	1032.2859	5.3598	493.733	2.1745	12.245	550.922	563.167	377.826	4.7317
1986Q4	1039.5687	5.3281	496.800	2.0635	11.729	556.562	568.290	381.063	4.7788
1987Q1	1046.9030	5.1922	504.767	2.1223	12.192	562.297	574.489	384.542	3.0920
1987Q2	1054.2890	5.2317	510.500	2.0940	12.144	567.603	579.746	387.626	2.9730
1987Q3	1061.2907	4.8348	516.900	2.4017	14.080	572.163	586.243	390.622	2.7792
1987Q4	1068.3389	4.8798	519.067	2.4708	14.590	575.931	590.521	393.547	2.7015
1988Q1	1075.4339	5.0112	524.533	2.2821	13.525	579.149	592.674	397.063	5.8205
1988Q2	1082.5760	5.0052	527.533	2.3612	14.071	581.863	595.935	399.687	3.5906
1988Q3	1088.0215	3.2550	530.233	2.5902	15.536	584.257	599.793	401.684	3.5902
1988Q4	1093.4944	3.2342	533.467	2.5793	15.519	586.159	601.678	403.691	2.5428
1989Q1	1098.9949	3.1436	534.933	2.6892	16.223	587.047	603.270	405.708	2.3825
1989Q2	1104.5230	3.1739	530.767	3.2305	19.609	587.316	606.925	407.735	1.2000
1989Q3	1106.4830	-0.3916	527.433	3.8341	23.432	587.666	611.098	408.445	1.5959
1989Q4	1108.4465	-0.3728	522.933	4.3536	26.778	588.260	615.038	409.157	1.2440
1990Q1	1110.4135	-0.4108	518.867	4.8802	30.203	588.660	618.863	409.869	0.5941
1990Q2	1112.3840	-0.3454	511.400	5.4414	33.799	587.330	621.129	409.349	0.6864
1990Q3	1111.7697	-2.8683	506.033	5.8672	36.421	584.345	620.766	409.912	0.4788
1990Q4	1111.1558	-2.7920	496.500	6.3932	39.598	579.794	619.392	411.021	1.0181
1991Q1	1110.5422	-2.6535	486.867	6.9130	42.651	574.337	616.988	412.780	0.2551
1991Q2	1109.9290	-2.6175	480.200	7.2756	44.721	569.953	614.674	413.897	0.1743
1991Q3	1111.8876	-0.0102	479.067	7.4385	45.605	567.494	613.099	415.202	0.1178
1991Q4	1113.8496	0.0241	482.467	7.5600	46.346	566.701	613.047	416.406	0.1132
1992Q1	1115.8151	-0.0411	482.900	7.6644	47.045	566.773	613.818	417.868	0.2490
1992Q2	1117.7840	0.0572	486.900	7.7064	47.403	567.711	615.114	419.069	0.1175
1992Q3	1120.6911	1.0902	486.633	7.5805	46.695	569.288	615.983	420.365	0.3425
1992Q4	1123.6058	1.1912	491.733	7.4171	45.813	571.865	617.679	421.292	0.2556
1993Q1	1126.5281	1.3920	495.633	7.0976	43.918	574.852	618.770	421.758	0.1424
1993Q2	1129.4580	1.4262	500.333	6.4611	39.941	578.231	618.172	422.684	0.8232
1993Q3	1132.7193	1.7841	506.033	6.0567	37.516	581.900	619.416	423.875	0.3148
1993Q4	1135.9901	1.8193	507.933	5.6866	35.306	585.565	620.871	425.159	0.2592
1994Q1	1139.2703	1.9206	515.067	5.2507	32.667	589.490	622.158	426.248	0.2220
1994Q2	1142.5600	1.9108	520.300	4.8619	30.322	593.357	623.679	427.532	0.2967
1994Q3	1146.2919	2.3340	526.300	4.5173	28.243	596.969	625.211	429.467	0.3385
1994Q4	1150.0360	2.3267	530.700	4.3514	27.292	599.923	627.216	431.694	0.4779
1995Q1	1153.7924	2.1944	534.067	4.2398	26.666	602.287	628.954	434.276	0.4772
1995Q2	1157.5610	2.2706	537.800	3.9987	25.183	604.813	629.796	436.506	0.3124
1995Q3	1161.8269	2.8316	540.500	3.9380	24.887	607.088	631.975	438.955	0.2190
1995Q4	1166.1084	2.9106	546.800	3.7489	23.748	609.728	633.477	441.345	0.0769
1996Q1	1170.4058	3.0975	548.633	3.7954	24.158	612.341	636.499	443.615	0.3561
1996Q2	1174.7190	3.1044	551.833	3.7810	24.184	615.437	639.621	446.005	0.2019
1996Q3	1178.3784	2.4418	555.500	3.7001	23.791	619.194	642.985	447.872	0.4548
1996Q4	1182.0491	2.4455	558.833	3.4583	22.336	623.545	645.881	449.800	0.7867
1997Q1	1185.7313	2.4036	562.233	3.1292	20.299	628.423	648.722	451.679	0.5542
1997Q2	1189.4250	2.4394	567.733	3.1936	20.895	633.369	654.264	453.607	0.6981
1997Q3	1193.5324	2.8768	573.267	3.1688	20.878	637.990	658.868	455.434	0.5849
1997Q4	1197.6540	2.9137	577.933	3.0834	20.428	642.094	662.522	457.372	0.8682
1998Q1	1201.7899	2.9789	584.200	2.9398	19.561	645.830	665.391	459.396	0.3505
1998Q2	1205.9400	2.9942	586.933	2.8642	19.148	649.374	668.521	461.334	0.4468
1998Q3	1209.9386	2.8441	590.000	2.7600	18.535	652.993	671.527	463.245	0.2030
1998Q4	1213.9504	2.8596	595.267	2.9296	19.828	656.972	676.799	465.182	0.2702
1999Q1	1217.9755	2.9168	599.700	2.8845	19.634	661.044	680.678	467.234	0.4400
1999Q2	1222.0140	2.9062	604.200	2.7633	18.889	664.664	683.553	469.171	0.2568
1999Q3	1226.6047	3.4343	607.867	2.6354	18.076	667.814	685.890	470.976	0.5577
1999Q4	1231.1953	3.4098	611.600	2.7198	18.753	670.740	689.493	472.774	0.2146
2000Q1	1235.7860	3.3027	616.233	2.6916	18.585	671.911	690.496	474.565	0.4224
2000Q2	1240.5540	3.5079	621.433	2.7482	19.059	674.437	693.496	476.363	0.3996
2000Q3	1245.0277	3.2415	622.967	2.6791	18.630	676.750	695.379	477.992	0.4658
2000Q4	1249.5176	3.2795	627.467	2.6629	18.578	679.066	697.644	479.553	0.4243
2001Q1	1254.0237	3.3426	633.200	2.8981	20.319	680.784	701.103	481.046	0.4003
2001Q2	1258.5460	3.3027	630.000	3.1817	22.383	681.092	703.475	482.470	0.6426
2001Q3	1262.5568	2.8547	624.433	3.6817	26.017	680.610	706.627	483.857	0.1996
2001Q4	1266.5804	2.8762	620.967	3.9649	28.089	680.335	708.424	485.175	0.9473
2002Q1	1270.6167	2.9027	619.433	4.2968	30.560	680.646	711.206	486.389	1.2940
2002Q2	1274.6660	2.9244	618.300	4.5564	32.525	681.303	713.828	488.640	0.9583
2002Q3	1277.8858	2.1038	618.900	4.6472	33.245	682.128	715.373	490.740	2.1502
2002Q4	1281.1137	2.1271	616.633	4.6741	33.487	682.951	716.438	492.749	1.3244
2003Q1	1284.3498	2.0976	614.667	4.4892	32.143	683.870	716.013	494.475	1.2568
2003Q2	1287.5940	2.0925	615.033	4.4651	32.030	685.313	717.343	495.445	1.2891
2003Q3	1290.4780	1.7191	619.833	4.4908	32.318	687.322	719.640	496.398	1.9909
2003Q4	1293.3686	1.7105	621.633	4.3302	31.206	689.459	720.665	497.411	1.7597
2004Q1	1296.2655	1.7340	622.367	4.1405	29.882	691.815	721.697	498.449	1.8759

Res Var Index	19	20	21	22	23	24	25	26	27
Res Var Name	POP	NMIG	EMP	RUEM	UEMP	REMP	LBFC	HH	HSTM
Description	Total Population	Net Migration	Employment, Total Non-Agriculture, By Place of Work NAICS	Unemployment Rate	Number Unemployed	Resident Employment	Total Labor Force	Households, Family and Non-Family	Housing Starts, Private Multi-Family
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	1299.1690	1.7255	626.667	3.9631	28.665	694.632	723.297	499.832	1.2098
2004Q3	1301.8534	1.4914	629.300	3.7472	27.152	697.450	724.603	501.221	1.3036
2004Q4	1304.5434	1.4822	630.767	3.5869	26.046	700.105	726.151	502.678	1.2428
2005Q1	1307.2389	1.4944	633.100	3.6959	26.964	702.581	729.544	504.199	0.9884
2005Q2	1309.9400	1.5065	635.000	3.6100	26.398	704.848	731.246	509.654	1.3283
2005Q3	1312.7878	1.6027	636.500	3.6243	26.576	706.709	733.285	510.868	0.6629
2005Q4	1315.7833	1.8215	636.133	3.5361	25.958	708.112	734.069	512.470	1.0173
2006Q1	1318.9273	1.9812	640.501	3.3943	24.982	711.032	736.015	514.140	1.0361
2006Q2	1322.2208	2.1418	643.181	3.4014	25.105	712.977	738.082	516.071	0.8549
2006Q3	1325.6648	2.3037	645.799	3.4034	25.180	714.950	740.140	518.038	0.8342
2006Q4	1329.1158	2.3218	647.468	3.4031	25.257	716.915	742.172	519.907	0.8996
2007Q1	1332.5735	2.3398	649.597	3.4016	25.313	718.847	744.160	521.751	0.9016
2007Q2	1336.0384	2.3581	651.647	3.4012	25.380	720.814	746.194	523.633	0.9269
2007Q3	1339.5648	2.4310	653.560	3.4009	25.447	722.809	748.256	525.532	0.9523
2007Q4	1343.0988	2.4497	655.744	3.4006	25.516	724.814	750.330	527.483	0.9696
2008Q1	1346.6398	2.4684	658.166	3.3999	25.581	726.834	752.415	529.462	0.9775
2008Q2	1350.1886	2.4874	660.449	3.3986	25.644	728.911	754.555	531.399	0.9600
2008Q3	1353.7831	2.5446	662.605	3.3968	25.703	730.991	756.694	533.349	0.9675
2008Q4	1357.3854	2.5639	664.959	3.3952	25.763	733.058	758.821	535.312	0.9712
2009Q1	1360.9951	2.5832	666.664	3.3933	25.821	735.136	760.957	537.306	0.9668
2009Q2	1364.6129	2.6027	668.462	3.3914	25.881	737.245	763.126	539.283	0.9554
2009Q3	1368.2252	2.6088	669.960	3.3893	25.938	739.335	765.273	541.239	0.9518
2009Q4	1371.8453	2.6294	671.480	3.3873	25.995	741.419	767.414	543.206	0.9459
2010Q1	1375.4734	2.6480	672.510	3.3851	26.050	743.492	769.542	545.176	0.9249
2010Q2	1379.1090	2.6678	673.591	3.3830	26.106	745.573	771.678	547.096	0.9114
2010Q3	1382.5753	2.5102	674.170	3.3806	26.156	747.554	773.710	548.924	0.9199
2010Q4	1386.0482	2.5293	674.935	3.3784	26.208	749.532	775.740	550.778	0.9091
2011Q1	1389.5285	2.5484	675.765	3.3764	26.260	751.510	777.770	552.655	0.9083
2011Q2	1393.0150	2.5677	676.557	3.3744	26.314	753.510	779.824	554.458	0.9138
2011Q3	1396.3656	2.4446	676.999	3.3715	26.358	755.431	781.789	556.168	0.9184
2011Q4	1399.7216	2.4634	677.645	3.3682	26.398	757.352	783.750	557.894	0.9023
2012Q1	1403.0838	2.4822	678.126	3.3643	26.434	759.285	785.719	559.622	0.8977
2012Q2	1406.4543	2.5046	678.759	3.3597	26.464	761.227	787.691	561.331	0.8939
2012Q3	1409.8062	2.5091	679.132	3.3542	26.486	763.165	789.652	562.999	0.8905
2012Q4	1413.1664	2.5226	679.753	3.3485	26.507	765.097	791.604	564.691	0.8837
2013Q1	1416.5355	2.5452	680.174	3.3426	26.526	767.046	793.571	566.358	0.8830
2013Q2	1419.9125	2.5681	680.703	3.3363	26.542	769.015	795.557	568.038	0.8728
2013Q3	1423.1885	2.4816	681.280	3.3299	26.555	770.916	797.471	569.658	0.8736
2013Q4	1426.4717	2.5041	681.874	3.3235	26.567	772.815	799.382	571.279	0.8739
2014Q1	1429.7629	2.5266	682.344	3.3170	26.580	774.730	801.309	572.888	0.8732
2014Q2	1433.0612	2.5494	682.989	3.3105	26.592	776.668	803.260	574.548	0.8593
2014Q3	1436.1951	2.4004	683.530	3.3039	26.600	778.506	805.107	576.123	0.8628
2014Q4	1439.3351	2.4224	684.185	3.2974	26.608	780.335	806.943	577.724	0.8634
2015Q1	1442.4819	2.4446	684.684	3.2909	26.616	782.178	808.794	579.359	0.8659
2015Q2	1445.6344	2.4669	685.462	3.2843	26.625	784.049	810.674	581.015	0.8797
2015Q3	1448.7855	2.4821	686.226	3.2778	26.633	785.906	812.540	582.647	0.8852
2015Q4	1451.9425	2.5047	687.141	3.2715	26.643	787.770	814.413	584.290	0.8882
2016Q1	1455.1059	2.5274	688.063	3.2653	26.654	789.631	816.285	585.968	0.8980
2016Q2	1458.2748	2.5502	688.957	3.2592	26.667	791.522	818.189	587.675	0.9076
2016Q3	1461.4132	2.5370	689.624	3.2532	26.678	793.381	820.059	589.384	0.9143
2016Q4	1464.5570	2.5599	690.625	3.2474	26.692	795.239	821.930	591.072	0.9128
2017Q1	1467.7070	2.5830	691.877	3.2419	26.708	797.114	823.822	592.745	0.9200
2017Q2	1470.8620	2.6061	693.270	3.2369	26.729	799.031	825.761	594.420	0.9329
2017Q3	1474.0546	2.6620	694.759	3.2323	26.754	800.952	827.707	596.115	0.9470
2017Q4	1477.2527	2.6856	696.335	3.2281	26.781	802.857	829.639	597.812	0.9562
2018Q1	1480.4568	2.7035	697.966	3.2242	26.812	804.778	831.590	599.492	0.9698
2018Q2	1483.6662	2.7235	699.599	3.2204	26.844	806.715	833.559	601.178	0.9821
2018Q3	1486.8267	2.7031	700.944	3.2166	26.875	808.629	835.504	602.847	0.9884
2018Q4	1489.9923	2.7270	702.704	3.2130	26.907	810.519	837.425	604.516	0.9763
2019Q1	1493.1636	2.7512	704.377	3.2095	26.940	812.435	839.375	606.184	0.9868
2019Q2	1496.3399	2.7754	706.062	3.2061	26.974	814.359	841.333	607.814	0.9913
2019Q3	1499.3467	2.6247	707.713	3.2027	27.004	816.179	843.184	609.401	1.0026
2019Q4	1502.3577	2.6483	709.431	3.1992	27.035	818.015	845.051	610.988	1.0091
2020Q1	1505.3735	2.6721	711.050	3.1957	27.065	819.850	846.914	612.588	1.0088
2020Q2	1508.3934	2.6959	712.551	3.1918	27.092	821.709	848.801	614.182	1.0138
2020Q3	1511.1360	2.4374	713.934	3.1882	27.116	823.392	850.508	615.654	1.0073
2020Q4	1513.8815	2.4601	715.347	3.1848	27.141	825.056	852.197	617.127	0.9950

Res Var Index	28	29	30	31	32	33	34	35	36
Res Var Name	HSTS	HSTT	HSOLD	HINC	PCI	RPCI	PINC	RPINC	RPIR
Description	Housing Starts, Private Single Family	Housing Starts Total Private	Home Sales, Existing Single-family units	Average Household Income	Per Capita Personal Income – By Place of Residence	Real Per Capita Personal Income	Personal Income, Total, By Place of Residence	Real Personal Income, Total	Real Income, Residence Adjustment
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	8.8378	10.9570	15.200	39.2809	14.1131	22.0593	13720.00	21444.87	2067.90
1984Q2	7.9622	10.4038	16.300	39.6849	14.3070	22.1474	13976.00	21635.01	2136.26
1984Q3	7.6684	10.5741	12.600	40.4733	14.6293	22.4727	14363.00	22063.66	2175.18
1984Q4	9.4995	12.6708	11.700	41.3541	14.9824	22.8718	14784.00	22568.92	2202.85
1985Q1	9.7410	14.2171	13.200	42.4888	15.4244	23.2954	15297.00	23103.06	2245.82
1985Q2	10.5343	17.5902	14.700	42.9866	15.6468	23.4536	15596.00	23377.40	2264.89
1985Q3	9.0169	14.2518	16.300	43.3079	15.7798	23.5014	15839.00	23589.60	2257.83
1985Q4	11.1747	16.4333	13.900	44.2612	16.1475	23.8615	16322.00	24119.28	2277.16
1986Q1	15.5154	21.1709	14.600	45.5292	16.6106	24.3704	16908.00	24806.70	2285.83
1986Q2	13.7531	18.5142	14.300	46.1399	16.8606	24.7223	17283.00	25341.64	2302.05
1986Q3	13.5674	18.2991	14.600	46.3599	16.9682	24.6943	17516.00	25491.54	2344.53
1986Q4	13.0298	17.8086	17.500	47.0289	17.2389	24.9106	17921.00	25896.28	2385.73
1987Q1	11.8098	14.9018	16.800	47.7503	17.5394	25.0619	18362.00	26237.43	2389.12
1987Q2	12.3730	15.3460	15.400	48.6371	17.8822	25.3339	18853.00	26709.26	2404.16
1987Q3	11.6998	14.4790	15.100	49.9537	18.3861	25.7848	19513.00	27365.16	2441.59
1987Q4	11.1964	13.8979	14.400	51.5364	18.9846	26.4002	20282.00	28204.31	2476.67
1988Q1	12.5773	18.3978	14.100	51.7878	19.1207	26.3610	20563.00	28349.46	2502.27
1988Q2	8.2599	11.8505	14.000	52.3635	19.3326	26.3613	20929.00	28538.12	2541.69
1988Q3	7.7653	11.3556	14.600	53.0392	19.5814	26.3854	21305.00	28707.91	2548.07
1988Q4	7.0208	9.5636	12.700	54.2866	20.0413	26.7438	21915.00	29244.18	2580.80
1989Q1	6.4051	8.7877	10.000	55.2885	20.4105	26.9172	22431.00	29581.81	2570.32
1989Q2	6.0648	7.2648	9.600	55.3741	20.4414	26.6112	22578.00	29392.70	2550.28
1989Q3	5.5336	7.1395	9.700	55.4738	20.4775	26.4896	22658.00	29310.26	2549.67
1989Q4	4.9087	6.1527	10.000	55.7097	20.5639	26.3833	22794.00	29244.45	2557.00
1990Q1	5.1058	5.6999	9.400	55.2127	20.3798	25.7659	22630.00	28610.80	2510.87
1990Q2	3.7655	4.4319	8.400	55.9547	20.5909	25.7557	22905.00	28650.23	2514.17
1990Q3	3.3691	3.8479	8.300	56.0827	20.6778	25.5440	22989.00	28399.01	2489.19
1990Q4	3.6860	4.7041	7.700	55.3353	20.4688	24.9625	22744.00	27737.26	2446.40
1991Q1	2.9906	3.2456	8.000	56.3812	20.9564	25.3667	23273.00	28170.77	2643.62
1991Q2	3.9135	4.0678	10.100	56.6156	21.1122	25.4143	23433.00	28208.06	2630.25
1991Q3	3.5952	3.7131	9.900	56.6062	21.1379	25.2665	23503.00	28093.47	2620.13
1991Q4	3.9180	4.0311	10.600	57.3071	21.4239	25.4054	23863.00	28297.84	2608.86
1992Q1	3.6335	3.8825	12.300	57.3842	21.4901	25.2878	23979.00	28216.56	2600.55
1992Q2	3.9003	4.0178	13.000	58.1336	21.7949	25.4834	24362.00	28484.91	2610.90
1992Q3	3.7764	4.1139	12.000	58.5777	21.9722	25.5125	24624.00	28591.67	2595.13
1992Q4	4.4427	4.6933	13.000	60.3169	22.6156	26.0948	25411.00	29320.27	2664.22
1993Q1	3.9187	4.0611	13.300	58.4031	21.8654	25.0992	24632.00	28274.94	2616.05
1993Q2	3.8781	4.7013	13.200	59.5197	22.2744	25.4048	25158.00	28693.63	2691.67
1993Q3	4.0073	4.3221	14.300	60.2819	22.5581	25.6403	25552.00	29043.29	2723.38
1993Q4	4.0997	4.3589	16.500	60.5679	22.6683	25.6304	25751.00	29115.93	2763.36
1994Q1	3.6871	3.9001	16.000	61.3351	22.9480	25.8441	26144.00	29443.43	2691.62
1994Q2	4.4166	4.7133	16.800	62.8374	23.5130	26.3368	26865.00	30091.40	2785.68
1994Q3	4.2278	4.5063	16.100	63.2155	23.6842	26.2953	27149.00	30142.11	2755.63
1994Q4	4.3981	4.8760	16.000	64.2376	24.1132	26.6526	27731.00	30651.47	2778.76
1995Q1	4.4029	4.8801	16.500	64.5073	24.2799	26.7080	28014.00	30815.43	2665.30
1995Q2	4.0999	4.4123	16.300	65.7585	24.7970	27.1266	28704.00	31400.69	2636.42
1995Q3	4.0936	4.3126	17.100	65.4600	24.7317	26.9406	28734.00	31300.31	2709.12
1995Q4	3.6331	3.7009	17.300	66.0210	24.9874	27.1057	29138.00	31608.18	2717.36
1996Q1	4.1762	4.5324	17.900	68.2732	25.8773	27.8977	30287.00	32651.63	2746.93
1996Q2	4.4237	4.6256	19.400	69.1562	26.2565	28.1263	30844.00	33040.53	2792.66
1996Q3	4.5250	4.9737	20.900	69.9106	26.5713	28.3502	31311.00	33407.31	2819.95
1996Q4	4.3943	5.1610	20.000	70.5557	26.8483	28.4555	31736.00	33635.75	2860.56
1997Q1	4.6566	5.2107	21.000	69.7642	26.5752	28.0385	31511.00	33246.11	2964.73
1997Q2	4.3494	5.0475	22.800	70.7528	26.9828	28.4146	32094.00	33797.03	2947.53
1997Q3	4.9123	5.4072	24.400	71.8129	27.4027	28.7789	32706.00	34348.55	2965.83
1997Q4	4.8194	5.6176	25.300	72.9582	27.8620	29.1638	33369.00	34928.19	3018.76
1998Q1	5.5377	5.8832	24.800	73.8231	28.2196	29.5153	33914.00	35471.19	2982.95
1998Q2	5.1800	5.6268	29.900	75.2926	28.8033	30.0751	34735.00	36268.81	3085.49
1998Q3	5.2661	5.4601	25.900	76.9528	29.4627	30.6622	35648.00	37099.33	3100.28
1998Q4	5.3408	5.6110	25.600	78.0362	29.9032	31.0061	36301.00	37639.85	3107.54
1999Q1	5.8090	6.2431	23.500	77.1690	29.6032	30.6176	36056.00	37291.47	3389.29
1999Q2	5.8087	6.0155	28.100	78.1377	29.9997	30.8261	36660.00	37669.93	3427.90
1999Q3	5.9380	6.4957	28.700	79.4435	30.5037	31.1724	37416.00	38236.17	3537.89
1999Q4	5.5910	5.8055	26.200	81.1508	31.1616	31.6561	38366.00	38974.79	3620.55
2000Q1	5.9264	6.3488	23.000	86.3042	33.1425	33.3774	40957.00	41247.38	3981.03
2000Q2	5.3120	5.7116	28.500	85.9178	32.9917	33.0654	40928.00	41019.47	3959.83
2000Q3	5.6236	6.0544	31.200	87.1124	33.4442	33.3645	41639.00	41539.72	4128.13
2000Q4	6.8586	7.2828	26.000	87.9798	33.7658	33.5354	42191.00	41903.13	4101.82
2001Q1	5.8335	6.2138	20.900	88.5736	33.9770	33.4742	42608.00	41977.50	4022.58
2001Q2	5.2956	5.9381	27.400	88.3226	33.8589	33.1476	42613.00	41717.74	3953.17
2001Q3	6.6405	6.8401	30.400	87.8854	33.6809	32.8265	42524.00	41571.59	3895.75
2001Q4	5.1642	6.1115	24.900	88.1147	33.7531	32.9501	42751.00	41733.94	3858.96
2002Q1	7.1926	8.4866	12.000	88.4908	33.8741	32.9922	43041.00	41920.47	3762.43
2002Q2	4.1520	5.1303	25.300	89.2232	34.2035	33.0836	43598.00	42170.53	3759.73
2002Q3	6.5708	8.7110	29.600	88.4786	33.9780	32.7212	43420.00	41813.93	3709.52
2002Q4	5.8408	7.1953	27.800	88.3086	33.9658	32.5754	43514.00	41732.84	3699.12
2003Q1	5.8813	7.1031	10.900	88.4494	34.0530	32.4157	43736.00	41633.11	3558.27
2003Q2	6.3898	7.6149	26.500	89.0008	34.2460	32.5471	44095.00	41907.43	3571.56
2003Q3	6.5460	8.5569	39.600	89.8855	34.5756	32.7005	44619.00	42199.29	3631.76
2003Q4	6.1316	7.8113	30.400	90.9449	34.9761	32.9727	45237.00	42645.84	3655.87
2004Q1	6.2436	8.1155	11.500	92.8140	35.6894	33.3285	46263.00	43202.53	3619.59

Res Var Index	28	29	30	31	32	33	34	35	36
Res Var Name	HSTS	HSTT	HSOLD	HINC	PCI	RPCI	PINC	RPINC	RPIR
Description	Housing Starts, Private Single Family	Housing Starts, Total Private	Home Sales, Existing Single-family units	Average Household Income	Per Capita Personal Income – By Place of Residence	Real Per Capita Personal Income	Personal Income, Total, By Place of Residence	Real Personal Income, Total	Real Income, Residence Adjustment
Start Year	1984	1[illegible]4	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	6.8606	8.0[illegible]03	27.600	94.0436	36.1816	33.4739	47006.00	43488.24	3669.20
2004Q3	6.5131	7.8[illegible]7	35.200	95.5607	36.7914	33.9141	47897.00	44151.21	3643.86
2004Q4	7.5724	8.8[illegible]2	31.100	97.7027	37.6477	34.4361	49113.00	44923.44	3663.36
2005Q1	6.7195	7.7[illegible]9	27.478	97.9138	37.7651	34.3519	49368.00	44906.13	3692.15
2005Q2	6.3177	7.6[illegible]0	24.277	98.1333	38.1804	34.4489	50014.00	45125.96	3634.33
2005Q3	7.3404	8.0[illegible]4	21.449	98.9810	38.5325	34.4514	50585.00	45227.37	3667.54
2005Q4	5.8483	6.8[illegible]6	18.951	99.9991	38.9722	34.5998	51279.00	45525.89	3689.73
2006Q1	5.6963	6.7[illegible]4	21.592	100.9841	39.3961	34.8162	51960.65	45920.05	3686.36
2006Q2	5.2100	6.0[illegible]8	19.875	101.9243	39.8146	35.0348	52643.75	46323.71	3709.15
2006Q3	5.0309	5.8[illegible]0	18.720	102.9689	40.2711	35.3306	53385.99	46836.47	3744.97
2006Q4	4.9675	5.8[illegible]1	18.280	103.8530	40.6575	35.5268	54038.56	47219.21	3770.02
2007Q1	4.9417	5.8[illegible]3	18.089	104.6593	41.0119	35.6855	54651.31	47553.56	3783.91
2007Q2	4.9139	5.8[illegible]8	18.281	105.5991	41.4217	35.8950	55340.93	47957.07	3806.35
2007Q3	4.9027	5.8[illegible]0	17.465	106.5054	41.8183	36.0824	56018.30	48334.68	3829.24
2007Q4	4.9097	5.8[illegible]3	17.601	107.4416	42.2311	36.2674	56720.53	48710.65	3849.47
2008Q1	4.8897	5.8[illegible]2	17.314	108.4192	42.6628	36.4573	57451.40	49094.87	3869.43
2008Q2	4.8799	5.8[illegible]99	17.468	109.5337	43.1453	36.7091	58254.23	49564.14	3893.40
2008Q3	4.8711	5.8[illegible]36	16.733	110.5659	43.5956	36.9278	59019.00	49992.21	3916.70
2008Q4	4.8671	5.8[illegible]3	17.057	111.6275	44.0590	37.1641	59805.02	50446.07	3939.45
2009Q1	4.8189	5.7[illegible]57	16.848	112.6757	44.5199	37.3872	60591.38	50883.82	3961.10
2009Q2	4.8081	5.7[illegible]35	17.233	113.8423	45.0267	37.6601	61444.03	51391.41	3984.24
2009Q3	4.8185	5.7[illegible]02	17.059	114.9772	45.5200	37.9197	62281.66	51882.71	4007.44
2009Q4	4.8554	5.8[illegible]14	17.307	116.0481	45.9893	38.1593	63090.19	52348.66	4031.01
2010Q1	4.8329	5.7[illegible]8	17.634	116.9834	46.4053	38.3328	63829.30	52725.78	4052.19
2010Q2	4.8663	5.7[illegible]6	17.910	118.0415	46.8661	38.5501	64633.52	53164.85	4073.97
2010Q3	4.8990	5.8[illegible]9	18.174	119.0558	47.3079	38.7452	65406.72	53568.20	4095.94
2010Q4	4.9244	5.8[illegible]35	18.391	120.0418	47.7408	38.9219	66171.02	53947.58	4117.84
2011Q1	4.9410	5.8[illegible]2	18.554	120.9872	48.1598	39.0804	66919.45	54303.37	4140.30
2011Q2	4.9450	5.8[illegible]8	18.637	121.9882	48.5948	39.2524	67693.30	54679.21	4163.99
2011Q3	4.9376	5.8[illegible]1	18.647	123.0072	49.0339	39.4186	68469.27	55042.75	4187.01
2011Q4	4.9283	5.8[illegible]06	18.647	124.0262	49.4746	39.5836	69250.67	55405.99	4210.73
2012Q1	4.9116	5.80[illegible]3	18.607	124.9539	49.8793	39.7188	69984.78	55728.79	4234.99
2012Q2	4.8937	5.78[illegible]6	18.567	126.0127	50.3347	39.8864	70793.39	56098.41	4258.85
2012Q3	4.8797	5.7[illegible]2	18.550	127.0194	50.7665	40.0324	71570.99	56437.99	4283.25
2012Q4	4.8779	5.70[illegible]5	18.555	128.0604	51.2143	40.1866	72374.36	56790.39	4307.40
2013Q1	4.8814	5.7[illegible]44	18.594	129.0894	51.6551	40.3320	73171.32	57131.75	4332.02
2013Q2	4.8803	5.7[illegible]1	18.606	130.2126	52.1348	40.5080	74026.86	57517.81	4357.30
2013Q3	4.8854	5.7[illegible]1	18.653	131.3412	52.6153	40.6869	74881.53	57905.09	4383.15
2013Q4	4.9000	5.7[illegible]9	18.754	132.4675	53.0950	40.8653	75738.49	58293.20	4409.43
2014Q1	4.9187	5.7[illegible]19	18.881	133.5805	53.5683	41.0320	76590.01	58666.06	4434.95
2014Q2	4.9302	5.78[illegible]05	18.962	134.7604	54.0734	41.2202	77490.44	59071.07	4460.61
2014Q3	4.9386	5.8[illegible]15	19.023	135.9379	54.5760	41.4094	78381.85	59471.92	4486.74
2014Q4	4.9618	5.8[illegible]2	19.170	137.1329	55.0883	41.6060	79290.47	59884.98	4513.36
2015Q1	4.9911	5.8[illegible]0	19.349	138.3356	55.6071	41.8033	80212.28	60300.56	4540.03
2015Q2	5.0203	5.89[illegible]9	19.527	139.5998	56.1530	42.0159	81176.67	60739.61	4566.74
2015Q3	5.0512	5.9[illegible]4	19.715	140.9048	56.7135	42.2379	82165.65	61193.62	4593.52
2015Q4	5.0748	5.9[illegible]30	19.861	142.1994	57.2712	42.4619	83154.42	61652.17	4621.28
2016Q1	5.0844	5.9[illegible]23	19.926	143.4817	57.8276	42.6779	84145.34	62100.84	4648.30
2016Q2	5.0827	5.99[illegible]4	19.926	144.7927	58.3988	42.8992	85161.52	62558.83	4674.94
2016Q3	5.0786	5.9[illegible]8	19.911	146.1126	58.9756	43.1216	86187.70	63018.51	4701.37
2016Q4	5.0814	5.9[illegible]12	19.937	147.4974	59.5768	43.3584	87253.68	63500.91	4727.90
2017Q1	5.0818	6.0[illegible]8	0.000	148.8861	60.1785	43.5671	88324.48	63943.67	4752.14
2017Q2	5.0756	6.0[illegible]5	0.000	150.3179	60.7983	43.7821	89425.87	64397.46	4776.07
2017Q3	5.0701	6.0[illegible]1	0.000	151.7008	61.3993	43.9791	90505.91	64827.56	4799.81
2017Q4	5.0726	6.0[illegible]7	0.000	153.2085	62.0514	44.2088	91665.63	65307.63	4823.11
2018Q1	5.0738	6.0[illegible]5	0.000	154.6120	62.6599	44.4054	92765.33	65740.26	4847.02
2018Q2	5.0697	6.0[illegible]8	0.000	156.1472	63.3229	44.6366	93950.03	66225.83	4870.37
2018Q3	5.0666	6.0[illegible]0	0.000	157.5787	63.9446	44.8325	95074.52	66658.11	4894.05
2018Q4	5.0682	6.0[illegible]5	0.000	159.1478	64.6225	45.0612	96287.00	67140.84	4917.01
2019Q1	5.0671	6.0[illegible]0	0.000	160.6584	65.2748	45.2676	97465.92	67591.87	4940.32
2019Q2	5.0625	6.0[illegible]8	0.000	162.1815	65.9327	45.4740	98657.71	68044.53	4963.66
2019Q3	5.0605	6.0[illegible]0	0.000	163.7419	66.6071	45.6893	99867.14	68504.14	4986.87
2019Q4	5.0601	6.0[illegible]2	0.000	165.4136	67.3270	45.9323	101149.31	69006.75	5010.83
2020Q1	5.0533	6.0[illegible]1	-0.000	167.0245	68.0242	46.1600	102401.85	69488.12	5035.18
2020Q2	5.0485	6.06[illegible]3	0.000	168.5589	68.6900	46.3608	103611.49	69930.28	5059.53
2020Q3	5.0475	6.05[illegible]8	0.000	170.0697	69.3457	46.5479	104790.83	70340.16	5082.89
2020Q4	5.0421	6.03[illegible]1	0.000	171.6797	70.0424	46.7541	106035.97	70780.23	5105.92

Res Var Index	37	38	39	40	41	42	43	44	45
Res Var Name	RPTR	PITP	TPTR	PINF	INDX	PRCG	PRCR	EGYG	EGYR
Description	Real Nonfarm Proprietors Income	Personal Income, Total Proprietor Income,	Real Total Proprietors Income	Personal Income, Nonfarm Proprietors Income	Industrial Production Index, Total	New Hampshire Natual Gas City Gate Price	New Hampshire Residential Natural Gas Price	New Hampshire Natural Gas Consumption by All	New Hampshire Residential Natural Gas Consumption
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	1569.29	1009.00	1577.10	1004.00		3.68	6.5255	1197.21	484.44
1984Q2	1574.33	1021.00	1580.52	1017.00		4.03	7.9521	519.21	110.31
1984Q3	1569.94	1027.00	1577.62	1022.00		4.26	7.0481	643.30	201.73
1984Q4	1589.17	1046.00	1596.80	1041.00		4.39	6.9658	2146.38	805.14
1985Q1	1748.93	1166.00	1761.01	1158.00		4.43	6.5717	1351.51	489.84
1985Q2	1788.23	1206.00	1798.72	1193.00		4.40	8.1352	623.48	114.10
1985Q3	1828.91	1235.00	1839.33	1228.00		4.30	7.1575	726.49	204.31
1985Q4	1866.36	1270.00	1876.70	1263.00		4.15	6.9209	2110.15	873.81
1986Q1	1888.23	1294.00	1898.50	1287.00		3.97	6.4062	1298.05	531.94
1986Q2	1953.08	1339.00	1963.34	1332.00		3.78	8.0455	570.83	123.16
1986Q3	1990.89	1377.00	2003.99	1368.00		3.57	7.0846	684.44	220.88
1986Q4	2027.37	1412.00	2040.37	1403.00		3.37	6.3498	2235.85	963.84
1987Q1	2170.50	1543.00	2204.79	1519.00		3.20	5.8229	1376.75	582.92
1987Q2	2290.82	1641.00	2324.82	1617.00		3.06	7.3999	597.69	134.91
1987Q3	2379.88	1724.00	2417.75	1697.00		2.98	6.4818	724.42	240.56
1987Q4	2440.52	1784.00	2480.84	1755.00		2.96	6.1953	2398.33	1019.61
1988Q1	2494.00	1832.00	2525.71	1809.00		2.97	5.5535	1474.62	613.79
1988Q2	2496.69	1854.00	2528.06	1831.00		3.01	7.1018	641.68	142.46
1988Q3	2499.56	1886.00	2541.33	1855.00		3.06	6.1894	777.82	250.68
1988Q4	2522.08	1918.00	2559.45	1890.00		3.11	6.6600	2454.40	1044.00
1989Q1	2537.35	1940.00	2558.46	1924.00		3.45	6.9100	1670.19	686.00
1989Q2	2473.48	1914.00	2491.70	1900.00		2.98	7.5000	683.90	155.00
1989Q3	2444.89	1904.00	2463.00	1890.00		3.17	6.8600	804.53	274.00
1989Q4	2406.89	1891.00	2426.13	1876.00		3.29	6.7600	2614.37	1118.00
1990Q1	2233.99	1790.00	2263.07	1767.00	65.76	3.86	7.7700	1578.09	655.00
1990Q2	2180.19	1763.00	2205.21	1743.00	66.01	3.03	8.3200	670.47	145.00
1990Q3	2149.47	1759.00	2172.95	1740.00	65.79	3.06	7.7700	769.90	203.00
1990Q4	2089.08	1731.00	2111.03	1713.00	63.64	3.50	6.9700	2239.51	905.40
1991Q1	2028.71	1697.00	2054.13	1676.00	61.26	3.72	7.2200	1472.14	598.73
1991Q2	2037.99	1716.00	2065.68	1693.00	61.45	2.87	7.8800	670.34	141.29
1991Q3	2067.89	1747.00	2088.21	1730.00	62.53	2.82	7.1500	790.03	248.54
1991Q4	2072.86	1770.00	2098.95	1748.00	63.34	3.40	6.9000	2563.66	1032.21
1992Q1	2140.45	1847.00	2173.40	1819.00	62.36	3.60	6.9400	1896.90	765.87
1992Q2	2187.64	1903.00	2225.05	1871.00	63.57	3.28	9.0900	771.86	159.16
1992Q3	2231.69	1952.00	2266.53	1922.00	64.74	3.42	8.0900	916.66	287.60
1992Q4	2314.61	2031.00	2343.45	2006.00	64.92	3.89	7.8600	2710.54	1048.26
1993Q1	2338.26	2050.00	2353.18	2037.00	66.10	3.59	5.9100	1844.28	721.41
1993Q2	2367.75	2091.00	2384.86	2076.00	67.06	3.91	8.6000	820.59	148.69
1993Q3	2414.21	2139.00	2431.26	2124.00	67.85	4.44	7.0900	1097.95	327.66
1993Q4	2395.89	2141.00	2420.77	2119.00	69.27	3.72	8.1500	3459.99	1293.93
1994Q1	2316.60	2071.00	2332.36	2057.00	70.80	3.94	6.5700	1719.34	664.72
1994Q2	2408.21	2164.00	2423.89	2150.00	72.37	3.38	9.4200	785.81	136.47
1994Q3	2395.91	2170.00	2409.24	2158.00	73.56	2.94	7.7600	957.73	275.28
1994Q4	2420.64	2202.00	2433.90	2190.00	75.83	3.09	7.3100	2671.03	1012.54
1995Q1	2333.10	2124.00	2336.40	2121.00	77.34	3.37	5.6500	1833.73	688.29
1995Q2	2310.42	2114.00	2312.61	2112.00	77.89	3.38	8.1600	829.71	159.54
1995Q3	2287.56	2103.00	2290.82	2100.00	78.69	3.86	7.2400	880.60	253.66
1995Q4	2311.66	2135.00	2316.00	2131.00	80.22	3.31	7.0900	3136.33	1192.56
1996Q1	2362.06	2198.00	2369.61	2191.00	80.77	4.06	5.9400	1881.34	697.68
1996Q2	2440.23	2285.00	2447.72	2278.00	83.09	4.30	8.4500	786.42	159.34
1996Q3	2518.00	2365.00	2523.34	2360.00	85.04	4.45	7.0500	1112.44	311.86
1996Q4	2526.71	2390.00	2533.07	2384.00	86.24	4.12	9.1000	2918.69	1060.97
1997Q1	2575.41	2442.00	2576.47	2441.00	88.28	4.45	6.6200	1966.49	744.23
1997Q2	2606.33	2476.00	2607.39	2475.00	90.66	3.72	9.0100	821.65	160.23
1997Q3	2629.75	2505.00	2630.81	2504.00	93.83	4.25	7.4700	1103.25	326.82
1997Q4	2670.20	2552.00	2671.24	2551.00	96.98	3.90	8.1900	3049.76	1140.13
1998Q1	2811.42	2690.00	2813.51	2688.00	99.01	3.93	6.3800	1753.26	642.79
1998Q2	2896.49	2776.00	2898.58	2774.00	99.29	3.53	9.0300	846.24	169.30
1998Q3	3024.31	2909.00	3027.43	2906.00	100.06	3.92	7.2900	1033.17	293.51
1998Q4	3137.60	3029.00	3140.72	3026.00	101.13	3.54	7.4400	3303.81	1245.59
1999Q1	3092.45	2999.00	3101.76	2990.00	102.18	3.52	5.6700	1820.87	672.39
1999Q2	3142.24	3067.00	3151.49	3058.00	103.52	3.81	8.8000	799.17	151.81
1999Q3	3177.15	3118.00	3186.35	3109.00	104.21	5.64	7.3800	1099.70	325.47
1999Q4	3257.89	3215.00	3266.02	3207.00	106.74	4.64	9.0600	3728.70	1315.98
2000Q1	3441.23	3418.00	3442.23	3417.00	108.77	4.19	7.9400	2046.72	631.76
2000Q2	3497.80	3491.00	3498.80	3490.00	110.81	4.54	12.4900	1093.48	178.26
2000Q3	3508.61	3517.00	3508.61	3517.00	111.60	6.67	10.9900	1254.81	302.05
2000Q4	3515.85	3540.00	3515.85	3540.00	112.27	6.94	11.9400	3171.00	1254.71
2001Q1	3483.68	3534.00	3481.70	3536.00	110.80	5.38	11.9900	2280.00	734.17
2001Q2	3508.70	3587.00	3505.77	3584.00	108.35	4.37	16.6700	1003.00	152.85
2001Q3	3545.77	3624.00	3542.83	3627.00	104.37	3.22	13.0000	1589.00	300.26
2001Q4	3548.52	3633.00	3546.57	3635.00	100.55	2.83	9.4600	2917.00	1031.54
2002Q1	3651.40	3732.00	3654.84	3749.00	99.43	3.90	10.0500	2179.00	633.51
2002Q2	3643.66	3743.00	3620.45	3767.00	100.24	4.29	12.2300	1657.00	212.02
2002Q3	3592.99	3725.00	3587.22	3731.00	100.88	4.51	11.4100	1038.00	272.71
2002Q4	3611.85	3771.00	3616.64	3766.00	99.41	4.94	9.8900	5812.00	1344.75
2003Q1	3560.18	3738.00	3558.27	3740.00	99.19	9.20	10.6700	3959.00	827.12
2003Q2	3634.29	3823.00	3633.34	3824.00	98.82	4.63	16.9500	4097.00	171.77
2003Q3	3719.71	3933.00	3719.71	3933.00	100.50	7.76	13.4700	4892.00	317.17
2003Q4	3760.51	3990.00	3761.45	3989.00	102.49	8.56	13.6700	5504.00	1305.83
2004Q1	3813.83	4086.00	3815.70	4084.00	103.71	6.02	14.6200	6282.00	707.83

Res Var Index	37	38	39	40	41	42	43	44	45
Res Var Name	RPTR	PITP	TPTR	PINF	INDX	PRCG	PRCR	EGYG	EGYR
Description	Real Nonfarm Proprietors Income	Personal Income, Total Proprietors Income,	Real Total Proprietors Income	Personal Income, Nonfarm Proprietors Income	Industrial Production Index, Total	New Hampshire Natual Gas City Gate Price	New Hampshire Residential Natural Gas Price	New Hampshire Natural Gas Consumption by All	New Hampshire Residential Natural Gas Consumption
Start Year	1984	19[illegible]4	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	3936.57	4258.[illegible]0	3939.35	4255.00	105.50	5.99	18.3500	4222.00	162.72
2004Q3	3993.22	4333.[illegible]0	3994.14	4332.00	107.73	7.63	16.3800	3269.00	260.08
2004Q4	3991.73	4364.[illegible]0	3991.73	4364.00	108.05	9.07	13.2700	6934.00	1345.51
2005Q1	4053.27	4455.[illegible]0	4052.36	4456.00	109.52	8.21	14.6600	5693.00	746.12
2005Q2	4123.36	4566.[illegible]0	4119.75	4570.00	110.23	9.65	17.3000	6050.00	182.29
2005Q3	4159.29	4647.[illegible]	4154.82	4652.00	109.68	12.75	18.5300	6050.00	245.80
2005Q4	4178.91	4703.[illegible]0	4175.36	4707.00	111.33	12.29	17.0100	6050.00	1183.13
2006Q1	4122.75	4663.[illegible]2	4121.45	4665.08	111.77	12.35			
2006Q2	4139.63	4702.71	4138.13	4704.40	112.82	12.99			
2006Q3	4182.86	4765.65	4180.99	4767.78	113.39	12.99			
2006Q4	4209.51	4815.[illegible]1	4207.65	4817.44	112.98	13.09			
2007Q1	4233.43	4863.[illegible]3	4231.71	4865.30	113.27	13.29			
2007Q2	4262.85	4917.56	4261.43	4919.19	113.64	13.37			
2007Q3	4294.27	4975.65	4293.18	4976.92	114.11	13.48			
2007Q4	4331.61	5042.[illegible]8	4330.57	5043.89	114.74	13.60			
2008Q1	4374.07	5117.[illegible]0	4373.14	5118.59	115.37	13.70			
2008Q2	4423.71	5198.[illegible]0	4422.85	5199.32	115.93	13.81			
2008Q3	4467.48	5273.[illegible]2	4466.69	5274.14	116.57	13.91			
2008Q4	4515.12	5351.96	4514.42	5352.78	117.32	14.02			
2009Q1	4568.64	5439.[illegible]3	4558.05	5440.24	118.22	14.12			
2009Q2	4625.99	5530.[illegible]1	4625.43	5530.88	119.11	14.23			
2009Q3	4672.41	5608.[illegible]7	4671.88	5608.91	119.99	14.33			
2009Q4	4719.52	5687.[illegible]4	4719.03	5687.93	120.99	14.44			
2010Q1	4765.16	5768.[illegible]4	4764.74	5768.66	121.97	14.54			
2010Q2	4818.34	5857.[illegible]7	4817.95	5857.74	122.89	14.65			
2010Q3	4862.76	5937.00	4862.41	5937.43	123.80	14.75			
2010Q4	4907.73	6019.[illegible]3	4907.41	6019.73	124.84	14.86			
2011Q1	4955.73	6106.72	4955.44	6107.07	125.89	14.96			
2011Q2	5002.42	6192.71	5002.16	6193.03	126.96	15.07			
2011Q3	5042.95	6272.[illegible]8	5042.72	6273.07	128.06	15.17			
2011Q4	5086.14	6356.79	5085.93	6357.05	129.14	15.27			
2012Q1	5131.01	6443.[illegible]2	5130.81	6443.57	130.27	15.38			
2012Q2	5176.27	6531.[illegible]7	5176.09	6532.20	131.45	15.48			
2012Q3	5216.80	6615.[illegible]0	5216.64	6615.61	132.64	15.59			
2012Q4	5259.15	6702.[illegible]3	5259.00	6702.32	133.84	15.69			
2013Q1	5303.14	6791.[illegible]1	5303.00	6791.98	135.04	15.80			
2013Q2	5347.81	6882.[illegible]1	5347.69	6882.76	136.25	15.90			
2013Q3	5389.32	6969.[illegible]1	5389.21	6969.34	137.47	16.01			
2013Q4	5430.65	7055.[illegible]4	5430.55	7055.87	138.82	16.11			
2014Q1	5477.32	7150.[illegible]7	5477.24	7150.78	140.31	16.22			
2014Q2	5525.82	7248.[illegible]6	5525.74	7248.86	141.82	16.32			
2014Q3	5568.55	7339.[illegible]5	5568.48	7339.14	143.36	16.43			
2014Q4	5613.22	7432.[illegible]7	5613.15	7432.16	144.94	16.53			
2015Q1	5663.94	7534.[illegible]4	5663.88	7534.22	146.46	16.64			
2015Q2	5714.26	7636.[illegible]7	5714.21	7636.94	148.08	16.74			
2015Q3	5760.95	7735.[illegible]6	5760.91	7735.32	149.72	16.85			
2015Q4	5810.50	7836.[illegible]6	5810.46	7837.02	151.42	16.95			
2016Q1	5865.79	7947.[illegible]8	5865.76	7948.03	153.21	17.06			
2016Q2	5920.40	8059.[illegible]1	5920.37	8059.46	155.03	17.16			
2016Q3	5970.00	8164.[illegible]8	5969.97	8164.91	156.90	17.27			
2016Q4	6022.99	8275.[illegible]8	6022.97	8275.92	158.79	17.37			
2017Q1	6082.50	8401.[illegible]4	6082.48	8401.67	160.34	17.47			
2017Q2	6142.63	8529.[illegible]6	6142.61	8529.99	161.86	17.58			
2017Q3	6204.05	8661.[illegible]6	6204.03	8661.49	163.39	17.68			
2017Q4	6267.69	8797.[illegible]9	6267.67	8797.31	164.99	17.79			
2018Q1	6332.56	8935.[illegible]8	6332.55	8935.81	166.77	17.89			
2018Q2	6394.44	9071.[illegible]4	6394.43	9071.36	168.58	18.00			
2018Q3	6454.16	9205.[illegible]5	6454.14	9205.57	170.31	18.10			
2018Q4	6518.44	9348.[illegible]1	6518.43	9348.12	172.06	18.21			
2019Q1	6583.23	9492.[illegible]5	6583.22	9492.87	173.85	18.31			
2019Q2	6644.54	9633.[illegible]0	6644.53	9633.92	175.67	18.42			
2019Q3	6705.98	9776.[illegible]4	6705.97	9776.16	177.44	18.52			
2019Q4	6769.54	9922.71	6769.54	9922.72	179.23	18.63			
2020Q1	6837.05	10075.[illegible]8	6837.05	10075.49	181.10	18.73			
2020Q2	6901.27	10225.[illegible]9	6901.27	10225.20	182.99	18.84			
2020Q3	6963.09	10373.[illegible]1	6963.08	10373.42	184.96	18.94			
2020Q4	7025.69	10525.[illegible]3	7025.68	10525.19	186.91	19.05			

Res Var Index	46	47	48	49	50	51	52	53	54
Res Var Name	RPRR	REGR	REVN	REVH	REVR	RVNN	RVNH	RVNR	CHGN
Description	Price Ratio: Residential Natural Gas Price : #2 Heating Oil Price	Energy Consumption Ratio: Residential Natural Gas : #2 Heating Oil	Revenue to Residential Non-Heating Customers	Revenue to Residential Heating Customers	Revenue to Residential Customers	Revenue (Normal)to Residential Non-Heating Customers	Revenue (Normal)to Residential Heating Customers	Revenue (Normal)to Residential Customers	Company Charge to Residential Non-Heating Customers
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	0.82	7.66	752751.94	11289571.06	12042323.00	808540.04	12114824.29	12923364.32	15.31
1984Q2	1.06	3.07	581476.22	5513371.78	6094848.00	504059.12	4711968.59	5216027.70	16.74
1984Q3	0.93	4.58	380216.74	1992888.26	2373105.00	406134.41	2170516.12	2576650.53	18.49
1984Q4	0.94	7.79	502572.26	6196457.74	6699030.00	728443.03	8875253.18	9603696.21	16.44
1985Q1	0.87	10.10	790465.08	12055076.92	12845542.00	858171.82	13132287.31	13990459.12	15.93
1985Q2	1.21	4.38	629792.32	5275733.68	5905526.00	543529.59	4638943.69	5182473.28	17.55
1985Q3	0.95	3.93	381831.36	2045846.64	2427678.00	408009.65	2234698.30	2642707.95	17.84
1985Q4	0.90	9.98	499251.59	6565254.41	7064506.00	708850.14	9105202.44	9814052.58	16.34
1986Q1	1.15	8.99	815021.41	12847626.59	13662648.00	854263.09	13466018.94	14320282.02	15.26
1986Q2	1.72	4.29	674649.44	5736794.56	6411444.00	549494.43	4730549.64	5280044.07	17.04
1986Q3	1.49	3.27	360845.32	2255569.68	2616415.00	442941.24	2770507.38	3213448.61	19.41
1986Q4	1.13	7.95	427845.59	7122481.41	7550327.00	617123.64	10284954.80	10902078.44	14.32
1987Q1	1.07	6.34	716399.87	13695659.13	14412059.00	708414.87	13538275.08	14246689.94	13.15
1987Q2	1.35	3.04	537940.44	6263717.56	6801658.00	434358.46	5104246.22	5538604.68	13.50
1987Q3	1.12	2.89	342192.91	2302752.09	2644945.00	321523.79	2165664.21	2487188.00	13.76
1987Q4	1.02	4.51	409987.47	6507769.56	6917757.03	556780.22	8823889.74	9380669.95	11.81
1988Q1	0.95	7.02	590669.51	13147606.61	13738276.12	604695.87	13487280.10	14091975.97	11.84
1988Q2	1.25	2.02	505161.58	5931693.95	6436855.53	381863.40	4476288.49	4858151.89	11.86
1988Q3	1.17	3.35	293647.31	2117423.58	2411070.89	310871.14	2263877.33	2574748.47	13.23
1988Q4	1.09	6.58	446079.03	8399083.49	8845162.52	587702.66	11012533.82	11600236.47	13.59
1989Q1	1.12	5.38	756667.24	15603140.61	16359807.85	776219.60	16057516.96	16833736.56	13.54
1989Q2	1.30	4.70	582092.98	6799186.74	7381279.72	434369.81	4927114.58	5361484.39	13.11
1989Q3	1.12	1.76	336046.94	2443196.71	2779243.65	356542.62	2607968.10	2964510.73	14.59
1989Q4	0.77	6.37	582522.41	8680818.07	9263340.48	700537.80	10961148.76	11661686.56	13.81
1990Q1	1.17	6.39	768128.95	16200724.53	16968853.48	792160.77	16079090.78	16871251.55	14.48
1990Q2	1.40	3.00	579517.46	7667273.15	8246790.61	452537.91	5489223.81	5941761.72	14.86
1990Q3	0.88	2.55	425931.15	2549001.15	2974932.30	423577.86	2715951.00	3139528.85	16.20
1990Q4	0.88	5.54	556541.30	7548689.24	8105230.54	769199.69	11126154.56	11895354.26	14.74
1991Q1	1.16	6.76	741246.56	14852220.34	15593466.90	786543.07	15768246.41	16554789.47	14.08
1991Q2	1.37	2.85	507186.56	6275591.36	6782777.92	437230.85	5026038.22	5463269.07	14.06
1991Q3	1.10	2.07	370121.48	2339603.57	2709725.05	384353.15	2539108.71	2923461.86	15.35
1991Q4	1.06	4.55	501643.02	7693219.71	8194862.73	666806.38	10938324.65	11605131.03	14.37
1992Q1	1.15	7.53	712281.95	16302861.34	17015143.29	729518.87	16612826.74	17342345.61	13.89
1992Q2	1.49	3.30	577015.80	8379018.42	8956034.22	431480.31	5464037.19	5895517.50	15.34
1992Q3	1.25	2.92	452851.38	2918038.12	3370889.50	482684.74	3252640.47	3735325.21	17.98
1992Q4	1.22	6.77	388084.83	11285495.79	11673580.62	425810.25	11647466.01	12073276.26	10.51
1993Q1	0.95	7.53	321821.94	17029421.62	17351243.57	320535.48	16851427.64	17171963.12	6.66
1993Q2	1.49	2.88	158336.13	3961887.25	4120223.37	159555.71	4009675.72	4169231.43	4.36
1993Q3	1.25	4.40	125037.38	1959514.23	2084551.61	116327.61	1775626.30	1891953.91	5.18
1993Q4	1.37	5.84	255502.45	10258150.38	10513652.83	254303.34	10107111.00	10361414.34	7.42
1994Q1	1.14	8.17	363840.25	18668799.28	19032639.52	346919.21	17179877.33	17526796.54	7.25
1994Q2	1.78	4.69	168334.44	4078333.78	4246668.22	167647.47	4052736.53	4220384.00	4.74
1994Q3	1.42	3.95	124382.61	1804742.34	1929124.95	127552.73	1831740.81	1959293.54	5.20
1994Q4	1.26	6.79	249360.52	9540479.62	9789840.14	259054.67	10675228.09	10934282.76	7.90
1995Q1	1.00	7.39	260397.42	15305437.96	15565835.38	273504.59	16836437.94	17109942.53	6.65
1995Q2	1.51	5.21	152087.00	4049093.63	4201180.63	151619.60	3970466.73	4122086.33	4.82
1995Q3	1.33	3.36	122252.85	1891660.50	2013913.35	113012.19	1768204.82	1881217.00	5.18
1995Q4	1.08	6.38	209204.87	11499577.96	11708782.83	208094.75	11260238.66	11468333.41	7.39
1996Q1	0.83	8.55	266076.86	17729259.86	17995336.72	265520.71	17647729.19	17913249.89	7.17
1996Q2	1.37	5.10	152830.51	4336455.63	4489286.14	149926.84	4104933.29	4254860.13	4.80
1996Q3	0.96	3.90	120391.27	1813393.80	1933785.06	119043.30	1805144.63	1924187.93	4.97
1996Q4	1.21	5.67	216781.60	12072792.73	12289574.33	215459.13	11858261.58	12073720.71	7.58
1997Q1	0.94	6.91	261203.64	16995869.56	17257073.20	267542.46	18235762.27	18503304.73	7.33
1997Q2	1.42	3.87	157278.85	4912565.92	5069844.76	152461.30	4455232.68	4607693.99	5.00
1997Q3	1.15	4.11	138865.97	2049273.81	2188139.78	137040.08	2019104.89	2156144.97	5.63
1997Q4	1.28	6.14	316932.71	11660667.16	11977599.87	316347.00	11571974.00	11888321.00	10.74
1998Q1	1.06	7.63	371753.32	17132264.62	17504017.94	394408.00	19659047.00	20053455.00	10.11
1998Q2	1.73	4.99	255484.24	5845650.99	6101135.23	267684.00	6482791.00	6750475.00	8.19
1998Q3	1.39	3.80	249985.63	3500822.81	3750808.44	227284.00	3290429.00	3517713.00	10.89
1998Q4	1.42	7.01	284481.11	8518624.44	8803105.56	289518.00	9135927.00	9425445.00	9.94
1999Q1	1.09	8.05	342303.82	18001231.88	18343535.71	352270.00	19042282.00	19394552.00	9.56
1999Q2	1.71	4.15	228332.30	5680385.25	5908717.55	234118.00	5887946.00	6122064.00	7.76
1999Q3	1.14	4.40	193247.54	2852328.23	3045575.77	196741.00	2927770.00	3124511.00	9.46
1999Q4	1.01	6.19	290581.75	9515756.95	9806338.70	298385.00	10178943.00	10477328.00	10.43
2000Q1	0.92	6.41	390120.79	22653616.70	23043737.49	396154.00	23277491.00	23673645.00	10.52
2000Q2	1.43	4.66	270555.46	7453633.32	7724188.78	271893.00	7659897.00	7931790.00	9.20
2000Q3	1.13	3.48	241060.31	3741678.34	3982738.64	238323.51	3687801.74	3926125.25	10.87
2000Q4	1.20	5.90	402403.12	14993263.95	15395667.07	400117.68	14785099.12	15185216.80	12.46
2001Q1	1.28	6.98	235736.00	10680073.00	10915809.00	227536.00	9667310.00	9894846.00	5.75
2001Q2	1.86	3.45	182763.00	3762558.00	3945321.00	180403.00	3610451.00	3790854.00	5.71
2001Q3	1.50	3.81	173379.00	2716640.00	2890019.00	173029.00	2711980.00	2885009.00	8.42
2001Q4	1.13	5.99	212106.00	4606402.00	4818508.00	210498.00	4571289.00	4781787.00	6.20
2002Q1	1.24	6.87	246000.00	7958869.00	8204869.00	256746.60	8876585.87	9133332.47	5.04
2002Q2	1.63	5.66	210672.00	4851889.00	5062561.00	211455.42	4305599.70	4517055.12	6.18
2002Q3	1.39	2.90	181246.59	2851038.58	3032285.17	181246.59	2851038.58	3032285.17	7.83
2002Q4	1.05	5.88	211916.07	5844542.32	6056458.39	210800.37	5767420.28	5978220.65	5.82
2003Q1	1.09	7.45	255692.00	9441387.00	9697079.00	261408.00	9798997.00	10060405.00	4.61
2003Q2	1.93	4.96	215032.00	5245740.00	5460772.00	209360.00	4875444.00	5084804.00	5.83
2003Q3	1.51	3.83	178337.00	2926033.00	3104420.00	178386.00	2924826.00	3103212.00	8.53
2003Q4	1.36	5.74	198446.00	5347579.00	5546025.00	191525.00	4858580.00	5050105.00	5.92
2004Q1	1.48	8.00	249362.00	9601010.00	9850372.00	260144.00	10333874.00	10594018.00	4.71

Res Var Index	46	47	48	49	50	51	52	53	54
Res Var Name	RPRR	REGR	REVN	REVH	REVR	RVNN	RVNH	RVNR	CHGN
Description	Price Ratio: Residential Natural Gas Price : #2 Heating Oil Price	Energy Consumption Ratio: Residential Natural Gas : #2 Heating Oil	Revenue to Residential Non-Heating Customers	Revenue to Residential Heating Customers	Revenue to Residential Customers	Revenue (Normal)to Residential Non-Heating Customers	Revenue (Normal)to Residential Heating Customers	Revenue (Normal)to Residential Customers	Company Charge to Residential Non-Heating Customers
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	1.77	5.66	197145.00	5000511.00	5197656.00	195325.00	4842926.00	5038251.00	6.05
2004Q3	1.27	3.43	171016.00	3006773.00	3177789.00	152322.00	2643372.00	2795694.00	8.20
2004Q4	1.03	7.21	184569.00	5149930.00	5334499.00	179679.00	4746919.00	4926598.00	6.13
2005Q1	1.06	11.17	231489.00	9423834.00	9655323.00	241242.00	10116906.00	10358148.00	4.75
2005Q2	1.17	5.91	189409.00	5169881.00	5359290.00	185749.00	4950953.00	5136702.00	6.08
2005Q3	1.08	4.32	161634.00	3047763.00	3209397.00	161625.00	3049194.00	3210819.00	8.42
2005Q4	1.04	9.30	178456.00	5218159.00	5396615.00	173453.00	4822475.00	4995928.00	6.08
2006Q1									
2006Q2									
2006Q3									
2006Q4									
2007Q1									
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2019Q3									
2019Q4									
2020Q1									
2020Q2									
2020Q3									
2020Q4									

Res Var Index	55	56	57	58	59	60	61	62	63
Res Var Name	CHGH	CHGR	CHNN	CHNH	CHNR	CDDN	CDDA	BDDN	BDDA
Description	Company Charge to Residential Heating Customers	Company Charge to Residential Customers	Company charge (Normal)to Residential Non-Heating Customers	Company charge (Normal)to Residential Heating Customers	Company charge (Normal)to Residential Customers	Normal Callendar Degree Days	Actual Callendar Degree Days	Normal Billing Degree Days	Actual Billing Degree Days
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	7.54	7.79	16.19	7.90	8.16	3652	3644	3826	3718
1984Q2	8.12	8.54	14.85	7.25	7.63	1032	1074	1494	1599
1984Q3	8.84	9.65	19.92	9.73	10.58	286	284	227	208
1984Q4	8.02	8.34	23.07	10.62	11.07	2611	2310	2106	1893
1985Q1	7.84	8.09	16.74	8.13	8.39	3652	3507	3813	3593
1985Q2	8.48	8.98	14.73	7.08	7.49	1032	980	1488	1378
1985Q3	8.52	9.29	19.47	9.25	10.07	286	213	225	183
1985Q4	7.89	8.19	23.03	10.74	11.17	2611	2596	2101	2016
1986Q1	7.53	7.77	15.51	7.58	7.82	3652	3418	3803	3628
1986Q2	8.23	8.71	12.98	6.17	6.52	1032	906	1477	1290
1986Q3	9.34	10.06	23.94	11.61	12.50	286	359	229	304
1986Q4	7.01	7.22	20.74	10.20	10.51	2611	2566	2103	2137
1987Q1	6.50	6.67	12.66	6.17	6.33	3652	3528	3793	3613
1987Q2	6.58	6.86	10.53	5.06	5.28	1032	915	1471	1346
1987Q3	6.64	7.12	12.73	6.16	6.60	286	308	230	246
1987Q4	5.89	6.07	15.96	7.91	8.16	2611	2564	2103	2096
1988Q1	5.86	5.99	11.96	5.88	6.01	3652	3601	3781	3685
1988Q2	5.83	6.07	8.87	4.33	4.51	1032	1017	1465	1434
1988Q3	6.41	6.83	14.10	6.92	7.38	286	298	231	257
1988Q4	6.76	6.93	17.90	8.93	9.16	2611	2680	2108	2145
1989Q1	6.70	6.86	13.43	6.55	6.71	3652	3415	3773	3549
1989Q2	6.49	6.76	9.72	4.77	4.98	1032	1002	1458	1473
1989Q3	7.06	7.53	15.39	7.41	7.91	286	228	227	184
1989Q4	6.80	7.02	17.06	9.15	9.41	2614	2988	2118	2253
1990Q1	7.14	7.31	14.49	6.74	6.91	3642	3175	3748	3528
1990Q2	7.34	7.61	11.61	5.22	5.45	1032	1021	1460	1454
1990Q3	7.79	8.41	16.27	8.29	8.87	285	220	226	162
1990Q4	7.20	7.46	19.25	9.38	9.70	2629	2195	2108	1762
1991Q1	6.96	7.13	14.15	6.80	6.97	3620	3298	3717	3376
1991Q2	6.90	7.17	11.17	4.85	5.08	1030	761	1440	1179
1991Q3	7.39	7.96	16.20	8.12	8.69	282	264	225	174
1991Q4	7.09	7.32	18.54	9.45	9.72	2645	2408	2102	1919
1992Q1	6.88	7.03	13.87	6.74	6.89	3651	3479	3706	3552
1992Q2	7.36	7.61	11.79	5.11	5.33	1026	1078	1437	1568
1992Q3	8.68	9.33	19.19	9.67	10.33	280	288	223	232
1992Q4	9.35	9.39	11.71	9.95	10.01	2605	2682	2088	2189
1993Q1	6.86	6.86	6.65	6.89	6.89	3606	3711	3710	3775
1993Q2	3.74	3.76	4.36	3.74	3.76	1025	907	1434	1396
1993Q3	6.23	6.15	5.11	6.06	5.99	275	250	223	178
1993Q4	8.58	8.55	7.43	8.60	8.57	2605	2628	2093	2154
1994Q1	6.94	6.95	7.25	6.94	6.95	3606	4027	3734	4105
1994Q2	3.83	3.86	4.74	3.83	3.86	1025	956	1428	1442
1994Q3	5.78	5.73	5.13	5.74	5.70	275	265	221	185
1994Q4	6.74	6.76	7.91	6.75	6.77	2605	2237	2071	1813
1995Q1	6.57	6.57	6.64	6.59	6.59	3606	3265	3717	3348
1995Q2	3.87	3.90	4.81	3.87	3.89	1025	1052	1428	1476
1995Q3	5.51	5.49	4.95	5.32	5.30	275	280	217	175
1995Q4	8.73	8.71	7.39	8.76	8.73	2599	2613	2072	2093
1996Q1	6.74	6.75	7.17	6.74	6.75	3651	3634	3717	3741
1996Q2	3.93	3.96	4.80	3.93	3.96	1019	1037	1428	1552
1996Q3	5.02	5.02	4.96	5.02	5.01	282	198	217	140
1996Q4	8.90	8.87	7.57	8.88	8.86	2594	2553	2072	2120
1997Q1	7.05	7.05	7.32	7.05	7.06	3617	3440	3703	3418
1997Q2	4.10	4.13	5.00	4.11	4.13	1023	1166	1432	1667
1997Q3	5.79	5.78	5.62	5.78	5.77	275	214	210	165
1997Q4	8.57	8.61	10.73	8.55	8.60	2603	2556	2054	2077
1998Q1	7.36	7.40	10.12	7.36	7.40	3602	2981	3669	3115
1998Q2	5.95	6.02	8.19	5.95	6.02	1020	831	1448	1221
1998Q3	9.73	9.80	10.76	9.66	9.72	274	164	205	138
1998Q4	7.48	7.54	9.94	7.48	7.54	2603	2292	2053	1842
1999Q1	7.03	7.07	9.56	7.03	7.07	3504	3342	3617	3394
1999Q2	5.67	5.73	7.76	5.68	5.74	984	896	1429	1341
1999Q3	8.52	8.57	9.45	8.50	8.55	257	168	199	133
1999Q4	8.04	8.10	10.43	8.04	8.10	2528	2345	2033	1862
2000Q1	8.18	8.21	10.52	8.17	8.20	3495	3344	3599	3480
2000Q2	6.94	7.00	9.19	6.88	6.94	979	997	1428	1356
2000Q3	9.87	9.93	10.88	9.88	9.93	251	241	194	193
2000Q4	10.62	10.66	12.45	10.60	10.64	2529	2614	2033	2044
2001Q1	3.77	3.80	5.61	3.49	3.52	3480	3551	3588	3679
2001Q2	3.31	3.37	5.56	3.16	3.23	977	880	1422	1401
2001Q3	7.71	7.75	8.67	7.77	7.82	248	158	192	113
2001Q4	4.19	4.25	5.69	3.63	3.69	2513	2082	2018	1653
2002Q1	3.24	3.27	4.83	3.14	3.17	3481	3013	3584	3045
2002Q2	4.12	4.17	6.20	3.61	3.68	979	992	1428	1399
2002Q3	7.07	7.11	9.32	7.92	7.99	244	111	189	130
2002Q4	3.91	3.95	5.88	3.94	3.99	2485	2578	1994	2016
2003Q1	2.93	2.96	4.52	2.86	2.89	3432	3815	3533	3913
2003Q2	4.00	4.05	6.07	4.27	4.32	975	1072	1420	1540
2003Q3	7.69	7.73	8.53	7.70	7.74	236	111	183	102
2003Q4	3.75	3.80	6.26	4.12	4.17	2503	2371	2004	1852
2004Q1	3.00	3.02	4.52	2.86	2.89	3459	3718	3563	3809

Res Var Index	55	56	57	58	59	60	61	62	63
Res Var Name	CHGH	CHGR	CHNN	CHNH	CHNR	CDDN	CDDA	BDDN	BDDA
Description	Company Charge to Residential Heating Customers	Company Charge to Residential Customers	Company charge (Normal)to Residential Non-Heating Customers	Company charge (Normal)to Residential Heating Customers	Company charge (Normal)to Residential Customers	Normal Callendar Degree Days	Actual Callendar Degree Days	Normal Billing Degree Days	Actual Billing Degree Days
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	4.23	4.28	6.13	4.35	4.40	977	897	1425	1331
2004Q3	7.66	7.69	7.30	6.75	6.78	231	133	180	119
2004Q4	3.93	3.98	6.46	4.26	4.32	2493	2394	1997	1868
2005Q1	3.05	3.08	4.56	2.91	2.94	3463	3581	3567	3636
2005Q2	4.14	4.18	6.27	4.38	4.43	968	977	1412	1466
2005Q3	7.85	7.87	8.42	7.84	7.87	224	75	175	80
2005Q4	3.89	3.93	6.37	4.23	4.28	2497	2362	1995	1792
2006Q1						3464			
2006Q2						969			
2006Q3						224			
2006Q4						2497			
2007Q1						3464			
2007Q2						969			
2007Q3						224			
2007Q4						2497			
2008Q1						3464			
2008Q2						969			
2008Q3						224			
2008Q4						2497			
2009Q1						3464			
2009Q2						969			
2009Q3						224			
2009Q4						2497			
2010Q1						3464			
2010Q2						969			
2010Q3						224			
2010Q4						2497			
2011Q1						3464			
2011Q2						969			
2011Q3						224			
2011Q4						2497			
2012Q1						3464			
2012Q2						969			
2012Q3						224			
2012Q4						2497			
2013Q1						3464			
2013Q2						969			
2013Q3						224			
2013Q4						2497			
2014Q1						3464			
2014Q2						969			
2014Q3						224			
2014Q4						2497			
2015Q1						3464			
2015Q2						969			
2015Q3						224			
2015Q4						2497			
2016Q1						3464			
2016Q2						969			
2016Q3						224			
2016Q4						2497			
2017Q1						3464			
2017Q2						969			
2017Q3						224			
2017Q4						2497			
2018Q1						3464			
2018Q2						969			
2018Q3						224			
2018Q4						2497			
2019Q1						3464			
2019Q2						969			
2019Q3						224			
2019Q4						2497			
2020Q1						3464			
2020Q2						969			
2020Q3						224			
2020Q4						2497			

C&I Var Index	1	2	3	4	5	6	7	8	9
C&I Var Name	CUSI	CUSC	CUSCI	USEC	USEI	USECI	USNC	USNI	USNCI
Description	ENGI: Number of Industiral Customers	ENGI: Number of Commercial Customers	ENGI: Number of C & I Customers	ENGI: Natural Gas Consumption per Commercial Customers	ENGI: Natural Gas Consumption per Industrial Customers	ENGI: Natural Gas Consumption per C & I Customers	ENGI: Natural Gas Consumption per Commercial Customers	ENGI: Natural Gas Consumption per Industrial Customers	ENGI: Natural Gas Consumption per C & I Customers
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	4332	78	4410	275.10	341.38	276.28	280.93	341.38	282.01
1984Q2	4332	109	4441	126.10	140.52	126.45	121.66	140.52	122.13
1984Q3	4251	105	4356	58.31	120.65	59.81	58.35	120.65	59.85
1984Q4	4432	71	4503	141.16	311.06	143.85	151.18	311.06	153.71
1985Q1	4669	74	4743	258.11	338.32	259.36	270.57	338.32	271.63
1985Q2	4683	66	4750	108.80	228.13	110.46	113.92	228.13	115.51
1985Q3	4609	63	4672	51.54	168.06	53.11	51.99	168.06	53.55
1985Q4	4745	66	4811	133.56	244.91	135.08	136.18	244.91	137.67
1986Q1	4834	70	4904	260.10	428.39	262.50	270.44	428.39	272.70
1986Q2	4858	72	4929	106.09	231.86	107.92	114.99	231.86	116.69
1986Q3	4853	70	4924	49.71	189.00	51.70	48.95	189.00	50.95
1986Q4	4969	71	5040	158.95	582.13	164.91	157.57	582.13	163.55
1987Q1	5160	71	5232	281.58	957.67	290.80	292.95	957.67	302.02
1987Q2	5211	70	5282	115.16	410.30	119.09	120.83	410.30	124.69
1987Q3	5093	55	5148	56.35	208.99	57.99	56.93	208.99	58.55
1987Q4	5247	99	5346	152.99	1046.02	169.58	154.05	1046.02	170.62
1988Q1	5437	113	5550	286.72	1155.49	304.36	293.19	1155.49	310.70
1988Q2	5430	92	5522	130.27	771.41	140.96	131.95	771.41	142.61
1988Q3	5382	88	5470	52.42	501.64	59.64	52.05	501.64	59.28
1988Q4	5766	102	5868	159.76	949.10	173.53	158.63	949.10	172.41
1989Q1	5971	103	6074	274.70	1380.53	293.51	289.01	1380.53	307.58
1989Q2	6011	93	6104	122.37	861.09	133.63	120.85	861.09	132.13
1989Q3	5895	291	6186	46.89	263.99	57.10	47.69	263.99	57.87
1989Q4	6159	342	6501	148.34	598.78	172.01	139.25	598.78	163.40
1990Q1	6412	356	6768	215.50	961.85	254.76	226.31	1016.09	267.85
1990Q2	6366	325	6692	95.14	473.32	113.53	96.00	477.46	114.55
1990Q3	6197	314	6511	41.27	240.81	50.89	41.50	240.18	51.08
1990Q4	6379	339	6718	107.84	530.16	129.13	120.75	590.22	144.42
1991Q1	6610	350	6960	202.64	947.25	240.12	219.36	1019.62	259.64
1991Q2	6538	316	6854	83.93	470.18	101.72	93.53	511.62	112.78
1991Q3	6407	299	6706	39.62	286.29	50.60	39.82	299.17	51.37
1991Q4	6610	319	6929	110.94	617.60	134.25	117.73	650.54	142.23
1992Q1	6817	328	7145	218.22	1155.66	261.25	226.48	1195.89	270.98
1992Q2	6782	316	7098	101.36	651.85	125.87	96.22	622.37	119.64
1992Q3	6623	307	6930	42.48	334.74	55.42	42.45	336.41	55.48
1992Q4	6813	313	7125	121.56	759.26	149.54	118.21	739.86	145.49
1993Q1	6999	314	7313	231.74	1360.34	280.20	228.86	1342.10	276.66
1993Q2	6953	311	7264	97.24	677.76	122.10	97.61	681.44	122.61
1993Q3	6758	299	7058	43.51	399.99	58.63	42.46	407.70	57.95
1993Q4	7020	300	7320	118.49	909.93	150.96	116.81	896.17	148.79
1994Q1	7278	308	7586	255.53	1628.76	311.29	236.31	1522.10	288.52
1994Q2	7230	309	7539	99.80	757.87	126.77	99.33	755.39	126.22
1994Q3	7051	302	7353	42.23	457.65	59.27	42.85	463.05	60.09
1994Q4	7316	300	7626	104.06	718.86	136.82	113.91	759.85	149.15
1995Q1	7570	304	7891	211.20	1166.14	263.09	231.16	1270.18	287.06
1995Q2	7469	296	7784	95.31	527.62	122.42	93.67	520.89	120.49
1995Q3	7186	283	7489	40.07	287.57	57.83	39.01	284.63	56.83
1995Q4	7439	294	7751	124.62	700.26	162.07	121.93	686.62	158.91
1996Q1	7687	300	8007	233.66	1331.09	294.18	232.60	1325.88	292.90
1996Q2	7616	300	7940	98.37	657.62	133.67	93.49	637.46	127.98
1996Q3	7362	292	7680	39.35	433.42	66.22	39.95	440.08	67.23
1996Q4	7633	302	7964	141.18	853.00	186.14	139.17	844.55	183.75
1997Q1	7857	311	8201	243.89	1261.86	305.51	261.12	1338.91	325.27
1997Q2	7819	308	8163	118.86	727.75	160.77	108.63	678.25	149.25
1997Q3	7578	302	7921	44.23	342.24	76.88	44.38	332.54	77.46
1997Q4	7910	300	8258	142.51	726.77	200.69	141.71	723.06	199.62
1998Q1	8170	312	8540	227.96	959.98	300.37	260.64	1080.88	337.90
1998Q2	8077	314	8451	97.46	413.30	147.10	106.98	432.39	157.30
1998Q3	7837	296	8195	43.40	294.19	90.22	41.47	300.05	89.20
1998Q4	8145	306	8518	116.30	519.60	179.30	124.47	546.04	189.62
1999Q1	8438	316	8835	245.47	932.91	329.96	259.37	985.29	346.66
1999Q2	8359	313	8758	94.22	333.66	148.04	97.14	343.05	151.72
1999Q3	8095	303	8485	38.49	140.67	83.36	39.17	142.00	84.07
1999Q4	8384	315	8792	114.00	421.69	182.86	121.47	450.39	192.78
2000Q1	8624	318	9036	257.79	1015.78	348.57	264.85	1042.30	357.25
2000Q2	8561	313	8968	98.95	374.81	152.06	102.59	387.69	156.41
2000Q3	8318	304	8715	41.42	183.58	87.73	41.36	181.09	88.02
2000Q4	8433	311	8835	125.98	559.03	200.29	124.38	551.82	198.39
2001Q1	8760	318	9078	262.26	1057.22	359.31	257.34	1070.69	353.31
2001Q2	8111	1151	9270	94.85	596.28	178.02	92.58	625.94	178.76
2001Q3	7381	1469	8861	16.46	345.70	77.83	16.19	349.77	78.76
2001Q4	7615	1538	9162	47.10	688.38	171.19	53.73	766.81	192.26
2002Q1	7851	1562	9424	115.71	1143.54	303.29	133.32	1313.36	347.27
2002Q2	7823	1405	9240	50.71	782.84	195.64	51.54	782.07	194.35
2002Q3	7336	873	8213	18.82	443.92	90.97	18.21	519.11	113.99
2002Q4	7648	1890	9543	66.30	594.88	199.21	64.76	586.04	196.37
2003Q1	8079	1627	9719	158.10	1447.72	389.60	166.49	1516.21	407.99
2003Q2	8077	1620	9710	57.50	702.46	185.32	50.84	634.01	168.10
2003Q3	8172	1674	9860	17.74	281.72	86.69	17.77	281.47	86.67
2003Q4	7820	1605	9439	59.96	688.27	192.76	50.72	599.68	169.81
2004Q1	8488	1606	10198	154.31	1358.46	370.32	170.34	1493.92	406.35

C&I Var Index	1	2	3	4	5	6	7	8	9
C&I Var Name	CUSI	CUSC	CUSCI	USEC	USEI	USECI	USNC	USNI	USNCI
Description	ENGI: Number of Industiral Customers	ENGI: Number of Commercial Customers	ENGI: Number of C & I Customers	ENGI: Natural Gas Consumption per Commercial Customers	ENGI: Natural Gas Consumption per Industrial Customers	ENGI: Natural Gas Consumption per C & I Customers	ENGI: Natural Gas Consumption per Commercial Customers	ENGI: Natural Gas Consumption per Industrial Customers	ENGI: Natural Gas Consumption per C & I Customers
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	8231	1675	9922	51.45	593.24	164.43	48.57	572.60	158.55
2004Q3	8296	1722	10031	17.94	287.83	88.84	17.92	286.97	88.67
2004Q4	7880	1638	9530	57.32	630.03	178.58	49.41	556.39	159.21
2005Q1	8611	1736	10361	142.86	1260.74	347.40	159.10	1394.69	383.16
2005Q2	8466	1744	10220	53.67	626.24	171.87	49.27	584.41	161.01
2005Q3	8602	1803	10418	16.95	276.12	68.38	16.96	273.68	67.97
2005Q4	8190	1738	9939	58.42	640.60	160.16	50.23	574.98	141.94
2006Q1									
2006Q2									
2006Q3									
2006Q4									
2007Q1									
2007Q2									
2007Q3									
2007Q4									
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2019Q2									
2019Q3									
2019Q4									
2020Q1									
2020Q2									
2020Q3									
2020Q4									

C&I Var Index	10	11	12	13	14	15	16	17	18	19
C&I Var Name	GASC	GASI	GASCI	GSNC	GSNI	GSNCI	CPI	GSP	RGSP	POP
Description	ENGI: Natural Gas Consumption of C & I Customers	ENGI: Natural Gas Consumption of Commercial Customers	ENGI: Natural Gas Consumption of Industrial Customers	ENGI: Normal Natural Gas Consumption of C & I Customers	ENGI: Normal Natural Gas Consumption of Commercial Customers	ENGI: Normal Natural Gas Consumption of Industrial Customers	Consumer Price Index	Gross State Product-- Aggregate	Real Gross State Product-- Aggregate	Total Population
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4	4
1984Q1	1191738	26741	1218479	1217009	26741	1243750	102.4745	13921.42	0.00	972.1467
1984Q2	546257	15316	561574	527048	15316	542364	102.8074	14488.95	0.00	976.8630
1984Q3	247883	12668	260552	248044	12668	260713	103.8268	14945.54	0.00	981.7980
1984Q4	625613	22189	647801	670031	22189	692220	104.6483	15355.14	0.00	986.7579
1985Q1	1205009	25148	1230157	1263182	25148	1288331	106.6530	15862.32	0.00	991.7429
1985Q2	509528	15133	524661	533513	15133	548646	108.1891	16297.67	0.00	996.7530
1985Q3	237564	10588	248152	239603	10588	250191	108.6814	16826.34	0.00	1003.7541
1985Q4	633791	16082	649873	646237	16082	662320	111.5703	17266.39	0.00	1010.8045
1986Q1	1257217	29987	1287204	1307228	29987	1337216	110.2958	17768.96	0.00	1017.9043
1986Q2	515339	16617	531956	558572	16617	575189	110.3331	18166.74	0.00	1025.0540
1986Q3	241240	13293	254533	237567	13293	250860	110.1529	18679.03	0.00	1032.2859
1986Q4	789816	41331	831147	782957	41331	824288	112.1824	19124.66	0.00	1039.5687
1987Q1	1453030	68314	1521344	1511736	68314	1580050	113.3266	19950.39	0.00	1046.9030
1987Q2	600112	28858	628970	629702	28858	658560	114.8597	20665.86	0.00	1054.2890
1987Q3	287015	11495	298510	289941	11495	301436	115.6120	21389.43	0.00	1061.2907
1987Q4	802693	103904	906597	808251	103904	912155	119.0104	22299.88	0.00	1068.3389
1988Q1	1559007	130185	1689192	1594184	130185	1724369	120.4813	21929.23	0.00	1075.4339
1988Q2	707388	70970	778358	716495	70970	787465	123.1453	22384.90	0.00	1082.5760
1988Q3	282133	44145	326278	280135	44145	324279	126.0685	22720.70	0.00	1088.0215
1988Q4	921124	97124	1018249	914606	97124	1011730	127.4170	23159.34	0.00	1093.4944
1989Q1	1640218	142654	1782872	1725703	142654	1868358	130.2364	23269.59	0.00	1098.9949
1989Q2	735553	80081	815634	726367	80081	806449	132.7346	23470.38	0.00	1104.5230
1989Q3	276422	76820	353242	281144	76820	357964	133.9616	23632.57	0.00	1106.4830
1989Q4	913605	204583	1118188	857648	204583	1062231	137.8583	23688.24	0.00	1108.4465
1990Q1	1381852	342418	1724270	1451195	361727	1812922	140.0640	23656.06	26630.39	1110.4135
1990Q2	605700	153987	759687	611191	155333	766524	139.7930	23659.55	26368.37	1112.3840
1990Q3	255770	75613	331383	257210	75418	332628	144.3361	23543.96	26043.09	1111.7697
1990Q4	687937	179549	867485	770294	199887	970181	148.0301	23223.97	25524.58	1111.1558
1991Q1	1339478	331855	1671333	1449951	357208	1807159	150.5876	23965.03	26038.07	1110.5422
1991Q2	548767	148420	697187	611474	161501	772974	150.4335	24344.52	26272.06	1109.9290
1991Q3	253816	85505	339321	255110	89353	344463	151.6294	24704.17	26464.20	1111.8876
1991Q4	733334	196808	930142	778185	207306	985491	153.2984	25018.77	26654.04	1113.8496
1992Q1	1487608	379058	1866666	1543929	392253	1936182	154.3808	25603.19	27160.75	1115.8151
1992Q2	687457	205984	893441	652603	196669	849272	155.4624	26111.44	27558.88	1117.7840
1992Q3	281343	102766	384109	281184	103279	384463	157.8577	26604.95	27964.59	1120.6911
1992Q4	828131	237395	1065526	805308	231331	1036639	158.2196	27154.68	28407.33	1123.6058
1993Q1	1621860	427148	2049008	1601719	421420	2023138	160.6911	27139.14	28208.94	1126.5281
1993Q2	676104	210784	886888	678665	211928	890594	160.1714	27398.99	28339.71	1129.4580
1993Q3	294038	119732	413770	286943	122038	408981	160.6923	27630.37	28473.16	1132.7193
1993Q4	831773	273284	1105057	819958	269149	1089107	162.9581	28122.86	28844.20	1135.9901
1994Q1	1859688	501659	2361347	1719776	468806	2188582	163.4125	28674.11	29317.26	1139.2703
1994Q2	721573	234181	955753	718190	233414	951604	163.9126	29194.20	29766.03	1142.5600
1994Q3	297768	138057	435825	302151	139687	441837	166.0462	29568.52	29998.40	1146.2919
1994Q4	761272	215420	1043344	833299	227703	1137371	166.1299	30078.28	30414.97	1150.0360
1995Q1	1598838	354897	2076039	1749939	386557	2265184	167.8976	30993.61	31293.57	1153.7924
1995Q2	711852	156176	952941	699603	154185	937901	168.3523	31447.27	31720.02	1157.5610
1995Q3	287931	81384	433119	280326	80551	425615	169.4686	32135.41	32347.28	1161.8269
1995Q4	926984	205875	1256186	906982	201867	1231694	171.4913	32807.00	32950.78	1166.1084
1996Q1	1796226	399770	2355436	1788084	398205	2345126	173.4123	33289.26	33477.73	1170.4058
1996Q2	749128	197068	1061389	711952	191027	1016222	174.7597	34157.21	34385.26	1174.7190
1996Q3	289711	126704	506592	294095	128649	516341	175.1595	34749.62	35028.78	1178.3784
1996Q4	1077657	257890	1487393	1062287	255336	1463374	178.6147	35539.30	35791.40	1182.0491
1997Q1	1916186	392439	2505526	2051539	416402	2667570	179.6608	35727.37	35762.99	1185.7313
1997Q2	929400	223903	1312369	849414	208675	1218346	179.9009	36330.66	36401.55	1189.4250
1997Q3	335123	103356	608985	336261	100427	613572	180.6567	36911.49	36949.04	1193.5324
1997Q4	1127190	217788	1657342	1120879	216678	1648536	181.4077	37306.48	37314.42	1197.6540
1998Q1	1862497	299834	2565236	2129478	337595	2885792	183.5020	38110.50	38412.85	1201.7899
1998Q2	787188	129639	1243146	864127	135627	1329343	184.4057	38569.93	39011.29	1205.9400
1998Q3	340074	87079	739307	324981	88816	730965	183.5080	39298.06	39801.89	1209.9386
1998Q4	947205	159172	1527304	1013731	167270	1615225	185.8773	40173.52	40745.97	1213.9504
1999Q1	2071379	294488	2915237	2188687	311022	3062754	186.5375	39687.58	40198.40	1217.9755
1999Q2	787572	104547	1290568	811953	107490	1328782	188.2712	39929.80	40377.99	1222.0140
1999Q3	311611	42623	707286	317095	43025	713371	188.3838	40311.35	40697.59	1226.6047
1999Q4	955724	132974	1607715	1018365	142022	1694881	192.1140	40979.27	41270.02	1231.1953
2000Q1	2223101	323356	3149562	2284015	331799	3228110	195.0051	42370.03	42496.59	1235.7860
2000Q2	847122	117190	1363763	878348	121216	1402712	196.2250	43480.92	43538.29	1240.5540
2000Q3	344554	55808	764566	344011	55052	767041	198.9644	43908.45	43855.41	1245.0277
2000Q4	1062358	173857	1769586	1048874	171616	1752792	201.2379	44564.59	44445.70	1249.5176
2001Q1	2297297	336549	3261793	2254173	340838	3207369	204.1178	44057.51	43706.81	1254.0237
2001Q2	769362	686511	1650177	750964	720669	1657025	206.0262	44439.53	43785.77	1258.5460
2001Q3	121522	507712	689692	119467	513688	697953	206.1879	44377.93	43577.22	1262.5568
2001Q4	358651	1058958	1566401	409164	1179613	1761386	206.7880	44689.03	43694.20	1266.5804
2002Q1	908433	1786590	2856238	1046733	2051909	3272633	207.7972	45409.13	44126.53	1270.6167
2002Q2	396685	1099808	1807681	403191	1098811	1795819	208.9996	45887.07	44388.04	1274.6660
2002Q3	138077	387687	741105	133585	453353	936134	210.0053	46398.15	44670.85	1277.8858
2002Q4	507081	1124517	1901100	495274	1107812	1874000	213.5279	46745.66	44714.58	1281.1137
2003Q1	1277318	2354793	3780479	1345115	2466194	3965185	215.4818	47123.45	44991.97	1284.3498
2003Q2	464408	1138198	1799405	410592	1027287	1632221	216.6297	47656.52	45448.36	1287.5940
2003Q3	144987	471592	854694	145260	471171	854547	218.0900	48695.54	46299.44	1290.4780
2003Q4	468892	1104725	1813399	396636	962525	1602778	221.2831	49320.49	46756.23	1293.3686
2004Q1	1309799	2303853	3779272	1445930	2533581	4143849	222.9654	50514.76	47506.08	1296.2655

C&I Var Index	10	11	12	13	14	15	16	17	18	19
C&I Var Name	GASC	GASI	GASCI	GSNC	GSNI	GSNCI	CPI	GSP	RGSP	POP
Description	ENGI: Natural Gas Consumption of C & I Customers	ENGI: Natural Gas Consumption of Commercial Customers	ENGI: Natural Gas Consumption of Industrial Customers	ENGI: Normal Natural Gas Consumption of C & I Customers	ENGI: Normal Natural Gas Consumption of Commercial Customers	ENGI: Normal Natural Gas Consumption of Industrial Customers	Consumer Price Index	Gross State Product– Aggregate	Real Gross State Product– Aggregate	Total Population
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4	4
2004Q2	423536	993500	1631400	399819	958929	1573135	225.8373	51525.29	48053.73	1299.1690
2004Q3	148840	495655	891172	148664	494174	889515	225.0902	52286.95	48660.33	1301.8534
2004Q4	451682	1031963	1701829	389334	911340	1517194	227.8726	53153.00	49190.69	1304.5434
2005Q1	1230242	2188883	3599249	1370077	2421452	3969780	229.1702	54039.51	49651.03	1307.2389
2005Q2	454406	1092152	1756465	417098	1019195	1645482	233.4505	54774.72	50023.85	1309.9400
2005Q3	145812	497814	712383	145910	493423	708090	236.8629	55720.46	50494.77	1312.7878
2005Q4	478401	1113493	1591894	411375	999434	1410809	237.9245	56310.66	50616.27	1315.7833
2006Q1							239.3080	57628.09	51387.60	1318.9273
2006Q2							240.4924	58496.71	51893.18	1322.2208
2006Q3							240.9599	59177.66	52269.32	1325.6648
2006Q4							241.9080	59832.92	52592.77	1329.1158
2007Q1							242.9320	60473.02	52888.57	1332.5735
2007Q2							243.8489	61103.39	53245.86	1336.0384
2007Q3							244.9061	61789.96	53646.33	1339.5648
2007Q4							246.1188	62563.78	54094.72	1343.0988
2008Q1							247.4104	63411.33	54540.22	1346.6398
2008Q2							248.4899	64281.08	55051.28	1350.1886
2008Q3							249.6398	65124.93	55534.69	1353.7831
2008Q4							250.7177	66026.64	56073.11	1357.3854
2009Q1							251.8801	66949.77	56560.55	1360.9951
2009Q2							252.9048	67853.68	57068.00	1364.6129
2009Q3							253.9322	68680.18	57524.68	1368.2252
2009Q4							254.9778	69530.31	58005.99	1371.8453
2010Q1							256.2329	70398.21	58441.16	1375.4734
2010Q2							257.3748	71296.48	58935.54	1379.1090
2010Q3							258.5414	72102.80	59351.66	1382.5753
2010Q4							259.7872	72968.46	59805.39	1386.0482
2011Q1							261.0562	73887.63	60260.22	1389.5285
2011Q2							262.3007	74748.54	60700.16	1393.0150
2011Q3							263.6250	75561.69	61093.31	1396.3656
2011Q4							264.9472	76445.39	61539.10	1399.7216
2012Q1							266.2575	77349.46	61965.71	1403.0838
2012Q2							267.6442	78238.77	62402.78	1406.4543
2012Q3							269.0481	79067.33	62794.61	1409.8062
2012Q4							270.4765	79978.00	63246.70	1413.1664
2013Q1							271.9462	80937.50	63697.04	1416.5355
2013Q2							273.3923	81870.22	64156.56	1419.9125
2013Q3							274.8083	82777.18	64605.26	1423.1885
2013Q4							276.2041	83719.07	65082.96	1426.4717
2014Q1							277.6452	84748.46	65583.05	1429.7629
2014Q2							279.1098	85740.10	66077.86	1433.0612
2014Q3							280.5180	86676.81	66537.63	1436.1951
2014Q4							281.9092	87677.07	67045.74	1439.3351
2015Q1							283.3054	88759.57	67573.20	1442.4819
2015Q2							284.7407	89820.44	68109.96	1445.6344
2015Q3							286.1709	90840.91	68613.88	1448.7855
2015Q4							287.5193	91925.26	69167.66	1451.9425
2016Q1							288.9131	93094.04	69741.90	1455.1059
2016Q2							290.3538	94183.99	70279.08	1458.2748
2016Q3							291.7824	95209.67	70765.67	1461.4132
2016Q4							293.2204	96347.15	71328.18	1464.5570
2017Q1							294.7927	97577.23	71883.85	1467.7070
2017Q2							296.3936	98771.34	72431.16	1470.8620
2017Q3							298.0099	99952.90	72962.00	1474.0546
2017Q4							299.6334	101228.97	73553.67	1477.2527
2018Q1							301.2300	102544.75	74137.85	1480.4568
2018Q2							302.8437	103812.71	74710.92	1483.6662
2018Q3							304.5028	105011.95	75226.78	1486.8267
2018Q4							306.1980	106337.05	75819.98	1489.9923
2019Q1							307.9166	107701.61	76401.10	1493.1636
2019Q2							309.6486	109026.16	76979.91	1496.3399
2019Q3							311.3747	110320.35	77535.48	1499.3467
2019Q4							313.1011	111705.45	78148.19	1502.3577
2020Q1							314.7843	113128.86	78751.32	1505.3735
2020Q2							316.4997	114484.48	79332.55	1508.3934
2020Q3							318.2606	115799.04	79877.87	1511.1360
2020Q4							320.0713	117225.16	80484.06	1513.8815

C&I Var Index	20	21	22	23	24	25	26	27	28
C&I Var Name	NMIG	EMP	RUEM	UEMP	REMP	LBFC	HH	HSTM	HSTS
Description	Net Migration	Employment, Total Non-Agriculture, By Place of Work NAICS	Unemployment Rate	Number Unemployed	Resident Employment	Total Labor Force	Households, Family and Non-Family	Housing Starts, Private Multi-Family	Housing Starts, Private Single Family
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	3.2128	431.133	4.4202	22.721	491.349	514.070	349.280	2.1292	8.8378
1984Q2	3.1899	437.033	4.1974	21.879	499.383	521.262	352.174	2.5016	7.9622
1984Q3	3.3623	446.233	4.2374	22.402	506.253	528.655	354.876	2.9057	7.6684
1984Q4	3.3406	451.767	4.3661	23.367	511.805	535.171	357.498	3.1713	9.4995
1985Q1	3.2663	456.667	4.2602	22.979	516.414	539.392	360.025	4.4760	9.7410
1985Q2	3.2758	463.833	3.9038	21.179	521.361	542.540	362.811	7.0559	10.5343
1985Q3	5.2509	467.833	3.5616	19.452	526.742	546.194	365.730	5.2348	9.0169
1985Q4	5.2781	475.933	3.3035	18.201	532.784	550.986	368.765	5.2586	11.1747
1986Q1	5.4013	481.967	3.1038	17.267	539.068	556.335	371.366	5.6555	15.5154
1986Q2	5.3651	487.833	2.7485	15.405	545.121	560.526	374.578	4.7611	13.7531
1986Q3	5.3598	493.733	2.1745	12.245	550.922	563.167	377.826	4.7317	13.5674
1986Q4	5.3281	496.800	2.0635	11.729	556.562	568.290	381.063	4.7788	13.0298
1987Q1	5.1922	504.767	2.1223	12.192	562.297	574.489	384.542	3.0920	11.8098
1987Q2	5.2317	510.500	2.0940	12.144	567.603	579.746	387.626	2.9730	12.3730
1987Q3	4.8348	516.900	2.4017	14.080	572.163	586.243	390.622	2.7792	11.6998
1987Q4	4.8798	519.067	2.4708	14.590	575.931	590.521	393.547	2.7015	11.1964
1988Q1	5.0112	524.533	2.2821	13.525	579.149	592.674	397.063	5.8205	12.5773
1988Q2	5.0052	527.533	2.3612	14.071	581.863	595.935	399.687	3.5906	8.2599
1988Q3	3.2550	530.233	2.5902	15.536	584.257	599.793	401.684	3.5902	7.7653
1988Q4	3.2342	533.467	2.5793	15.519	586.159	601.678	403.691	2.5428	7.0208
1989Q1	3.1436	534.933	2.6892	16.223	587.047	603.270	405.708	2.3825	6.4051
1989Q2	3.1739	530.767	3.2305	19.609	587.316	606.925	407.735	1.2000	6.0648
1989Q3	-0.3916	527.433	3.8341	23.432	587.666	611.098	408.445	1.5959	5.5336
1989Q4	-0.3728	522.933	4.3536	26.778	588.260	615.038	409.157	1.2440	4.9087
1990Q1	-0.4108	518.867	4.8802	30.203	588.660	618.863	409.869	0.5941	5.1058
1990Q2	-0.3454	511.400	5.4414	33.799	587.330	621.129	409.349	0.6864	3.7655
1990Q3	-2.8683	506.033	5.8672	36.421	584.345	620.766	409.912	0.4788	3.3691
1990Q4	-2.7920	496.500	6.3932	39.598	579.794	619.392	411.021	1.0181	3.6860
1991Q1	-2.6535	486.867	6.9130	42.651	574.337	616.988	412.780	0.2551	2.9906
1991Q2	-2.6175	480.200	7.2756	44.721	569.953	614.674	413.897	0.1743	3.9135
1991Q3	-0.0102	479.067	7.4385	45.605	567.494	613.099	415.202	0.1178	3.5952
1991Q4	0.0241	482.467	7.5600	46.346	566.701	613.047	416.406	0.1132	3.9180
1992Q1	-0.0411	482.900	7.6644	47.045	566.773	613.818	417.868	0.2490	3.6335
1992Q2	0.0572	486.900	7.7064	47.403	567.711	615.114	419.069	0.1175	3.9003
1992Q3	1.0902	486.633	7.5805	46.695	569.288	615.983	420.365	0.3425	3.7764
1992Q4	1.1912	491.733	7.4171	45.813	571.865	617.679	421.292	0.2556	4.4427
1993Q1	1.3920	495.633	7.0976	43.918	574.852	618.770	421.758	0.1424	3.9187
1993Q2	1.4262	500.333	6.4611	39.941	578.231	618.172	422.684	0.8232	3.8781
1993Q3	1.7841	506.033	6.0567	37.516	581.900	619.416	423.875	0.3148	4.0073
1993Q4	1.8193	507.933	5.6866	35.306	585.565	620.871	425.159	0.2592	4.0997
1994Q1	1.9206	515.067	5.2507	32.667	589.490	622.158	426.248	0.2220	3.6871
1994Q2	1.9108	520.300	4.8619	30.322	593.357	623.679	427.532	0.2967	4.4166
1994Q3	2.3340	526.300	4.5173	28.243	596.969	625.211	429.467	0.3385	4.2278
1994Q4	2.3267	530.700	4.3514	27.292	599.923	627.216	431.694	0.4779	4.3981
1995Q1	2.1944	534.067	4.2398	26.666	602.287	628.954	434.276	0.4772	4.4029
1995Q2	2.2706	537.800	3.9987	25.183	604.613	629.796	436.506	0.3124	4.0999
1995Q3	2.8316	540.500	3.9380	24.887	607.088	631.975	438.955	0.2190	4.0936
1995Q4	2.9106	546.800	3.7489	23.748	609.728	633.477	441.345	0.0769	3.6331
1996Q1	3.0975	548.633	3.7954	24.158	612.341	636.499	443.615	0.3561	4.1762
1996Q2	3.1044	551.833	3.7810	24.184	615.437	639.621	446.005	0.2019	4.4237
1996Q3	2.4418	555.500	3.7001	23.791	619.194	642.985	447.872	0.4548	4.5250
1996Q4	2.4455	558.833	3.4583	22.336	623.545	645.881	449.800	0.7867	4.3943
1997Q1	2.4036	562.233	3.1292	20.299	628.423	648.722	451.679	0.5542	4.6566
1997Q2	2.4394	567.733	3.1936	20.895	633.369	654.264	453.607	0.6981	4.3494
1997Q3	2.8768	573.267	3.1688	20.878	637.990	658.868	455.434	0.5849	4.9123
1997Q4	2.9137	577.933	3.0834	20.428	642.094	662.522	457.372	0.8682	4.8194
1998Q1	2.9789	584.200	2.9398	19.561	645.830	665.391	459.396	0.3505	5.5377
1998Q2	2.9942	586.933	2.8642	19.148	649.374	668.521	461.334	0.4468	5.1800
1998Q3	2.8441	590.000	2.7600	18.535	652.993	671.527	463.245	0.2030	5.2661
1998Q4	2.8596	595.267	2.9296	19.828	656.972	676.799	465.182	0.2702	5.3408
1999Q1	2.9168	599.700	2.8845	19.634	661.044	680.678	467.234	0.4400	5.8090
1999Q2	2.9062	604.200	2.7633	18.889	664.664	683.553	469.171	0.2568	5.8087
1999Q3	3.4343	607.867	2.6354	18.076	667.814	685.890	470.976	0.5577	5.9380
1999Q4	3.4098	611.600	2.7198	18.753	670.740	689.493	472.774	0.2146	5.5910
2000Q1	3.3027	616.233	2.6916	18.585	671.911	690.496	474.565	0.4224	5.9264
2000Q2	3.5079	621.433	2.7482	19.059	674.437	693.496	476.363	0.3996	5.3120
2000Q3	3.2415	622.967	2.6791	18.630	676.750	695.379	477.992	0.4658	5.6236
2000Q4	3.2795	627.467	2.6629	18.578	679.066	697.644	479.553	0.4243	6.8586
2001Q1	3.3426	633.200	2.8981	20.319	680.784	701.103	481.046	0.4003	5.8335
2001Q2	3.3627	630.000	3.1817	22.383	681.092	703.475	482.470	0.6426	5.2956
2001Q3	2.8547	624.433	3.6817	26.017	680.610	706.627	483.857	0.1996	6.6405
2001Q4	2.8762	620.967	3.9649	28.089	680.335	708.424	485.175	0.9473	5.1642
2002Q1	2.9027	619.433	4.2968	30.560	680.646	711.206	486.389	1.2940	7.1926
2002Q2	2.9244	618.300	4.5564	32.525	681.303	713.828	488.640	0.9583	4.1520
2002Q3	2.1038	618.900	4.6472	33.245	682.128	715.373	490.740	2.1502	6.5708
2002Q4	2.1271	616.633	4.6741	33.487	682.951	716.438	492.749	1.3244	5.8408
2003Q1	2.0976	614.667	4.4892	32.143	683.870	716.013	494.475	1.2568	5.8813
2003Q2	2.0925	615.033	4.4651	32.030	685.313	717.343	495.445	1.2891	6.3898
2003Q3	1.7191	619.833	4.4908	32.318	687.322	719.640	496.398	1.9909	6.5460
2003Q4	1.7105	621.633	4.3302	31.206	689.459	720.665	497.411	1.7597	6.1316
2004Q1	1.7340	622.367	4.1405	29.882	691.815	721.697	498.449	1.8759	6.2436

C&I Var Index	20	21	22	23	24	25	26	27	28
C&I Var Name	NMIG	EMP	RUEM	UEMP	REMP	LBFC	HH	HSTM	HSTS
Description	Net Migration	Employment, Total Non-Agriculture, By Place of Work NAICS	Unemployment Rate	Number Unemployed	Resident Employment	Total Labor Force	Households, Family and Non-Family	Housing Starts, Private Multi-Family	Housing Starts, Private Single Family
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	1.7255	626.667	3.9631	28.665	694.632	723.297	499.832	1.2098	6.8606
2004Q3	1.4914	629.300	3.7472	27.152	697.450	724.603	501.221	1.3036	6.5131
2004Q4	1.4822	630.767	3.5869	26.046	700.105	726.151	502.678	1.2428	7.5724
2005Q1	1.4944	633.100	3.6959	26.964	702.581	729.544	504.199	0.9884	6.7195
2005Q2	1.5065	635.000	3.6100	26.398	704.848	731.246	509.654	1.3283	6.3177
2005Q3	1.6627	636.500	3.6243	26.576	706.709	733.285	510.868	0.6629	7.3404
2005Q4	1.8215	636.133	3.5361	25.958	708.112	734.069	512.470	1.0173	5.8483
2006Q1	1.9812	640.501	3.3943	24.982	711.032	736.015	514.140	1.0361	5.6963
2006Q2	2.1418	643.181	3.4014	25.105	712.977	738.082	516.071	0.8549	5.2100
2006Q3	2.3037	645.799	3.4034	25.190	714.950	740.140	518.038	0.8342	5.0309
2006Q4	2.3218	647.468	3.4031	25.257	716.915	742.172	519.907	0.8996	4.9675
2007Q1	2.3398	649.597	3.4016	25.313	718.847	744.160	521.751	0.9016	4.9417
2007Q2	2.3581	651.647	3.4012	25.380	720.814	746.194	523.633	0.9269	4.9139
2007Q3	2.4310	653.560	3.4009	25.447	722.809	748.256	525.532	0.9523	4.9027
2007Q4	2.4497	655.744	3.4006	25.516	724.814	750.330	527.483	0.9696	4.9097
2008Q1	2.4684	658.166	3.3999	25.581	726.834	752.415	529.462	0.9775	4.8897
2008Q2	2.4874	660.449	3.3986	25.644	728.911	754.555	531.399	0.9600	4.8799
2008Q3	2.5446	662.605	3.3968	25.703	730.991	756.694	533.349	0.9675	4.8711
2008Q4	2.5639	664.959	3.3952	25.763	733.058	758.821	535.312	0.9712	4.8671
2009Q1	2.5832	666.664	3.3933	25.821	735.136	760.957	537.306	0.9668	4.8189
2009Q2	2.6027	668.462	3.3914	25.881	737.245	763.126	539.283	0.9554	4.8081
2009Q3	2.6088	669.960	3.3893	25.938	739.335	765.273	541.239	0.9518	4.8185
2009Q4	2.6284	671.480	3.3873	25.995	741.419	767.414	543.206	0.9459	4.8554
2010Q1	2.6480	672.510	3.3851	26.050	743.492	769.542	545.176	0.9249	4.8329
2010Q2	2.6678	673.591	3.3830	26.106	745.573	771.678	547.096	0.9114	4.8663
2010Q3	2.5102	674.170	3.3806	26.156	747.554	773.710	548.924	0.9199	4.8990
2010Q4	2.5293	674.935	3.3784	26.208	749.532	775.740	550.778	0.9091	4.9244
2011Q1	2.5484	675.765	3.3764	26.260	751.510	777.770	552.655	0.9083	4.9410
2011Q2	2.5677	676.557	3.3744	26.314	753.510	779.824	554.458	0.9138	4.9450
2011Q3	2.4446	676.999	3.3715	26.358	755.431	781.789	556.168	0.9184	4.9376
2011Q4	2.4634	677.645	3.3682	26.398	757.352	783.750	557.894	0.9023	4.9283
2012Q1	2.4822	678.126	3.3643	26.434	759.285	785.719	559.622	0.8977	4.9116
2012Q2	2.5046	678.759	3.3597	26.464	761.227	787.691	561.331	0.8939	4.8937
2012Q3	2.5001	679.132	3.3542	26.486	763.165	789.652	562.999	0.8905	4.8797
2012Q4	2.5226	679.753	3.3485	26.507	765.097	791.604	564.691	0.8837	4.8779
2013Q1	2.5452	680.174	3.3426	26.526	767.046	793.571	566.358	0.8830	4.8814
2013Q2	2.5681	680.703	3.3363	26.542	769.015	795.557	568.038	0.8728	4.8803
2013Q3	2.4816	681.280	3.3299	26.555	770.916	797.471	569.658	0.8736	4.8854
2013Q4	2.5041	681.874	3.3235	26.567	772.815	799.382	571.279	0.8739	4.9000
2014Q1	2.5266	682.344	3.3170	26.580	774.730	801.309	572.888	0.8732	4.9187
2014Q2	2.5494	682.989	3.3105	26.592	776.668	803.260	574.548	0.8593	4.9302
2014Q3	2.4004	683.530	3.3039	26.600	778.506	805.107	576.123	0.8628	4.9386
2014Q4	2.4224	684.185	3.2974	26.608	780.335	806.943	577.724	0.8634	4.9618
2015Q1	2.4446	684.684	3.2909	26.616	782.178	808.794	579.359	0.8659	4.9911
2015Q2	2.4669	685.462	3.2843	26.625	784.049	810.674	581.015	0.8797	5.0203
2015Q3	2.4821	686.226	3.2778	26.633	785.906	812.540	582.647	0.8852	5.0512
2015Q4	2.5047	687.141	3.2715	26.643	787.770	814.413	584.290	0.8882	5.0748
2016Q1	2.5274	688.063	3.2653	26.654	789.631	816.285	585.968	0.8980	5.0844
2016Q2	2.5502	688.957	3.2592	26.667	791.522	818.189	587.675	0.9076	5.0827
2016Q3	2.5370	689.624	3.2532	26.678	793.381	820.059	589.384	0.9143	5.0786
2016Q4	2.5599	690.625	3.2474	26.692	795.239	821.930	591.072	0.9128	5.0814
2017Q1	2.5830	691.877	3.2119	26.708	797.114	823.822	592.745	0.9200	5.0818
2017Q2	2.6061	693.270	3.2369	26.729	799.031	825.761	594.420	0.9329	5.0756
2017Q3	2.6620	694.759	3.2323	26.754	800.952	827.707	596.115	0.9470	5.0701
2017Q4	2.6856	696.335	3.2281	26.781	802.857	829.639	597.812	0.9562	5.0726
2018Q1	2.7095	697.966	3.2242	26.812	804.778	831.590	599.492	0.9698	5.0738
2018Q2	2.7335	699.599	3.2204	26.844	806.715	833.559	601.178	0.9821	5.0697
2018Q3	2.7031	700.944	3.2166	26.875	808.629	835.504	602.847	0.9884	5.0666
2018Q4	2.7270	702.704	3.2130	26.907	810.519	837.425	604.516	0.9763	5.0682
2019Q1	2.7512	704.377	3.2095	26.940	812.435	839.375	606.164	0.9868	5.0671
2019Q2	2.7754	706.062	3.2061	26.974	814.359	841.333	607.814	0.9913	5.0625
2019Q3	2.6247	707.713	3.2027	27.004	816.179	843.184	609.401	1.0026	5.0605
2019Q4	2.6483	709.431	3.1992	27.035	818.015	845.051	610.988	1.0091	5.0601
2020Q1	2.6721	711.050	3.1957	27.065	819.850	846.914	612.588	1.0088	5.0533
2020Q2	2.6959	712.551	3.1918	27.092	821.709	848.801	614.182	1.0138	5.0485
2020Q3	2.4374	713.934	3.1882	27.116	823.392	850.508	615.654	1.0073	5.0475
2020Q4	2.4601	715.347	3.1848	27.141	825.056	852.197	617.127	0.9950	5.0421

C&I Var Index	29	30	31	32	33	34	35	36	37
C&I Var Name	HSTT	HSOLD	HINC	PCI	RPCI	PINC	RPINC	RPIR	RPTR
Description	Housing Starts, Total Private	Home Sales, Existing Single-family units	Average Household Income	Per Capita Personal Income – By Place of Residence	Real Per Capita Personal Income	Personal Income, Total, By Place of Residence	Real Personal Income, Total	Real Income, Residence Adjustment	Real Nonfarm Proprietors Income
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	10.9670	15.200	39.2809	14.1131	22.0593	13720.00	21444.87	2067.90	1569.29
1984Q2	10.4638	16.300	39.6849	14.3070	22.1474	13976.00	21635.01	2136.26	1574.33
1984Q3	10.5741	12.600	40.4733	14.6293	22.4727	14363.00	22063.66	2175.18	1569.94
1984Q4	12.6708	11.700	41.3541	14.9824	22.8718	14784.00	22568.92	2202.85	1589.17
1985Q1	14.2171	13.200	42.4888	15.4244	23.2954	15297.00	23103.06	2245.82	1748.93
1985Q2	17.5902	14.700	42.9366	15.6468	23.4536	15596.00	23377.40	2264.89	1788.23
1985Q3	14.2518	16.300	43.3079	15.7798	23.5014	15839.00	23589.60	2257.83	1828.91
1985Q4	16.4333	13.900	44.2612	16.1475	23.8615	16322.00	24119.28	2277.16	1866.36
1986Q1	21.1709	14.600	45.5292	16.6106	24.3704	16908.00	24806.70	2285.83	1888.23
1986Q2	18.5142	14.300	46.1399	16.8606	24.7223	17283.00	25341.64	2302.05	1953.08
1986Q3	18.2991	14.600	46.3599	16.9682	24.6943	17516.00	25491.54	2344.53	1990.89
1986Q4	17.8086	17.500	47.0289	17.2389	24.9106	17921.00	25896.28	2385.73	2027.37
1987Q1	14.9018	16.800	47.7503	17.5394	25.0619	18362.00	26237.43	2389.12	2170.50
1987Q2	15.3460	15.400	48.0371	17.8822	25.3339	18853.00	26709.26	2404.16	2290.82
1987Q3	14.4790	15.100	49.9537	18.3861	25.7848	19513.00	27365.16	2441.59	2379.88
1987Q4	13.8979	14.400	51.5364	18.9846	26.4002	20282.00	28204.31	2476.67	2440.52
1988Q1	18.3978	14.100	51.7878	19.1207	26.3610	20563.00	28349.46	2502.27	2494.00
1988Q2	11.8505	14.000	52.3635	19.3326	26.3613	20929.00	28538.12	2541.69	2496.69
1988Q3	11.3556	14.600	53.0392	19.5814	26.3854	21305.00	28707.91	2548.07	2499.56
1988Q4	9.5636	12.700	54.2466	20.0413	26.7438	21915.00	29244.18	2580.80	2522.08
1989Q1	8.7877	10.000	55.2385	20.4105	26.9172	22431.00	29581.81	2570.32	2537.35
1989Q2	7.2648	9.600	55.3741	20.4414	26.6112	22578.00	29392.70	2550.28	2473.48
1989Q3	7.1295	9.700	55.4738	20.4775	26.4896	22658.00	29310.26	2549.67	2444.89
1989Q4	6.1527	10.000	55.7097	20.5639	26.3833	22794.00	29244.45	2557.00	2406.89
1990Q1	5.6999	9.400	55.7127	20.3798	25.7659	22630.00	28610.80	2510.87	2233.99
1990Q2	4.4519	8.400	55.9547	20.5909	25.7557	22905.00	28650.23	2514.17	2180.19
1990Q3	3.8479	8.300	56.0827	20.6778	25.5440	22989.00	28399.01	2489.19	2149.47
1990Q4	4.7041	7.700	55.3353	20.4688	24.9625	22744.00	27737.26	2446.40	2089.08
1991Q1	3.2456	8.000	56.3812	20.9564	25.3667	23273.00	28170.77	2643.62	2028.71
1991Q2	4.0878	10.100	56.0156	21.1122	25.4143	23433.00	28208.06	2630.25	2037.99
1991Q3	3.7131	9.900	56.6062	21.1379	25.2665	23503.00	28093.47	2620.13	2067.89
1991Q4	4.0311	10.600	57.3071	21.4239	25.4054	23863.00	28297.84	2608.86	2072.86
1992Q1	3.8825	12.300	57.3842	21.4901	25.2878	23979.00	28216.56	2600.55	2140.45
1992Q2	4.0178	13.000	58.1336	21.7949	25.4834	24362.00	28484.91	2610.90	2187.64
1992Q3	4.1189	12.000	58.5777	21.9722	25.5125	24624.00	28591.67	2595.13	2231.69
1992Q4	4.6983	13.000	60.3169	22.6156	26.0948	25411.00	29320.27	2664.22	2314.61
1993Q1	4.0611	13.300	58.4931	21.8654	25.0992	24632.00	28274.94	2616.05	2338.26
1993Q2	4.7013	13.200	59.5397	22.2744	25.4048	25158.00	28693.63	2691.67	2367.75
1993Q3	4.3221	14.300	60.3319	22.5581	25.6403	25552.00	29043.29	2723.38	2414.21
1993Q4	4.3589	16.500	60.5479	22.6683	25.6304	25751.00	29115.93	2763.36	2395.89
1994Q1	3.9091	16.000	61.3351	22.9480	25.8441	26144.00	29443.43	2691.62	2316.60
1994Q2	4.7133	16.800	62.8474	23.5130	26.3368	26865.00	30091.40	2785.68	2408.21
1994Q3	4.5663	16.100	63.2155	23.6842	26.2953	27149.00	30142.11	2755.63	2395.91
1994Q4	4.8760	16.000	64.2376	24.1132	26.6526	27731.00	30651.47	2778.76	2420.64
1995Q1	4.8801	16.500	64.5073	24.2799	26.7080	28014.00	30815.43	2665.30	2333.10
1995Q2	4.4123	16.300	65.7585	24.7970	27.1266	28704.00	31400.69	2636.42	2310.42
1995Q3	4.3126	17.100	65.4400	24.7317	26.9406	28734.00	31300.31	2709.12	2287.56
1995Q4	3.7099	17.300	66.0210	24.9874	27.1057	29138.00	31608.18	2717.36	2311.66
1996Q1	4.5324	17.900	68.2732	25.8773	27.8977	30287.00	32651.63	2746.93	2362.06
1996Q2	4.6256	19.400	69.1562	26.2565	28.1263	30844.00	33040.53	2792.66	2440.23
1996Q3	4.9797	20.900	69.9106	26.5713	28.3502	31311.00	33407.31	2819.95	2518.00
1996Q4	5.1810	20.000	70.5557	26.8483	28.4555	31736.00	33635.75	2860.56	2526.71
1997Q1	5.2107	21.000	69.7642	26.5752	28.0385	31511.00	33246.11	2964.73	2575.41
1997Q2	5.0475	22.800	70.7528	26.9828	28.4146	32094.00	33797.03	2947.53	2606.33
1997Q3	5.4972	24.400	71.8129	27.4027	28.7789	32706.00	34348.55	2965.83	2629.75
1997Q4	5.6876	25.300	72.9382	27.8620	29.1638	33369.00	34928.19	3018.76	2670.20
1998Q1	5.8882	24.800	73.8231	28.2196	29.5153	33914.00	35471.19	2982.95	2811.42
1998Q2	5.6268	29.900	75.2026	28.8033	30.0751	34735.00	36268.81	3085.49	2896.49
1998Q3	5.4691	25.900	76.9528	29.4627	30.6622	35648.00	37099.33	3100.28	3024.31
1998Q4	5.6110	25.600	78.0362	29.9032	31.0061	36301.00	37639.85	3107.54	3137.60
1999Q1	6.2491	23.500	77.1690	29.6032	30.6176	36056.00	37291.47	3389.29	3092.45
1999Q2	6.0655	28.100	78.1377	29.9997	30.8261	36660.00	37669.93	3427.90	3142.24
1999Q3	6.4957	28.700	79.4435	30.5037	31.1724	37416.00	38236.17	3537.89	3177.15
1999Q4	5.8055	26.200	81.1508	31.1616	31.6561	38366.00	38974.79	3620.55	3257.89
2000Q1	6.3488	23.000	86.3042	33.1425	33.3774	40957.00	41247.38	3981.03	3441.23
2000Q2	5.7116	28.500	85.9178	32.9917	33.0654	40928.00	41019.47	3959.83	3497.80
2000Q3	6.0894	31.200	87.1124	33.4442	33.3645	41639.00	41539.72	4128.13	3508.61
2000Q4	7.2828	26.000	87.3798	33.7658	33.5354	42191.00	41903.13	4101.82	3515.85
2001Q1	6.2338	20.900	88.5736	33.9770	33.4742	42608.00	41977.50	4022.58	3483.68
2001Q2	5.9381	27.400	88.2326	33.8589	33.1476	42613.00	41717.74	3953.17	3508.70
2001Q3	6.8401	30.400	87.8354	33.6809	32.9265	42524.00	41571.59	3895.75	3545.77
2001Q4	6.1115	24.900	88.1147	33.7531	32.9501	42751.00	41733.94	3858.96	3548.52
2002Q1	8.4866	12.000	88.4908	33.8741	32.9922	43041.00	41920.47	3762.43	3651.40
2002Q2	5.1103	25.300	89.2232	34.2035	33.0836	43598.00	42170.53	3759.73	3643.66
2002Q3	8.7210	29.600	88.4786	33.9780	32.7212	43420.00	41813.93	3709.52	3592.99
2002Q4	7.1653	27.800	88.3086	33.9658	32.5754	43514.00	41732.84	3699.12	3611.85
2003Q1	7.1381	10.900	88.4194	34.0530	32.4157	43736.00	41633.11	3558.27	3560.18
2003Q2	7.6789	26.500	89.0308	34.2460	32.5471	44095.00	41907.43	3571.56	3634.29
2003Q3	8.5369	39.600	89.8355	34.5756	32.7005	44619.00	42199.29	3631.76	3719.71
2003Q4	7.8913	30.400	90.5149	34.9761	32.9727	45237.00	42645.84	3655.87	3760.51
2004Q1	8.1195	11.500	92.8140	35.6894	33.3285	46263.00	43202.53	3619.59	3813.83

C&I Var Index	29	30	31	32	33	34	35	36	37
C&I Var Name	HSTT	HSOLD	HINC	PCI	RPCI	PINC	RPINC	RPIR	RPTR
Description	Housing Starts, Total Private	Home Sales, Existing Single-family units	Average Household Income	Per Capita Personal Income -- By Place of Residence	Real Per Capita Personal Income	Personal Income, Total, By Place of Residence	Real Personal Income, Total	Real Income, Residence Adjustment	Real Nonfarm Proprietors Income
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	8.0703	27.600	94.0436	36.1816	33.4739	47006.00	43488.24	3669.20	3936.57
2004Q3	7.8167	35.200	95.5607	36.7914	33.9141	47897.00	44151.21	3643.86	3993.22
2004Q4	8.8152	31.100	97.7027	37.6477	34.4361	49113.00	44923.44	3663.36	3991.73
2005Q1	7.7079	27.478	97.9138	37.7651	34.3519	49368.00	44906.13	3692.15	4053.27
2005Q2	7.6460	24.277	98.1333	38.1804	34.4489	50014.00	45125.96	3634.33	4123.36
2005Q3	8.0034	21.449	98.9810	38.5325	34.4514	50585.00	45227.37	3667.54	4159.29
2005Q4	6.8656	18.951	99.9991	38.9722	34.5998	51279.00	45525.89	3689.73	4178.91
2006Q1	6.7324	21.592	100.9841	39.3961	34.8162	51960.65	45920.05	3686.36	4122.75
2006Q2	6.0648	19.875	101.9243	39.8146	35.0348	52643.75	46323.71	3709.15	4139.63
2006Q3	5.8650	18.720	102.9689	40.2711	35.3306	53385.99	46836.47	3744.97	4182.86
2006Q4	5.8671	18.280	103.8530	40.6575	35.5268	54038.56	47219.21	3770.02	4209.51
2007Q1	5.8433	18.089	104.6593	41.0119	35.6855	54651.31	47553.56	3783.91	4233.43
2007Q2	5.8408	18.281	105.5991	41.4217	35.8950	55340.93	47957.07	3806.35	4262.85
2007Q3	5.8550	17.465	106.5054	41.8183	36.0824	56018.30	48334.68	3829.24	4294.27
2007Q4	5.8793	17.601	107.4416	42.2311	36.2674	56720.53	48710.65	3849.47	4331.61
2008Q1	5.8672	17.314	108.4192	42.6628	36.4573	57451.40	49094.87	3869.43	4374.07
2008Q2	5.8399	17.468	109.5337	43.1453	36.7091	58254.23	49564.14	3893.40	4423.71
2008Q3	5.8386	16.733	110.5659	43.5956	36.9278	59019.00	49992.21	3916.70	4467.48
2008Q4	5.8383	17.057	111.6275	44.0590	37.1641	59805.02	50446.07	3939.45	4515.12
2009Q1	5.7857	16.848	112.6757	44.5199	37.3872	60591.38	50883.82	3961.10	4568.64
2009Q2	5.7635	17.233	113.8123	45.0267	37.6601	61444.03	51391.41	3984.24	4625.99
2009Q3	5.7702	17.059	114.9772	45.5200	37.9197	62281.66	51882.71	4007.44	4672.41
2009Q4	5.8014	17.307	116.0481	45.9893	38.1593	63090.19	52348.66	4031.01	4719.52
2010Q1	5.7578	17.634	116.9834	46.4053	38.3328	63829.30	52725.78	4052.19	4765.16
2010Q2	5.7776	17.910	118.0415	46.8661	38.5501	64633.52	53164.85	4073.97	4818.34
2010Q3	5.8189	18.174	119.0558	47.3079	38.7452	65406.72	53568.20	4095.94	4862.76
2010Q4	5.8335	18.391	120.0418	47.7408	38.9219	66171.02	53947.58	4117.84	4907.73
2011Q1	5.8492	18.554	120.9872	48.1598	39.0804	66919.45	54303.37	4140.30	4955.73
2011Q2	5.8588	18.637	121.9882	48.5948	39.2524	67693.30	54679.21	4163.99	5002.42
2011Q3	5.8561	18.647	123.0572	49.0339	39.4186	68469.27	55042.75	4187.01	5042.95
2011Q4	5.8306	18.647	124.0262	49.4746	39.5836	69250.67	55405.99	4210.73	5086.14
2012Q1	5.8093	18.607	124.9539	49.8793	39.7188	69984.78	55728.79	4234.99	5131.01
2012Q2	5.7876	18.567	126.0127	50.3347	39.8864	70793.39	56098.41	4258.85	5176.27
2012Q3	5.7702	18.550	127.0194	50.7665	40.0324	71570.99	56437.99	4283.25	5216.80
2012Q4	5.7615	18.555	128.0604	51.2143	40.1866	72374.36	56790.39	4307.40	5259.15
2013Q1	5.7644	18.594	129.0394	51.6551	40.3320	73171.32	57131.75	4332.02	5303.14
2013Q2	5.7531	18.606	130.2126	52.1348	40.5080	74026.86	57517.81	4357.30	5347.81
2013Q3	5.7591	18.653	131.3412	52.6153	40.6869	74881.53	57905.09	4383.15	5389.32
2013Q4	5.7739	18.754	132.4675	53.0950	40.8653	75738.49	58293.20	4409.43	5430.65
2014Q1	5.7919	18.881	133.5805	53.5683	41.0320	76590.01	58666.06	4434.95	5477.32
2014Q2	5.7895	18.962	134.7604	54.0734	41.2202	77490.44	59071.07	4460.61	5525.82
2014Q3	5.8015	19.023	135.9379	54.5760	41.4094	78381.85	59471.92	4486.74	5568.55
2014Q4	5.8252	19.170	137.1329	55.0883	41.6060	79290.47	59884.98	4513.36	5613.22
2015Q1	5.8570	19.349	138.3356	55.6071	41.8033	80212.28	60300.56	4540.03	5663.94
2015Q2	5.8999	19.527	139.5998	56.1530	42.0159	81176.67	60739.61	4566.74	5714.26
2015Q3	5.9364	19.715	140.9048	56.7135	42.2379	82165.85	61193.62	4593.52	5760.95
2015Q4	5.9630	19.861	142.1994	57.2712	42.4619	83154.42	61652.17	4621.28	5810.50
2016Q1	5.9823	19.926	143.4817	57.8276	42.6779	84145.34	62100.84	4648.30	5865.79
2016Q2	5.9904	19.926	144.7927	58.3988	42.8992	85161.52	62558.83	4674.94	5920.40
2016Q3	5.9928	19.911	146.1126	58.9756	43.1216	86187.70	63018.51	4701.37	5970.00
2016Q4	5.9942	19.937	147.4974	59.5768	43.3584	87253.68	63500.91	4727.90	6022.99
2017Q1	6.0018	0.000	148.8861	60.1785	43.5671	88324.48	63943.67	4752.14	6082.50
2017Q2	6.0085	0.000	150.3179	60.7983	43.7821	89425.87	64397.46	4776.07	6142.63
2017Q3	6.0171	0.000	151.7008	61.3993	43.9791	90505.91	64827.58	4799.81	6204.05
2017Q4	6.0287	0.000	153.2085	62.0514	44.2088	91665.63	65307.63	4823.11	6267.69
2018Q1	6.0435	0.000	154.6120	62.6599	44.4054	92765.33	65740.26	4847.02	6332.56
2018Q2	6.0518	0.000	156.1472	63.3229	44.6366	93950.03	66225.83	4870.37	6394.44
2018Q3	6.0550	0.000	157.5787	63.9446	44.8325	95074.52	66658.11	4894.05	6454.16
2018Q4	6.0445	0.000	159.1478	64.6225	45.0612	96287.00	67140.84	4917.01	6518.44
2019Q1	6.0540	0.000	160.6584	65.2748	45.2676	97465.92	67591.87	4940.32	6583.23
2019Q2	6.0538	0.000	162.1815	65.9327	45.4740	98657.71	68044.53	4963.66	6644.54
2019Q3	6.0630	0.000	163.7119	66.6071	45.6893	99867.14	68504.14	4986.87	6705.98
2019Q4	6.0692	0.000	165.4136	67.3270	45.9323	101149.31	69006.75	5010.83	6769.54
2020Q1	6.0621	0.000	167.0245	68.0242	46.1600	102401.85	69488.12	5035.18	6837.05
2020Q2	6.0623	0.000	168.5589	68.6900	46.3608	103611.49	69930.28	5059.53	6901.27
2020Q3	6.0548	0.000	170.0697	69.3457	46.5479	104790.83	70340.16	5082.89	6963.09
2020Q4	6.0371	0.000	171.6797	70.0424	46.7541	106035.97	70780.23	5105.92	7025.69

C&I Var Index	38	39	40	41	42	43	44	45	46
C&I Var Name	PITP	TPTR	PINF	INDX	PRCO	PRCG	PRCR	PRCC	PRCI
Description	Personal Income, Total Proprietors Income,	Real Total Proprietors Income	Personal Income, Nonfarm Proprietors Income	Industrial Production Index, Total	New Hampshire #2 Heating Oil Production Price	New Hampshire Natual Gas City Gate Price	New Hampshire Residential Natural Gas Price	New Hampshire Commercial Natural Gas Price	New Hampshire Industrial Natural Gas Price
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	1009.00	1577.10	1004.00		7.9574	3.68	6.5255	6.4017	5.2470
1984Q2	1021.00	1580.52	1017.00		7.5289	4.03	7.9521	6.4233	4.6399
1984Q3	1027.00	1577.62	1022.00		7.5510	4.26	7.0481	6.1289	3.7502
1984Q4	1046.00	1596.80	1041.00		7.4402	4.39	6.9658	6.3252	4.6838
1985Q1	1166.00	1761.01	1158.00		7.5584	4.43	6.5717	6.0109	4.9795
1985Q2	1200.00	1798.72	1193.00		6.7383	4.40	8.1352	6.0583	4.4135
1985Q3	1235.00	1839.33	1228.00		7.5584	4.30	7.1575	5.7757	3.5684
1985Q4	1270.00	1876.70	1263.00		7.6619	4.15	6.9209	6.6060	4.8710
1986Q1	1294.00	1898.50	1287.00		5.5561	3.97	6.4062	6.1713	5.1879
1986Q2	1339.00	1963.34	1332.00		4.6769	3.78	8.0455	6.2724	4.6084
1986Q3	1377.00	2003.99	1368.00		4.7508	3.57	7.0846	5.9708	3.7336
1986Q4	1412.00	2040.37	1403.00		5.6300	3.37	6.3498	5.8647	4.3406
1987Q1	1543.00	2204.79	1519.00		5.4305	3.20	5.8229	5.4408	4.6358
1987Q2	1641.00	2324.82	1617.00		5.4896	3.06	7.3999	5.5649	4.1198
1987Q3	1724.00	2417.75	1697.00		5.7630	2.98	6.4818	5.2863	3.3569
1987Q4	1784.00	2480.84	1755.00		6.0955	2.96	6.1953	5.7644	4.1970
1988Q1	1832.00	2525.71	1809.00		5.8369	2.97	5.5535	5.2525	4.4732
1988Q2	1854.00	2528.06	1831.00		5.6596	3.01	7.1018	5.3590	3.9572
1988Q3	1886.00	2541.33	1855.00		5.2828	3.06	6.1894	5.0903	3.2140
1988Q4	1918.00	2559.45	1890.00		6.1324	3.11	6.6600	6.2000	4.5775
1989Q1	1940.00	2558.46	1924.00		6.1472	3.45	6.9100	6.3100	4.8695
1989Q2	1914.00	2491.70	1900.00		5.7482	2.98	7.5000	6.1600	4.3231
1989Q3	1904.00	2463.00	1896.00		6.1472	3.17	6.8600	6.0000	3.5080
1989Q4	1891.00	2426.13	1876.00		8.7554	3.29	6.7600	6.3800	4.9033
1990Q1	1790.00	2263.07	1767.00	65.76	6.6570	3.86	7.7700	7.2900	5.2303
1990Q2	1763.00	2205.21	1743.00	66.01	5.9625	3.03	8.3200	6.5000	4.6583
1990Q3	1759.00	2172.95	1740.00	65.79	8.8514	3.06	7.7700	6.0100	3.7881
1990Q4	1731.00	2111.03	1713.00	63.64	7.9205	3.50	6.9700	6.4300	4.6131
1991Q1	1697.00	2054.13	1676.00	61.26	6.1989	3.72	7.2200	6.5700	4.9414
1991Q2	1716.00	2065.68	1695.00	61.45	5.7335	2.87	7.8800	5.9600	4.4015
1991Q3	1747.00	2088.21	1730.00	62.53	6.4871	2.82	7.1500	5.9300	3.6092
1991Q4	1770.00	2098.95	1748.00	63.34	6.5093	3.40	6.9000	6.4600	5.0790
1992Q1	1847.00	2173.40	1819.00	62.36	6.0438	3.60	6.9400	6.4600	5.3640
1992Q2	1903.00	2225.05	1871.00	63.57	6.0807	3.28	9.0900	7.2400	4.6979
1992Q3	1952.00	2266.53	1922.00	64.74	6.4723	3.42	8.0900	6.7500	3.6714
1992Q4	2031.00	2343.45	2006.00	64.92	6.4354	3.89	7.8600	7.0000	5.2067
1993Q1	2050.00	2353.18	2037.00	66.10	6.2433	3.59	5.9100	5.6200	5.5017
1993Q2	2091.00	2384.86	2076.00	67.06	5.7852	3.91	8.6000	6.2200	4.7645
1993Q3	2139.00	2431.26	2124.00	67.85	5.6891	4.44	7.0900	5.9700	3.8236
1993Q4	2141.00	2420.77	2119.00	69.27	5.9403	3.72	8.1500	7.6800	5.4652
1994Q1	2071.00	2332.36	2057.00	70.80	5.7778	3.94	6.5700	6.3000	5.7675
1994Q2	2164.00	2423.89	2150.00	72.37	5.3049	3.38	9.4200	6.6300	5.2195
1994Q3	2170.00	2409.24	2158.00	73.56	5.4675	2.94	7.7600	6.2700	4.2329
1994Q4	2202.00	2433.90	2190.00	75.83	5.7926	3.09	7.3100	6.8600	4.8794
1995Q1	2124.00	2336.40	2121.00	77.34	5.6596	3.37	5.6500	5.4700	5.2841
1995Q2	2114.00	2312.61	2112.00	77.89	5.3862	3.38	8.1600	6.0300	4.7881
1995Q3	2103.00	2290.82	2100.00	78.69	5.4601	3.86	7.2400	5.6600	3.9488
1995Q4	2135.00	2316.00	2131.00	80.22	6.5831	3.31	7.0900	6.6700	5.1106
1996Q1	2198.00	2369.61	2191.00	80.77	7.1299	4.06	5.9400	5.7900	5.5996
1996Q2	2285.00	2447.72	2278.00	83.09	6.1768	4.30	8.4500	6.2900	4.9968
1996Q3	2365.00	2523.34	2360.00	85.04	7.3220	4.45	7.0500	5.8600	4.2826
1996Q4	2390.00	2533.07	2384.00	86.24	7.5436	4.12	9.1000	8.3900	5.3159
1997Q1	2442.00	2576.47	2441.00	88.28	7.0338	4.45	6.6200	6.5000	5.5646
1997Q2	2476.00	2607.39	2475.00	90.66	6.3245	3.72	9.0100	6.4700	4.7243
1997Q3	2505.00	2630.81	2504.00	93.83	6.5166	4.25	7.4700	6.1400	3.7229
1997Q4	2552.00	2671.24	2551.00	96.98	6.3984	3.90	8.1900	7.6000	4.8829
1998Q1	2690.00	2813.51	2688.00	99.01	6.0068	3.93	6.3800	6.1800	5.1071
1998Q2	2776.00	2898.58	2774.00	99.29	5.2089	3.53	9.0300	6.5900	4.6809
1998Q3	2909.00	3027.43	2906.00	100.06	5.2532	3.92	7.2900	5.9400	3.7677
1998Q4	3029.00	3140.72	3026.00	101.13	5.2311	3.54	7.4400	6.8900	4.6134
1999Q1	2999.00	3101.76	2990.00	102.18	5.1867	3.52	5.6700	5.4000	5.0460
1999Q2	3067.00	3151.49	3058.00	103.52	5.1498	3.81	8.8000	6.4100	4.6249
1999Q3	3118.00	3186.35	3109.00	104.21	6.4871	5.64	7.3800	6.2900	3.8324
1999Q4	3215.00	3266.02	3207.00	106.74	8.9327	4.64	9.0600	7.7900	6.0304
2000Q1	3418.00	3442.23	3417.00	108.77	8.6002	4.19	7.9400	6.8400	6.7178
2000Q2	3491.00	3498.80	3499.00	110.81	8.7110	4.54	12.4900	9.1600	5.9907
2000Q3	3517.00	3508.61	3517.00	111.60	9.7159	6.67	10.9900	8.7500	5.2864
2000Q4	3540.00	3515.85	3546.00	112.27	9.9671	6.94	11.9400	11.3200	11.2000
2001Q1	3534.00	3481.70	3530.00	110.80	9.3612	5.38	11.9900	11.6100	10.7200
2001Q2	3581.00	3505.77	3584.00	108.35	8.9548	4.37	16.6700	12.9300	8.2100
2001Q3	3624.00	3542.83	3627.00	104.37	8.6889	3.22	13.0000	9.9000	3.7100
2001Q4	3633.00	3546.57	3635.00	100.55	8.3638	2.83	9.4600	8.8800	7.2600
2002Q1	3732.00	3634.84	3749.00	99.43	8.1052	3.90	10.0500	9.2100	7.7100
2002Q2	3743.00	3620.45	3767.00	100.24	7.4919	4.29	12.2300	10.1000	5.9400
2002Q3	3725.00	3587.22	3731.00	100.88	8.2308	4.51	11.4100	9.0400	6.1500
2002Q4	3771.00	3616.64	3766.00	99.41	9.3982	4.94	9.8900	8.6200	7.9100
2003Q1	3738.00	3558.27	3740.00	99.19	9.7971	9.20	10.8700	10.7600	8.2300
2003Q2	3823.00	3633.34	3824.00	98.82	8.7701	4.63	16.9500	11.6600	11.0600
2003Q3	3933.00	3719.71	3933.00	100.50	8.8957	7.76	13.4700	10.1600	9.6500
2003Q4	3990.00	3761.45	3989.00	102.49	10.0705	8.56	13.6700	12.6100	9.2300
2004Q1	4086.00	3615.70	4064.00	103.71	9.8710	6.02	14.6200	13.1000	13.0700

C&I Var Index	38	39	40	41	42	43	44	45	46
C&I Var Name	PITP	TPTR	PINF	INDX	PRCO	PRCG	PRCR	PRCC	PRCI
Description	Personal Income, Total Proprietors Income,	Real Total Proprietors Income	Personal Income, Nonfarm Proprietors Income	Industrial Production Index, Total	New Hampshire #2 Heating Oil Production Price	New Hampshire Natual Gas City Gate Price	New Hampshire Residential Natural Gas Price	New Hampshire Commercial Natural Gas Price	New Hampshire Industrial Natural Gas Price
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	4258.00	3939.35	4255.00	105.50	10.3661	5.99	18.3500	14.3900	11.9800
2004Q3	4333.00	3994.14	4332.00	107.73	12.9225	7.63	16.3800	13.4100	11.3400
2004Q4	4364.00	3991.73	4364.00	108.05	12.8264	9.07	13.2700	12.4600	10.3600
2005Q1	4455.00	4052.36	4456.00	109.52	13.7869	8.21	14.6600	13.3800	12.7900
2005Q2	4566.00	4119.75	4570.00	110.23	14.7918	9.65	17.3000	13.1500	9.7300
2005Q3	4647.00	4154.82	4652.00	109.68	17.1782	12.75	18.5300	15.0300	11.9200
2005Q4	4703.00	4175.36	4707.00	111.33	16.2916	12.29	17.0100	16.3900	15.9200
2006Q1	4663.62	4121.45	4665.08	111.77		12.35			
2006Q2	4702.71	4138.13	4704.40	112.82		12.99			
2006Q3	4765.65	4180.99	4767.78	113.39		12.99			
2006Q4	4815.31	4207.65	4817.44	112.98		13.09			
2007Q1	4863.33	4231.71	4865.30	113.27		13.29			
2007Q2	4917.56	4261.43	4919.19	113.64		13.37			
2007Q3	4975.65	4293.18	4976.92	114.11		13.48			
2007Q4	5042.68	4330.57	5043.89	114.74		13.60			
2008Q1	5117.50	4373.14	5118.59	115.37		13.70			
2008Q2	5198.30	4422.85	5199.32	115.93		13.81			
2008Q3	5273.22	4466.69	5274.14	116.57		13.91			
2008Q4	5351.96	4514.42	5352.78	117.32		14.02			
2009Q1	5439.53	4568.05	5440.24	118.22		14.12			
2009Q2	5530.21	4625.43	5530.88	119.11		14.23			
2009Q3	5608.27	4671.88	5608.91	119.99		14.33			
2009Q4	5687.34	4719.03	5687.93	120.99		14.44			
2010Q1	5768.14	4764.74	5768.66	121.97		14.54			
2010Q2	5857.27	4817.95	5857.74	122.89		14.65			
2010Q3	5937.00	4862.41	5937.43	123.80		14.75			
2010Q4	6019.33	4907.41	6019.73	124.84		14.86			
2011Q1	6106.72	4955.44	6107.07	125.89		14.96			
2011Q2	6192.71	5002.16	6193.03	126.96		15.07			
2011Q3	6272.78	5042.72	6273.07	128.06		15.17			
2011Q4	6356.79	5085.93	6357.05	129.14		15.27			
2012Q1	6443.32	5130.81	6443.57	130.27		15.38			
2012Q2	6531.97	5176.09	6532.20	131.45		15.48			
2012Q3	6615.40	5216.64	6615.61	132.64		15.59			
2012Q4	6702.13	5259.00	6702.32	133.84		15.69			
2013Q1	6791.81	5303.00	6791.98	135.04		15.80			
2013Q2	6882.61	5347.69	6882.76	136.25		15.90			
2013Q3	6969.21	5389.21	6969.34	137.47		16.01			
2013Q4	7055.74	5430.55	7055.87	138.82		16.11			
2014Q1	7150.67	5477.24	7150.78	140.31		16.22			
2014Q2	7248.76	5525.74	7248.86	141.82		16.32			
2014Q3	7339.05	5568.48	7339.14	143.36		16.43			
2014Q4	7432.07	5613.15	7432.16	144.94		16.53			
2015Q1	7534.14	5663.88	7534.22	146.46		16.64			
2015Q2	7636.87	5714.21	7636.94	148.08		16.74			
2015Q3	7735.26	5760.91	7735.32	149.72		16.85			
2015Q4	7836.96	5810.46	7837.02	151.42		16.95			
2016Q1	7947.98	5865.76	7948.03	153.21		17.06			
2016Q2	8059.41	5920.37	8059.46	155.03		17.16			
2016Q3	8164.88	5969.97	8164.91	156.90		17.27			
2016Q4	8275.88	6022.97	8275.92	158.79		17.37			
2017Q1	8401.64	6082.48	8401.67	160.34		17.47			
2017Q2	8529.96	6142.61	8529.99	161.86		17.58			
2017Q3	8661.46	6204.03	8661.49	163.39		17.68			
2017Q4	8797.29	6267.67	8797.31	164.99		17.79			
2018Q1	8935.78	6332.55	8935.81	166.77		17.89			
2018Q2	9071.34	6394.43	9071.36	168.58		18.00			
2018Q3	9205.55	6454.14	9205.57	170.31		18.10			
2018Q4	9348.11	6518.43	9348.12	172.06		18.21			
2019Q1	9492.85	6583.22	9492.87	173.85		18.31			
2019Q2	9633.90	6644.53	9633.92	175.67		18.42			
2019Q3	9776.14	6705.97	9776.16	177.44		18.52			
2019Q4	9922.71	6769.54	9922.72	179.23		18.63			
2020Q1	10075.48	6837.05	10075.49	181.10		18.73			
2020Q2	10225.19	6901.27	10225.20	182.99		18.84			
2020Q3	10373.41	6963.08	10373.42	184.96		18.94			
2020Q4	10525.18	7025.68	10525.19	186.91		19.05			

C&I Var Index	47	48	49	50	51	52	53	54	55
C&I Var Name	PRCCI	EGYO	EGYG	EGYC	EGYI	RPRC	RPRI	REGC	REGI
Description	New Hampshire Commercial & Industrial Natural Gas Price	New Hampshire #2 Heating Oil Consumption	New Hampshire Natural Gas Consumption by All	New Hampshire Commercial Natural Gas Consumption	New Hampshire Industrial Natural Gas Consumption	Price Ratio: Commercial Ntural Gas Price : #2 Heating Oil Price	Price Ratio: Industrial Ntural Gas Price : #2 Heating Oil Price	Energy Consumption Ratio: Commercial Natural Gas : #2 Heating Oil	Energy Consumption Ratio: Industrial Natural Gas : #2 Heating Oil
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	5.8958	1897.82	1197.21	400.48	312.29	0.80	0.66	6.33	4.94
1984Q2	5.1528	1113.54	519.21	117.59	291.30	0.85	0.62	3.27	8.11
1984Q3	4.8434	1365.71	643.30	202.94	238.63	0.81	0.50	4.61	5.42
1984Q4	5.6678	3203.85	2146.38	804.03	537.21	0.85	0.63	7.78	5.20
1985Q1	5.5530	1455.64	1351.51	479.10	382.57	0.80	0.66	9.87	7.88
1985Q2	4.8874	806.84	623.48	146.76	362.62	0.90	0.65	5.64	13.93
1985Q3	4.5965	1611.15	726.49	243.21	278.97	0.76	0.47	4.68	5.37
1985Q4	5.8895	2713.79	2110.15	725.80	510.54	0.86	0.64	8.29	5.83
1986Q1	5.7364	1776.01	1298.05	427.27	338.84	1.11	0.93	7.22	5.72
1986Q2	5.0985	890.33	576.83	131.86	315.81	1.34	0.99	4.59	11.00
1986Q3	4.7800	2097.02	684.44	216.81	246.74	1.26	0.79	3.21	3.65
1986Q4	5.2409	3760.20	2235.85	751.32	520.69	1.04	0.77	6.19	4.29
1987Q1	5.0845	2758.21	1376.75	442.48	351.35	1.00	0.85	4.81	3.82
1987Q2	4.5495	1374.52	597.69	137.60	325.18	1.01	0.75	3.10	7.33
1987Q3	4.2508	2576.17	724.42	224.19	259.67	0.92	0.58	2.70	3.12
1987Q4	5.1312	7012.30	2398.33	821.74	556.98	0.95	0.69	3.63	2.46
1988Q1	4.9105	2622.59	1474.62	483.10	377.73	0.90	0.77	5.53	4.32
1988Q2	4.3819	2183.03	641.68	151.26	347.95	0.95	0.70	2.15	4.94
1988Q3	4.0819	2323.17	777.82	243.84	283.30	0.96	0.61	3.25	3.78
1988Q4	5.5461	4920.74	2454.40	842.00	568.40	1.01	0.75	5.30	3.58
1989Q1	5.6760	3823.24	1670.19	551.00	433.19	1.03	0.79	4.32	3.40
1989Q2	4.8579	1022.08	683.90	154.00	374.90	1.07	0.75	4.67	11.37
1989Q3	4.6729	4834.72	804.53	248.00	282.53	0.98	0.57	1.59	1.81
1989Q4	5.7905	5439.75	2614.37	899.00	597.37	0.73	0.56	5.12	3.40
1990Q1	6.3861	3073.70	1578.09	518.00	405.09	1.10	0.79	5.06	3.95
1990Q2	5.1945	1497.87	670.47	153.00	372.47	1.09	0.78	3.17	7.71
1990Q3	4.8267	2467.50	769.90	265.00	301.90	0.68	0.43	3.33	3.79
1990Q4	5.6954	5069.26	2239.51	794.67	539.44	0.81	0.58	4.86	3.30
1991Q1	5.8442	2656.29	1472.14	484.17	389.25	1.06	0.80	5.47	4.40
1991Q2	4.8571	1536.89	670.34	154.68	374.38	1.04	0.77	3.12	7.55
1991Q3	4.7066	3730.83	790.03	256.04	285.45	0.91	0.56	2.13	2.37
1991Q4	5.9003	7026.57	2563.66	910.73	620.72	0.99	0.78	4.02	2.74
1992Q1	5.9735	3052.99	1896.90	629.01	502.02	1.07	0.89	6.18	4.93
1992Q2	5.4396	1496.61	771.86	178.78	433.92	1.19	0.77	3.70	8.99
1992Q3	5.1142	3049.87	916.66	294.81	334.26	1.04	0.57	3.00	3.40
1992Q4	6.2780	4797.80	2710.54	993.00	669.28	1.09	0.81	6.42	4.32
1993Q1	5.5661	2873.12	1844.28	611.10	511.78	0.90	0.88	6.38	5.34
1993Q2	5.1480	1600.67	820.59	177.01	494.89	1.08	0.82	3.43	9.58
1993Q3	4.7476	2308.48	1097.95	331.62	438.67	1.05	0.67	4.45	5.89
1993Q4	6.7546	6864.61	3459.99	1260.98	905.08	1.29	0.92	5.69	4.09
1994Q1	6.0607	2439.88	1719.34	580.75	473.87	1.09	1.00	7.14	5.83
1994Q2	5.5952	902.08	785.91	173.00	476.44	1.25	0.98	5.94	16.37
1994Q3	5.1437	2161.21	957.73	305.11	377.34	1.15	0.77	4.38	5.41
1994Q4	6.0477	4623.26	2671.03	978.32	680.16	1.18	0.84	6.56	4.56
1995Q1	5.3867	2795.56	1833.73	632.29	513.16	0.97	0.93	6.79	5.51
1995Q2	5.1364	949.07	829.71	187.99	482.18	1.12	0.89	6.14	15.75
1995Q3	4.7279	2341.63	886.60	285.43	341.51	1.04	0.72	3.78	4.52
1995Q4	6.0437	5794.28	3136.33	1163.13	780.65	1.01	0.78	6.22	4.18
1996Q1	5.7060	2448.81	1881.34	661.26	522.40	0.81	0.79	8.10	6.40
1996Q2	5.3685	967.95	780.42	180.23	446.84	1.02	0.81	5.77	14.31
1996Q3	4.9922	2479.67	1112.44	360.14	440.44	0.80	0.58	4.50	5.51
1996Q4	7.1715	5800.58	2918.69	1121.38	736.34	1.11	0.70	5.99	3.94
1997Q1	6.1300	3232.05	1966.49	738.80	483.45	0.92	0.79	6.86	4.49
1997Q2	5.2943	1283.47	821.65	215.94	445.47	1.02	0.75	5.22	10.76
1997Q3	5.0009	2467.08	1103.25	410.52	365.91	0.94	0.57	5.16	4.60
1997Q4	6.5438	5756.94	3049.76	1167.30	742.33	1.19	0.76	6.29	4.00
1998Q1	5.7091	2528.39	1753.26	623.07	487.39	1.03	0.85	7.39	5.78
1998Q2	5.3234	1052.29	840.24	227.85	449.10	1.27	0.90	6.71	13.23
1998Q3	4.8566	2396.59	1033.17	370.76	368.90	1.13	0.72	4.80	4.77
1998Q4	6.0642	5505.62	3303.81	1311.64	746.58	1.32	0.88	7.39	4.20
1999Q1	5.2489	2506.06	1820.87	658.31	490.18	1.04	0.97	7.88	5.87
1999Q2	5.1645	1132.84	799.17	195.69	451.67	1.24	0.90	5.36	12.36
1999Q3	5.1123	2295.48	1099.70	403.23	371.01	0.97	0.59	5.45	5.01
1999Q4	7.0037	6590.63	3728.70	1334.53	1078.20	0.87	0.68	6.28	5.07
2000Q1	6.7788	2954.73	2046.72	707.05	707.91	0.80	0.78	7.18	7.19
2000Q2	6.9012	1185.29	1093.48	262.93	652.29	1.05	0.69	6.88	17.06
2000Q3	6.8022	2691.13	1251.81	416.96	535.80	0.90	0.54	4.80	6.17
2000Q4	11.2703	6593.57	3171.00	1122.96	793.12	1.14	1.12	5.28	3.73
2001Q1	11.2299	3154.50	2280.00	885.66	660.28	1.24	1.15	8.42	6.28
2001Q2	8.9098	1374.94	1003.00	126.04	724.10	1.44	0.92	2.84	16.33
2001Q3	5.3240	2444.00	1589.00	259.90	736.84	1.14	0.43	3.30	9.35
2001Q4	8.2688	5340.31	2917.00	1162.59	704.32	1.06	0.87	6.75	4.09
2002Q1	8.3944	2766.74	2179.00	700.30	834.57	1.14	0.95	7.59	9.05
2002Q2	7.1562	1160.95	1657.00	399.24	966.35	1.35	0.79	10.66	25.80
2002Q3	8.0171	2913.50	1038.00	368.60	201.93	1.10	0.75	3.92	2.15
2002Q4	8.2462	7093.70	5812.00	1791.72	1991.73	0.92	0.84	7.83	8.70
2003Q1	9.7893	3331.53	3059.00	863.20	537.32	1.10	0.84	7.77	4.84
2003Q2	11.3524	1073.68	4097.00	302.76	318.51	1.33	1.26	8.74	9.20
2003Q3	9.9221	2564.00	4892.00	434.60	379.96	1.14	1.08	5.25	4.59
2003Q4	11.4947	7049.22	5504.00	1422.79	700.72	1.25	0.92	6.26	3.08
2004Q1	13.0869	2655.48	6262.00	843.95	651.65	1.33	1.32	9.53	7.36

C&I Var Index	47	48	49	50	51	52	53	54	55
C&I Var Name	PRCCI	EGYO	EGYG	EGYC	EGYI	RPRC	RPRI	REGC	REGI
Description	New Hampshire Commercial & Industrial Natural Gas Price	New Hampshire #2 Heating Oil Consumption	New Hampshire Natural Gas Consumption by All	New Hampshire Commercial Natural Gas Consumption	New Hampshire Industrial Natural Gas Consumption	Price Ratio: Commercial Ntural Gas Price : #2 Heating Oil Price	Price Ratio: Industrial Ntural Gas Price : #2 Heating Oil Price	Energy Consumption Ratio: Commercial Natural Gas : #2 Heating Oil	Energy Consumption Ratio: Industrial Natural Gas : #2 Heating Oil
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	12.8427	891.17	4222.00	297.19	533.06	1.39	1.16	10.34	18.54
2004Q3	12.1901	2353.38	3269.00	416.32	597.45	1.04	0.88	5.48	7.87
2004Q4	11.8037	5787.99	6924.00	1596.99	725.91	0.97	0.81	8.55	3.89
2005Q1	13.1597	2004.20	5693.00	910.54	542.47	0.97	0.93	13.63	8.12
2005Q2	11.1381	956.62	6050.00	319.41	456.36	0.89	0.66	10.35	14.79
2005Q3	13.3308	1764.72	6050.00	428.82	516.47	0.87	0.69	7.53	9.07
2005Q4	16.2564	3942.71	6050.00	1393.65	553.24	1.01	0.98	10.96	4.35
2006Q1									
2006Q2									
2006Q3									
2006Q4									
2007Q1									
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2019Q4									
2020Q1									
2020Q2									
2020Q3									
2020Q4									

C&I Var Index	56	57	58	59	60	61	62	63	64
C&I Var Name	REVC	REVI	REVCI	RVNC	RVNI	RVNCI	CHGC	CHGI	CHGCI
Description	Revenue to Commercial Customers	Revenue to Industrial Customers	Revenue to C & I Customers	Revenue (Normal)to Commercial Customers	Revenue (Normal)to Industrial Customers	Revenue (Normal)to C & I Customers	Company Charge to Commercial Customers	Company Charge to Industrial Customers	Company Charge to C & I Customers
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
1984Q1	8530032.00	481649.00	9011681.00	9009405.69	513082.79	9522488.48	7.16	18.01	7.40
1984Q2	4110927.00	236149.00	4347076.00	3519612.68	219244.86	3738857.55	7.53	15.42	7.74
1984Q3	1956475.00	128689.00	2085164.00	1653774.84	114873.48	1768648.32	7.89	10.16	8.00
1984Q4	5080530.00	348775.00	5429305.00	7210195.08	407300.57	7617495.65	8.12	15.72	8.38
1985Q1	9274260.00	468728.00	9742988.00	10117936.76	542838.19	10660774.95	7.70	18.64	7.92
1985Q2	3943887.00	159204.00	4103091.00	3451308.62	139575.69	3590884.31	7.74	10.52	7.82
1985Q3	1890914.00	196080.00	2086994.00	2014245.64	235878.11	2250123.75	7.96	18.52	8.41
1985Q4	5078699.00	261633.00	5340332.00	6898144.44	290839.07	7188983.51	8.01	16.27	8.22
1986Q1	9412596.00	438766.00	9851362.00	9845262.51	493766.59	10339029.10	7.49	14.63	7.65
1986Q2	3939208.00	170557.00	4109765.00	3418954.75	233567.32	3652522.07	7.64	10.26	7.73
1986Q3	2026206.00	125137.00	2151343.00	2253196.01	149826.02	2403022.03	8.40	9.41	8.45
1986Q4	5277100.00	247249.00	5524349.00	7340761.15	333564.70	7674325.85	6.68	5.98	6.65
1987Q1	9488498.00	382142.00	9870640.00	9279028.43	361690.85	9640719.28	6.53	5.59	6.49
1987Q2	3859979.00	160675.00	4020654.00	3195869.70	130877.98	3326747.68	6.43	5.57	6.39
1987Q3	1635077.00	109275.00	1744352.00	1518009.79	138927.14	1656936.93	5.70	9.51	5.84
1987Q4	4511707.00	535875.98	5047582.98	6039969.40	640227.26	6680196.66	5.62	5.16	5.57
1988Q1	8986120.00	702507.85	9688627.85	9206455.37	731751.07	9938206.45	5.76	5.40	5.74
1988Q2	3954112.00	359186.73	4313298.73	2991148.16	291380.99	3282529.15	5.59	5.06	5.54
1988Q3	1551940.00	222167.97	1774107.97	1666927.74	235499.30	1902427.04	5.50	5.03	5.44
1988Q4	5911419.00	582995.76	6494414.76	7570050.95	699708.85	8269759.80	6.42	6.00	6.38
1989Q1	10877850.00	870476.04	11748326.04	11208860.47	882651.43	12091511.89	6.63	6.10	6.59
1989Q2	4638418.00	453010.39	5091428.39	3381865.68	430928.33	3812794.00	6.31	5.66	6.24
1989Q3	1766740.00	409252.64	2175992.64	1843763.64	458493.90	2302257.55	6.39	5.33	6.16
1989Q4	6100503.00	1356672.13	7457175.13	7599820.50	1682822.33	9282642.83	6.68	6.63	6.67
1990Q1	11094768.00	2329411.40	13424179.40	10935905.73	2249919.90	13185825.63	8.03	6.80	7.79
1990Q2	4956307.00	1023423.80	5979730.80	3609714.88	770626.58	4380341.46	8.18	6.65	7.87
1990Q3	1974924.00	473471.75	2448395.75	2089091.14	484125.12	2573216.26	7.72	6.26	7.39
1990Q4	5459232.00	1164270.62	6623502.62	7899781.81	1612698.44	9512480.25	7.94	6.48	7.64
1991Q1	10473479.00	2157055.55	12630534.55	10951863.71	2242551.89	13194415.60	7.82	6.50	7.56
1991Q2	4217194.00	915964.52	5133158.52	3374260.98	704555.14	4078816.11	7.68	6.17	7.36
1991Q3	1832460.00	489777.62	2322237.62	1971376.76	520315.26	2491692.02	7.22	5.73	6.84
1991Q4	5772681.00	1241431.64	7014112.64	8043808.28	1675775.20	9719583.48	7.87	6.31	7.54
1992Q1	11672669.00	2436831.00	14109500.00	11781939.50	2475027.34	14256966.84	7.85	6.43	7.56
1992Q2	5728236.00	1375418.35	7103654.35	3846890.61	989190.45	4836081.06	8.33	6.68	7.95
1992Q3	2474351.00	725874.64	3200225.64	2713020.23	764537.81	3477558.04	8.79	7.06	8.33
1992Q4	7908712.25	1705024.73	9613736.99	8224458.91	1997147.73	10221606.64	9.55	7.18	9.02
1993Q1	11129201.07	2348155.07	13477356.15	11033594.99	2769521.95	13803116.94	6.86	5.50	6.58
1993Q2	2655190.86	591050.80	3246241.66	2669825.30	830549.08	3500374.38	3.93	2.80	3.66
1993Q3	1706047.61	378598.78	2084646.38	1662081.69	609325.90	2271407.59	5.80	3.16	5.04
1993Q4	7364960.05	1624578.74	8989538.79	7276911.03	2000488.03	9277399.06	8.85	5.94	8.13
1994Q1	13024970.90	2672998.99	15697969.89	12042974.88	3163855.49	15206830.37	7.00	5.33	6.65
1994Q2	2942261.39	620861.58	3563122.97	2926857.53	956520.42	3883377.95	4.08	2.65	3.73
1994Q3	1750791.52	391637.11	2142428.63	1771263.22	709059.19	2480322.41	5.88	2.84	4.92
1994Q4	7085341.22	1432003.52	8517344.74	7765076.06	1858196.18	9623272.24	9.31	6.65	8.16
1995Q1	10665648.35	2041557.58	12707205.93	11712899.71	2402561.66	14115461.37	6.67	5.75	6.12
1995Q2	2808664.24	592202.33	3464518.12	2755274.63	724696.49	3569107.94	3.95	3.79	3.64
1995Q3	1772632.53	345424.59	2162852.16	1683527.11	465728.62	2215953.43	6.16	4.24	4.99
1995Q4	8178769.59	1288365.70	9642421.48	8016359.70	1653849.31	9929648.08	8.82	6.26	7.68
1996Q1	12398027.75	2329901.63	14977283.55	12345538.95	2663534.65	15400489.47	6.90	5.83	6.36
1996Q2	2921504.45	519833.89	3505060.56	2776234.94	789524.54	3676291.61	3.90	2.64	3.30
1996Q3	1606480.80	286285.43	1937540.21	1629728.99	545493.90	2261305.73	5.55	2.26	3.81
1996Q4	9699166.09	1643645.88	11516466.17	9530772.72	2016396.45	11847682.52	9.00	6.37	7.77
1997Q1	13592366.81	2611413.68	16501021.50	14558595.10	2911209.68	17915308.27	7.09	6.65	6.59
1997Q2	3958586.76	658513.04	4724575.20	3622247.36	872558.49	4622269.23	4.26	2.94	3.60
1997Q3	1977959.27	369335.96	2443521.74	1985690.64	478730.45	2591775.43	5.90	3.57	4.01
1997Q4	9076326.93	1575728.95	11099546.95	9016097.00	1598731.00	11186425.00	8.05	7.24	6.70
1998Q1	13427054.81	-1943144.58	12238216.29	15336701.00	2341547.00	18600276.00	7.21	-6.48	4.77
1998Q2	4341970.10	2067624.77	6633144.92	4761875.00	752452.00	5816200.00	5.52	15.95	5.34
1998Q3	2524436.19	312934.87	3028392.84	2390445.00	508322.00	3175383.00	7.42	3.59	4.10
1998Q4	6504335.82	1189905.47	8287504.59	6955681.00	1066514.00	8810180.00	6.87	7.48	5.43
1999Q1	14234201.39	1892380.38	17217735.98	15037313.00	2049899.00	18405438.00	6.87	6.43	5.91
1999Q2	4061204.07	415850.68	4796632.74	4189213.00	526367.00	5127797.00	5.16	3.98	3.70
1999Q3	1978028.45	122367.46	2373088.02	2011934.00	246960.00	2613256.00	6.35	2.87	3.36
1999Q4	7152192.46	18684.51	8026263.04	7627801.00	1013219.00	9694606.00	7.48	0.14	4.99
2000Q1	17836986.76	10926.14	19134850.99	18310661.00	2535907.00	22356862.00	8.02	0.03	6.08
2000Q2	5406250.54	406092.03	6175544.44	5569347.00	720543.00	6737924.00	6.38	3.47	4.53
2000Q3	2755761.62	200107.26	3340873.87	2751833.22	367506.37	3663483.31	8.00	3.59	4.37
2000Q4	10746342.42	1674055.41	13086310.93	10580029.84	1631628.33	12969204.63	10.12	9.63	7.40
2001Q1	8296993.00	1098117.00	11179590.00	7516127.00	981737.00	10282344.00	3.61	3.26	3.43
2001Q2	2137160.00	1276213.00	3917393.00	1991694.00	1183105.00	3678448.00	2.78	1.86	2.37
2001Q3	833616.00	1011165.00	1866347.00	818038.00	988920.00	1828524.00	6.86	1.99	2.71
2001Q4	1385175.00	1902587.00	3338267.00	1365359.00	1863631.00	3270348.00	3.86	1.80	2.13
2002Q1	2678225.00	3709825.00	6455961.00	3002191.19	4114224.37	7182324.81	2.95	2.08	2.26
2002Q2	1514479.00	2241022.00	3850264.00	1486370.46	2080556.27	3644103.27	3.82	2.04	2.13
2002Q3	881684.49	696723.49	1623020.11	881992.92	717021.01	1643626.06	6.39	1.80	2.17
2002Q4	1796302.08	2457487.70	4337975.51	1772497.58	2426988.99	4283333.22	3.54	2.19	2.28
2003Q1	3474680.00	4626173.00	8165509.00	3616955.00	4815945.00	8497446.00	2.72	1.96	2.16
2003Q2	1672829.00	2367058.00	4105371.00	1557181.00	2181177.00	3803121.00	3.60	2.08	2.28
2003Q3	919826.00	1007638.00	1984190.00	920378.00	1006795.00	1983899.00	6.34	2.14	2.32
2003Q4	1656922.00	2227590.00	3952563.00	1503276.00	1994115.00	3564906.00	3.53	2.02	2.17
2004Q1	3589389.00	4577768.00	8235446.00	3875044.00	4970838.00	8914729.00	2.74	1.99	2.18

C&I Var Index	56	57	58	59	60	61	62	63	64
C&I Var Name	REVC	REVI	REVCI	RVNC	RVNI	RVNCI	CHGC	CHGI	CHGCI
Description	Revenue to Commercial Customers	Revenue to Industrial Customers	Revenue to C & I Customers	Revenue (Normal)to Commercial Customers	Revenue (Normal)to Industrial Customers	Revenue (Normal)to C & I Customers	Company Charge to Commercial Customers	Company Charge to Industrial Customers	Company Charge to C & I Customers
Start Year	1984	1984	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4	4	4
2004Q2	1594858.00	2135568.00	3805728.00	1544001.00	2072689.00	3691957.00	3.77	2.15	2.33
2004Q3	934991.00	1062865.00	2056203.00	823815.00	838191.00	1706080.00	6.28	2.14	2.31
2004Q4	1621664.00	2136591.00	3821510.00	1488701.00	1936810.00	3488312.00	3.59	2.07	2.25
2005Q1	3433320.00	4433432.00	7940614.00	3726534.00	4830335.00	8630083.00	2.79	2.03	2.21
2005Q2	1681238.00	2348065.00	4098684.00	1602593.00	2228282.00	3900113.00	3.70	2.15	2.33
2005Q3	952981.00	1052742.00	2064236.00	953248.00	1047799.00	2059563.00	6.54	2.11	2.90
2005Q4	1707728.00	2274194.00	4027184.00	1565897.00	2080850.00	3691494.00	3.57	2.04	2.53
2006Q1									
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C&I Var Index	65	66	67	68	69	70	71
C&I Var Name	CHNC	CHNI	CHNCI	CDDN	CDDA	BDDN	BDDA
Description	Company charge (Normal)to Commercial Customers	Company charge (Normal)to Industrial Customers	Company charge (Normal)to C & I Customers	Normal Callendar Degree Days	Actual Callendar Degree Days	Normal Billing Degree Days	Actual Billing Degree Days
Start Year	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4
1984Q1	7.40	19.19	7.66	3652	3644	3826	3718
1984Q2	6.68	14.31	6.89	1032	1074	1494	1599
1984Q3	6.67	9.07	6.78	286	284	227	208
1984Q4	10.76	18.36	11.00	2611	2310	2106	1893
1985Q1	8.01	21.59	8.27	3652	3507	3813	3593
1985Q2	6.47	9.22	6.54	1032	980	1488	1378
1985Q3	8.41	22.28	8.99	286	213	225	183
1985Q4	10.67	18.08	10.85	2611	2596	2101	2016
1986Q1	7.53	16.47	7.73	3652	3418	3803	3628
1986Q2	6.12	14.06	6.35	1032	906	1477	1290
1986Q3	9.48	11.27	9.58	286	359	229	304
1986Q4	9.38	8.07	9.31	2611	2566	2103	2137
1987Q1	6.14	5.29	6.10	3652	3528	3793	3613
1987Q2	5.08	4.54	5.05	1032	915	1471	1346
1987Q3	5.24	12.09	5.50	286	308	230	246
1987Q4	7.47	6.16	7.32	2611	2564	2103	2096
1988Q1	5.78	5.62	5.76	3652	3601	3781	3685
1988Q2	4.17	4.11	4.17	1032	1017	1465	1434
1988Q3	5.95	5.33	5.87	286	298	231	257
1988Q4	8.28	7.20	8.17	2611	2680	2108	2145
1989Q1	6.50	6.19	6.47	3652	3415	3773	3549
1989Q2	4.66	5.38	4.73	1032	1002	1458	1473
1989Q3	6.56	5.97	6.43	286	228	227	184
1989Q4	8.86	8.23	8.74	2614	2988	2118	2253
1990Q1	7.54	6.22	7.27	3642	3175	3748	3528
1990Q2	5.91	4.96	5.71	1032	1021	1460	1454
1990Q3	8.12	6.42	7.74	285	220	226	162
1990Q4	10.26	8.07	9.80	2629	2195	2108	1762
1991Q1	7.55	6.28	7.30	3620	3298	3717	3376
1991Q2	5.52	4.36	5.28	1030	761	1440	1179
1991Q3	7.73	5.82	7.23	282	264	225	174
1991Q4	10.34	8.08	9.86	2645	2408	2102	1919
1992Q1	7.63	6.31	7.36	3651	3479	3706	3552
1992Q2	5.89	5.03	5.69	1026	1078	1437	1568
1992Q3	9.65	7.40	9.05	280	288	223	232
1992Q4	10.21	8.63	9.86	2605	2682	2088	2189
1993Q1	6.89	6.57	6.82	3606	3711	3710	3775
1993Q2	3.93	3.92	3.93	1025	907	1434	1396
1993Q3	5.79	4.99	5.55	275	250	223	178
1993Q4	8.87	7.43	8.52	2605	2628	2093	2154
1994Q1	7.00	6.75	6.95	3606	4027	3734	4105
1994Q2	4.08	4.10	4.08	1025	956	1428	1442
1994Q3	5.86	5.08	5.61	275	265	221	185
1994Q4	9.32	8.16	8.46	2605	2237	2071	1813
1995Q1	6.69	6.22	6.23	3606	3265	3717	3348
1995Q2	3.94	4.70	3.81	1025	1052	1428	1476
1995Q3	6.01	5.78	5.21	275	280	217	175
1995Q4	8.84	8.19	8.06	2599	2613	2072	2093
1996Q1	6.90	6.69	6.57	3651	3634	3717	3741
1996Q2	3.90	4.13	3.62	1019	1037	1428	1552
1996Q3	5.54	4.24	4.38	282	198	217	140
1996Q4	8.97	7.90	8.10	2594	2553	2072	2120
1997Q1	7.10	6.99	6.72	3617	3440	3703	3418
1997Q2	4.26	4.18	3.79	1023	1166	1432	1667
1997Q3	5.91	4.77	4.22	275	214	210	165
1997Q4	8.04	7.38	6.79	2603	2556	2054	2077
1998Q1	7.20	6.94	6.45	3602	2981	3669	3115
1998Q2	5.51	5.55	4.38	1020	831	1448	1221
1998Q3	7.36	5.72	4.34	274	164	205	138
1998Q4	6.86	6.38	5.45	2603	2292	2053	1842
1999Q1	6.87	6.59	6.01	3504	3342	3617	3394
1999Q2	5.16	4.90	3.86	984	896	1429	1341
1999Q3	6.34	5.74	3.66	257	168	199	133
1999Q4	7.49	7.13	5.72	2528	2345	2033	1862
2000Q1	8.02	7.64	6.93	3495	3344	3599	3480
2000Q2	6.34	5.94	4.80	979	997	1428	1356
2000Q3	8.00	6.68	4.78	251	241	194	193
2000Q4	10.09	9.51	7.40	2529	2614	2033	2044
2001Q1	3.33	2.88	3.21	3480	3551	3588	3679
2001Q2	2.65	1.64	2.22	977	880	1422	1401
2001Q3	6.85	1.93	2.02	248	158	192	113
2001Q4	3.34	1.58	1.86	2513	2082	2018	1653
2002Q1	2.87	2.01	2.19	3481	3013	3584	3045
2002Q2	3.69	1.89	2.03	979	992	1428	1399
2002Q3	6.60	1.58	1.76	244	111	189	130
2002Q4	3.58	2.19	2.29	2485	2578	1994	2016
2003Q1	2.69	1.95	2.14	3432	3815	3533	3913
2003Q2	3.79	2.12	2.33	975	1072	1420	1540
2003Q3	6.34	2.14	2.32	236	111	183	102
2003Q4	3.79	2.07	2.22	2503	2371	2004	1852
2004Q1	2.68	1.96	2.15	3459	3718	3563	3809

C&I Var Index	65	66	67	68	69	70	71
C&I Var Name	CHNC	CHNI	CHNCI	CDDN	CDDA	BDDN	BDDA
Description	Company charge (Normal)to Commercial Customers	Company charge (Normal)to Industrial Customers	Company charge (Normal)to C & I Customers	Normal Callendar Degree Days	Actual Callendar Degree Days	Normal Billing Degree Days	Actual Billing Degree Days
Start Year	1984	1984	1984	1984	1984	1984	1984
Start Period	4	4	4	4	4	4	4
Period / Year	4	4	4	4	4	4	4
Period / Cycle	4	4	4	4	4	4	4
2004Q2	3.86	2.16	2.35	977	897	1425	1331
2004Q3	5.54	1.70	1.92	231	133	180	119
2004Q4	3.82	2.13	2.30	2493	2394	1997	1868
2005Q1	2.72	1.99	2.17	3463	3581	3567	3636
2005Q2	3.84	2.19	2.37	968	977	1412	1466
2005Q3	6.53	2.12	2.91	224	75	175	80
2005Q4	3.81	2.08	2.62	2497	2362	1995	1792
2006Q1				3464			
2006Q2				969			
2006Q3				224			
2006Q4				2497			
2007Q1				3464			
2007Q2				969			
2007Q3				224			
2007Q4				2497			
2008Q1				3464			
2008Q2				969			
2008Q3				224			
2008Q4				2497			
2009Q1				3464			
2009Q2				969			
2009Q3				224			
2009Q4				2497			
2010Q1				3464			
2010Q2				969			
2010Q3				224			
2010Q4				2497			
2011Q1				3464			
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2014Q3				224			
2014Q4				2497			
2015Q1				3464			
2015Q2				969			
2015Q3				224			
2015Q4				2497			
2016Q1				3464			
2016Q2				969			
2016Q3				224			
2016Q4				2497			
2017Q1				3464			
2017Q2				969			
2017Q3				224			
2017Q4				2497			
2018Q1				3464			
2018Q2				969			
2018Q3				224			
2018Q4				2497			
2019Q1				3464			
2019Q2				969			
2019Q3				224			
2019Q4				2497			
2020Q1				3464			
2020Q2				969			
2020Q3				224			
2020Q4				2497			

ENERGYNORTH NATURAL GAS, INC.

(d/b/a KeySpan Energy Delivery New England)

INTEGRATED RESOURCE PLAN

(November 1, 2006 – October 31, 2011)

DG 06-105

Appendix B

KEYSPAN

Energy Delivery

Via Hand Delivery

December 8, 2005

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301

Re: DG 04-133/DG 04-175; EnergyNorth Natural Gas, Inc. d/b/a
KeySpan Energy Delivery New England

Dear Ms. Howland:

Enclosed for filing with the Commission are an original and eight copies of KeySpan Energy Delivery New England's Portfolio Management Plan. This Plan is being filed pursuant to the settlement agreement approved by the Commission in its Order No. 24,531 in dockets DG -04-133 and DG 04-175. An electronic copy of the filing was provided by e-mail to the librarian.

Sincerely,

Thomas P. O'Neill
Enclosures
Cc: F. Anne Ross, Esq.
Steven V. Camerino, Esq.
Jennifer Feinstein
Elizabeth Arangio
Ann Leary

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I. INTRODUCTION

This Portfolio Management Plan (the "Plan") is filed with the New Hampshire Public Utilities Commission ("Commission") by EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England ("EnergyNorth" or the "Company")[1] in compliance with the New Hampshire Public Utilities Commission's ("Commission") Order No. 24,531 dated October 21, 2005 in Dockets DG 04-133 and 04-175.

In Order No. 24,531, the Commission approved a settlement agreement between EnergyNorth, the Commission Staff and the Office of the Consumer Advocate ("OCA") with regard to the Company's Integrated Resource Plan for the period November 1, 2004 through October 31, 2009 (the "IRP"). Among other things, under the settlement agreement, EnergyNorth agreed to file with the Commission a detailed plan of how the Company will manage its gas resources effective with the April 1, 2006 expiration of its Gas Resource Portfolio Management and Gas Sales Agreement with Merrill Lynch Commodities, LLC. ("Merrill Lynch").

In accordance with the terms of the approved settlement, this Plan discusses the Company's plans with respect to, (i) daily forecasting, (ii) nominating, scheduling and confirming city gate deliveries and storage injections, (iii) reconciling supply invoices, (iv) pursuing capacity release and off-system sales opportunities, (v) supply balancing on the Tennessee Gas Pipeline system

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[1] EnergyNorth is a wholly owned subsidiary of KeySpan New England LLC., which is itself a wholly owned subsidiary of KeySpan Corporation. KeySpan Corporation is a public utility holding company headquartered in Brooklyn N.Y. Under the KeySpan holding company structure, many of the functions that are described in this document are performed by employees of KeySpan shared services organizations on behalf of EnergyNorth.

(vi) contracting for seasonal supplemental supplies and (vii) the economic operation of peaking facilities.

II. SUMMARY OF THE MERRILL LYNCH AGREEMENT

By contract, Merrill Lynch (1) manages certain of the Company's upstream interstate gas supply, transportation and underground storage assets and (2) provides the citygate gas supply requirements of the Company's firm sales customers. The Company retains the management of its supplemental resources.

Gas supplies delivered by Merrill Lynch to meet the Company's firm sales requirements and storage refill requirements are paid for by EnergyNorth in accordance with a tiered pricing hierarchy. The pricing hierarchy is intended to mimic the dispatch order the Company would employ if it were managing the assets on its own. The Company is responsible for paying all demand costs associated with its pipeline and underground storage resources. Commodity charges for citygate sales service are tied to market indices, which correlate to receipt points in the Company's portfolio.

With the expiration of the agreement with Merrill Lynch effective April 1, 2006, the Company plans to insource the management of its resource portfolio whereby the role of Merrill Lynch, with regards to management of the Company's upstream assets and commodity purchasing, will be assumed by the Company's Regulated Gas Transactions Group located in Hicksville, NY.[2] This

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2 Commodity supplies will be priced based on how they are actually dispatched.

group is also responsible for managing the regulated gas transactions for KeySpan Corporation's two New York-based gas utilities: KeySpan Energy Delivery New York (KED-NY) and KeySpan Energy Delivery Long Island (KED-LI).

III. ORGANIZATIONAL STRUCTURE

Implementation of the Company's Portfolio Management Plan will involve the close coordination of four groups within KeySpan's Asset Optimization Group; the Gas Supply Planning Group, currently led by Elizabeth Arangio, the Load Forecasting Group, currently led by Leo Silvestrini, the Regulated Gas Transactions Group, currently led by Mark Leippert and the Gas Contracting Group currently led by John Allocca.[3] Currently, all day to day activity pertaining to the EnergyNorth portfolio is performed by the Gas Supply Planning Group in combination with Merrill Lynch. However, as noted above, effective April 1, 2006 the activities now performed by Merrill Lynch will become the responsibility of the Regulated Gas Transaction Group. In addition, the Gas Contracting Group will be responsible for the procurement and contracting of long-term (greater than one-month) commodity supplies and capacity resources. Detailed organizational charts can be found at Appendices 1 and 2.

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3 The Gas Supply Planning and Load Forecasting Groups are based out of Waltham, MA. The Regulated Gas Transactions Group is based out of Hicksville, NY. The Gas Contracting Group is based out of Brooklyn, NY.

IV. RESOURCE PROCUREMENT

A. Determination of Gas Supply and Capacity Requirements

Gas supply and capacity (transportation or storage) requirements are established by the Gas Supply Planning and Load Forecasting Groups following the process specified in the IRP. A schematic listing of the upstream capacity resources currently available to meet the Company's firm sendout requirements is shown in Appendix 3. For supply and capacity requirements, the Gas Supply Planning Group will identify the desired quantity, duration, optimal receipt point(s), operational flexibility (i.e. baseload, first of the month swing, full swing, etc.) and nature of service (i.e. year round, seasonal, peaking, etc.). Once the requirements have been established, depending upon the duration of the requirement, the Gas Supply Planning Group will work with the Gas Contracting Group or the Regulated Gas Transactions Group to acquire the resource.

B. Procurement of Short Term Supply

For requirements of one month or less (spot purchases), gas supply will be acquired by the Regulated Gas Transactions Group during bid week or in the daily market as needed. Price is determined via verbal offers and short-term gas supply will only be acquired from creditworthy counter-parties with whom the company has a pre-established base contract (i.e. an industry standard NAESB agreement, a sample copy of which is provided in Appendix 4). All gas trades will be documented either via the Intercontinental Exchange ("ICE") electronic trading system, recorded telephone lines, or written confirmations.

C. Solicitation of Long Term Gas Supply Proposals

Long-term gas supply requirements (greater than one month) are secured by the Company's Gas Contracting Group in consultation with the Planning Group[4]. The Company may prepare a request for proposal (RFP) that will include a term sheet outlining the specific supply requirements (i.e. quantity, pipeline, receipt point(s), delivery point(s) desired price structure, operational flexibility, etc.). The RFP will also include other typical and customary procedural instructions. The RFP will be sent to qualified suppliers either via e-mail or in hard-copy. The Company will maintain a list of qualified suppliers. In order to be deemed qualified; a supplier must satisfy the Company's creditworthiness criteria, as established by KeySpan's Credit group, and must have entered into an industry standard agreement with the Company. The Company will continuously assess reliability based in part upon the supplier's short-term transaction performance.

D. Evaluation of Supply Offers and Negotiation of Agreements

Supply offers are evaluated jointly by the Company's Gas Contracting, Planning and Regulated Gas Transactions Groups to determine the best offer. The "best offer" is the offer that conforms most closely to the Company's requirements. Offers will be evaluated based upon both cost and non-cost factors including the supplier's experience, past performance, financial strength, ability to manage financial and physical risk and other factors that the Company

4 In certain instances, seasonal supplies may be procured by the regulated gas transaction group following the process for procurement of short-term supply.

deems relevant to the specific supply requirement. The Company will reserve the right to reject any or all offers and to negotiate with individual suppliers. Upon selection of the best offer, the Gas Contracting Group takes the lead in negotiating a formal written agreement. The industry standard NAESB contract is preferable for standard deals; however, certain transactions may require an individually negotiated agreement. Except for industry standard agreements that were previously subject to legal review, all agreements are reviewed with the Company's Legal Department to ensure that all provisions are consistent with applicable laws, regulations, industry standards and operational requirements. Upon completion of negotiations, the agreement will be executed by an authorized individual and entered and maintained in the applicable contract tracking systems.

E. Procurement of Incremental Capacity

When a need for incremental capacity is identified by the Gas Supply Planning Group, this Group works in concert with the Company's Gas Contracting Group to procure the incremental resource. In order to do so, the Company will evaluate all available options to determine the most economic resource with regard to meeting system operating and gas supply reliability requirements.[5] The Company maintains relationships with all regional pipeline companies and is active in gathering market intelligence from proposed pipeline projects with the potential to fulfill the Company's capacity needs. If no existing

5 In addition to considering new capacity, the Company will also consider the acquisition of existing capacity via assignment or capacity release.

projects meet the Company's requirements, the Company may initiate a project that meets its needs. Generally, when subscribing to new capacity, the Company will participate in pipeline open seasons. In coordination with the Gas Supply Planning Group, the Gas Contracting Group will take the lead in preparing and submitting open season requests and in negotiating precedent agreements and service agreements. Contract review and negotiation is done in coordination with the Company's Legal Department to ensure that all provisions are consistent with all applicable laws, regulations, industry standards and operational requirements. Upon completion of negotiations, the agreement will be executed by an authorized individual and entered and maintained in the applicable contract tracking systems.

F. Transaction Controls

The Gas Supply Planning Group will determine the Company's need for supply in order to meet customer requirements. The Company's Customer Choice Group will confirm the amount of gas received by EnergyNorth at the citygates on a daily basis.

Transactions executed by the Regulated Gas Transactions Group will be recorded on taped phone lines or documented electronically via the (ICE). If a transaction is executed using the ICE system, the gas trader will print out a confirmation sheet to document the transaction. Moreover, all gas supply purchase transactions will be recorded and entered into the Company's Nucleus

Transaction Management system ("Nucleus"). Nucleus will automatically assign a unique transaction number to each purchase and sale.

G. Natural Gas Price Risk Management Plan

A substantial portion of the Company's gas supply purchased in accordance with the above stated procedures is priced based on market indices. These "index priced" supplies are subject to market volatility. In order to mitigate gas cost increases and protect customers from the sharp swings in commodity prices that have become prevalent in the natural gas industry, the Company has in place a Natural Gas Price Risk Management Plan that attempts to stabilize the cost of gas to customers through the use of financial derivatives and active management of its underground storage supplies. A copy of the most recent Natural Gas Price Risk Management Plan approved by the Commission in Docket DG 05-127 is attached as Appendix 5.

V. OPERATIONAL PLANNING

Upon establishing a resource portfolio that is adequate to meet the projected requirements of its customers, it is the Company's responsibility to dispatch the assets based on actual weather as well as to perform portfolio management activities to further minimize the cost of maintaining the portfolio through mitigation measures.

Operational Planning encompasses the activity related to the actual dispatch of the assets in a least cost manner. These activities include daily, intraday, monthly, and seasonal planning and the dispatch of the assets (including LNG and LPG), as well as storage inventory and imbalance management. Currently, the Gas Supply Planning Group is responsible for these activities and it will continue to be responsible for them after April 1, 2006.

A. <u>Daily Forecasting</u>

The Gas Supply Planning Group, in conjunction with the Gas Control Group ("Gas Control"), utilizes a daily Game Plan, as referenced in Appendix 6, to coordinate the daily supply and demand balance. The Game Plan is an Excel spreadsheet that utilizes regression equations of base load plus heat load coefficients and forecasted degree day data for KeySpan's five New England divisions to calculate a short-term demand forecast. The forecast is verified on a regular basis and, as needed, adjusted in order to align with the most recent actual experienced data.

The demand side of the Game Plan is updated each morning by Gas Control. In addition, Gas Control populates the supply side of the Game Plan with information provided by the Gas Supply Planning and Customer Choice Groups the night before.[6] Every weekday morning, the groups meet to discuss the supply needs for the current day as well as the following gas day. In addition, prior to a weekend or holiday, the meeting will also address the planning for the following several days. At this meeting, the groups discuss any issues and strategy pertinent to putting together the daily sequence of supplies to be

[6] The Customer Choice group is responsible for confirming both, the supplies delivered to the Company from third party suppliers on behalf of transportation customers, as well as supplies delivered to the Company to meet customer requirements.

dispatched (the "daily setup"). This planning is done in time to execute prior to upstream pipeline nomination deadlines.

B. Nominations, Confirmations and Balancing

Beginning April 1, 2006, the Regulated Gas Transactions Group will be responsible for short term purchases, nominations and scheduling of the Company's pipeline and underground storage supplies, duties currently performed by Merrill Lynch. The gas schedulers will enter all transactions into nomination setup sheets, schedule the transactions on the various interstate pipelines' electronic bulletin boards (EBBs) and update the daily volume sheet (as shown in Appendix 7) with all gas supplies scheduled to be delivered to EnergyNorth's citygates. In addition, the schedulers will use the same template that third party marketers use to email system supply volumes to the Customer Choice Group (Appendix 8 - BMS Nomination Template). The Customer Choice Group will upload the nominations into its Broker Management System ("BMS") along with the nominations from the marketers. The Customer Choice Group will then confirm the total amount of gas received by EnergyNorth at its citygates on Tennessee using the Daily Scheduled Deliveries Detail Report (Appendix 9 - Daily Scheduled Deliveries Detail Report). The Planning Group will continue to dispatch and manage the Company's peaking contracts and peaking facilities (LNG and LPG).

At the end of each gas day, Gas Control is responsible for calculating sendout and tracking the Company's imbalances (Appendix 10 - EnergyNorth

Monthly Sendout Report). Each afternoon, Gas Control forwards the daily imbalance report to the Gas Supply Planning Group (Appendix 11 - Daily Imbalance Report). The Planning Group factors in the flexibility of its Operational Balancing Agreement ("OBA") when establishing the daily setup and manages its imbalance position. This activity will be handled by the Gas Supply Planning Group.[7]

The Company will maintain the information necessary to provide a monthly summary of all volumes purchased by EnergyNorth and the associated costs as shown in Appendix 12 - Monthly Merrill Lynch Report/Invoice.

C. Underground Storage

Currently, management of the Company's underground storage contracts is handled by Merrill Lynch. The Company pays Merrill Lynch to fill its storages on a $1/7^{th}$ basis during the months of April through October. Effective April 1, 2006, the Company will manage these contracts through the Regulated Gas Transactions Group. As discussed in the Company's Natural Gas Price Risk Management Plan (Appendix 5), the Company will employ a similar $1/7^{th}$ refill strategy. However, unlike the arrangement with Merrill Lynch, operational flexibilities will need to be considered when developing its injection plan. For

[7] Currently, EnergyNorth enjoys the benefits of operating under a single OBA with Tennessee for all of the KeySpan New England citygates. This allows EnergyNorth and the KeySpan Massachusetts LDCs to balance deliveries across all of its Tennessee citygates in New England. The Company hopes to maintain a single Tennessee OBA, however it is contingent upon the Company's portfolio management plan decision for the Massachusetts LDCs effective April 1, 2006.

example, the Company may not fill some of its larger storage fields to 100% full at the beginning of November in order to accommodate for warmer than planned weather and the need to inject gas into storage at the beginning of the month. The Company will maintain the information necessary to provide a monthly storage report similar to the one currently supplied by Merrill Lynch (Appendix 13 - Monthly Storage Report).

D. <u>Capacity Release and Off-System Sale Optimization Opportunities</u>

Since the Company must maintain sufficient capacity in its resource portfolio to meet current and expected design day and design year customer requirements, at any given time, it may have resources that are temporarily under-utilized. On a daily, monthly and seasonal basis, the Planning Group will identify those resources that are not needed to meet firm sendout requirements. Any surplus resources that are identified will be made available for optimization via capacity release and/or off-system sale. It will be the responsibility of the Regulated Gas Transactions Group to market these resources in an effort to maximize their value. Revenues realized from capacity release or off-system sales transactions will be credited to EnergyNorth customers as an offset to gas costs. The Company will maintain the information necessary to provide reports detailing these types of transactions.

E. Peak Season Planning

At the start of each winter season, the Gas Supply Planning Group hosts a Winter Operations Meeting attended by various departments throughout the Company including Gas Control, Gas Production, Engineering, Load Forecasting, Legal, Customer Choice, Transactions and Rates to review plans for the upcoming winter (Appendix 14 - Winter Operations 2005/06 Presentation). In preparation for this meeting, the Gas Supply Planning Group prepares a Gas Supply Winter Operations Manual for each participant that provides pertinent information regarding the gas supply portfolio, production statistics, etc. Lastly, the Gas Supply Planning Group holds a Weekly Winter Operations Meeting (during the entire winter period) with representatives from Gas Control, Regulated Gas Transactions, Gas Production, Engineering, Load Forecasting and Customer Choice. These meetings are held to discuss actual and forecasted weather and sendout data, storage inventories, LNG and LPG refill coordination, and any other relevant issues.

VI. SUPPLY VALIDATION AND INVOICE RECONCILIATION

Supply validation and invoice reconciliation is and will continue to be performed by two groups, the Transaction Back office and Corporate Accounting. Both groups reside within the Company's finance organization.

A. <u>Physical Natural Gas/LNG Transaction Reporting and Invoicing</u>

This process includes the preparation of monthly accrual of gas transactions made by and entered into the Company's NUCLEUS Risk Management system; this accrual is recorded by to Corporate Accounting at month end to the Company's general ledger.

As part of this accrual process, the Transaction Back Office provides a validation of data entered into NUCLEUS. Volumes are reconciled by the Transaction Back Office through SCADA system reports provided by Gas Control. Additionally, the following sources are utilized by the Transaction Back Office to validate gas costs: This process ensures that the Company's purchases align with sendout.

- The Nucleus Invoice Module is used to prepare the accrual and to validate invoices after the Mid Office, a term used to define the segregation of duties within the Regulated Gas Transactions Group, inputs daily gas purchases and prices in to the Nucleus, as well as storage injections and withdrawals.
- Customer Choice's Capacity Release Financial Summary report which documents pipeline capacity releases and Marketer managed supply, as well as transport gas from the Marketers is used during the accrual process and to support invoice review (see Appendix 15 – Capacity Release Financial Summary).

- Gas Control produces send-out reports by division, LNG trucking and vapor reports, supplemental usage reports for Boil-off and an Operational Balance Agreement (OBA) report which captures the pipeline imbalance for Tennessee (See Appendix 11).

B. Invoice Review

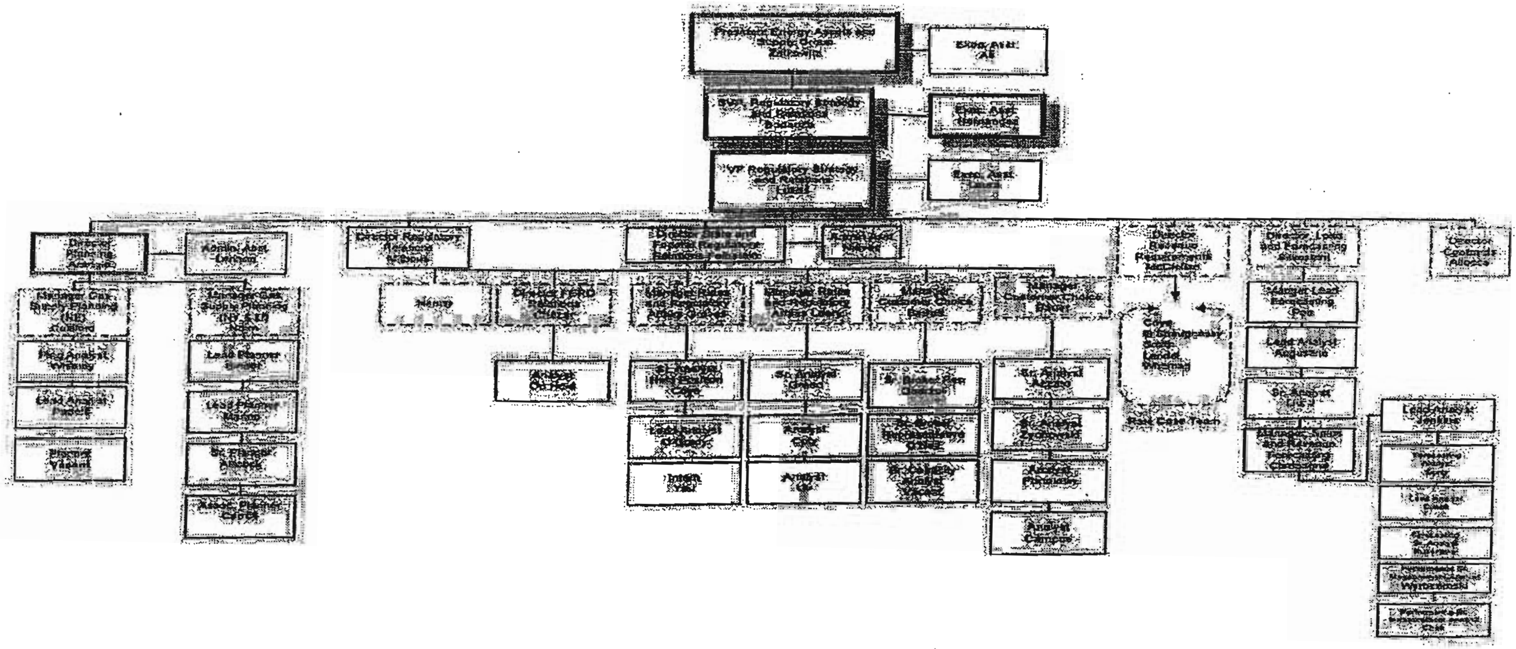
The Transaction Back Office is also responsible for invoice validation. This process consists of verifying invoices for volume, price and tariff information against that which is recorded in the Company's NUCLEUS Risk Management system. Actual invoice payments are verified against the initial accrual. Invoices are approved and signed and forwarded to Corporate Accounting and Treasury for payment. The Transaction Back Office is also responsible for working with Corporate Accounting to ensure that all invoices are accurately recorded.

C. Financial (Hedging) Transaction Settlements

The Transaction Back Office is also responsible for confirming all financial settlement payment figures and preparing/submitting invoices on hedge gain settlements to counterparties, reviewing and approving of all counter-party hedge loss settlement invoices, and processing invoices related to margin activity. The Transaction Back Office Manager or Director approves all settlement invoicing. The Transaction Back Office is also responsible for working with Corporate Accounting to ensure that all invoices are accurately recorded.

Appendix 1

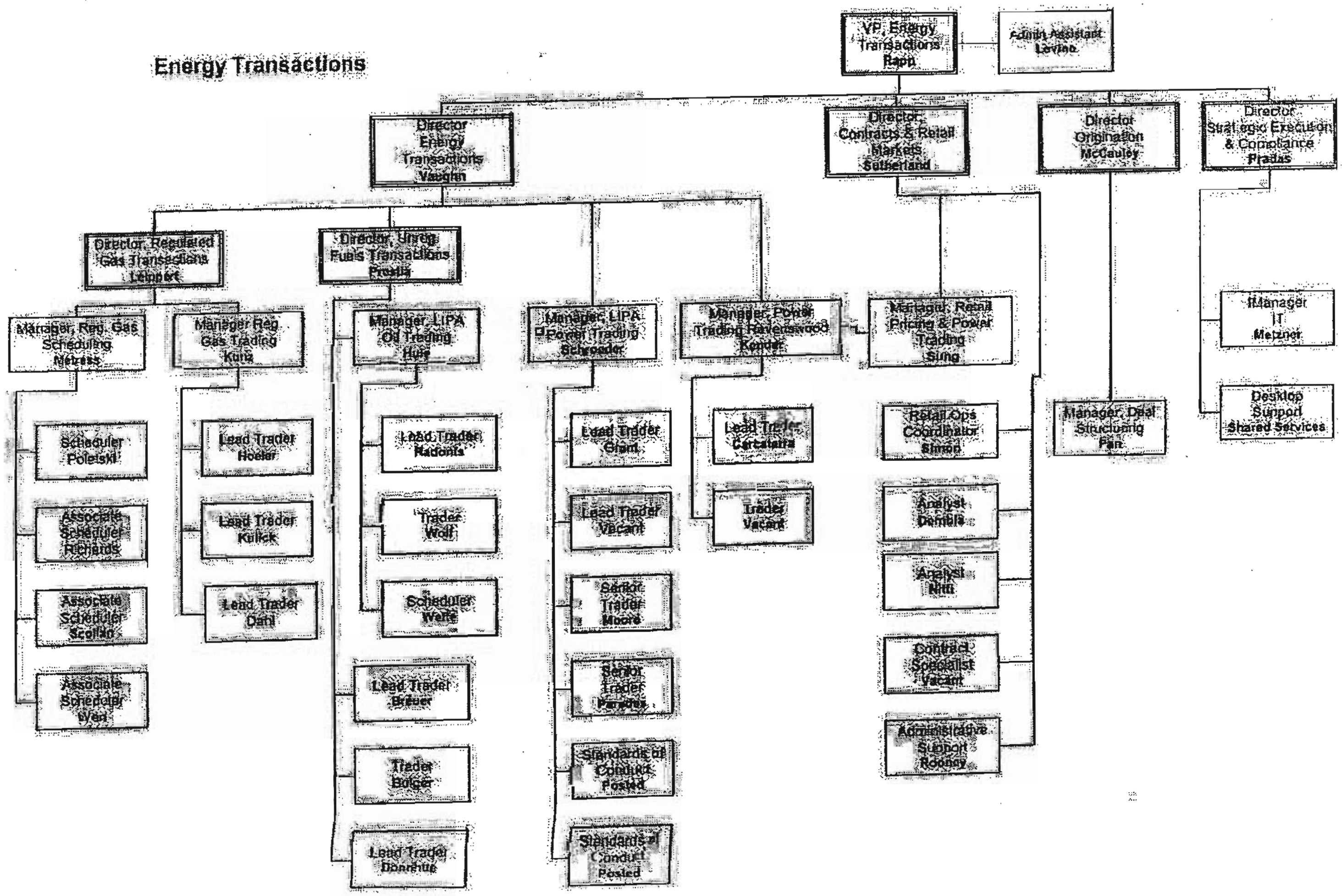
KeySpan Asset Optimization Group Organizational Chart



Appendix 2

KeySpan Regulated Gas Transaction Group Organizational Chart

Energy Transactions

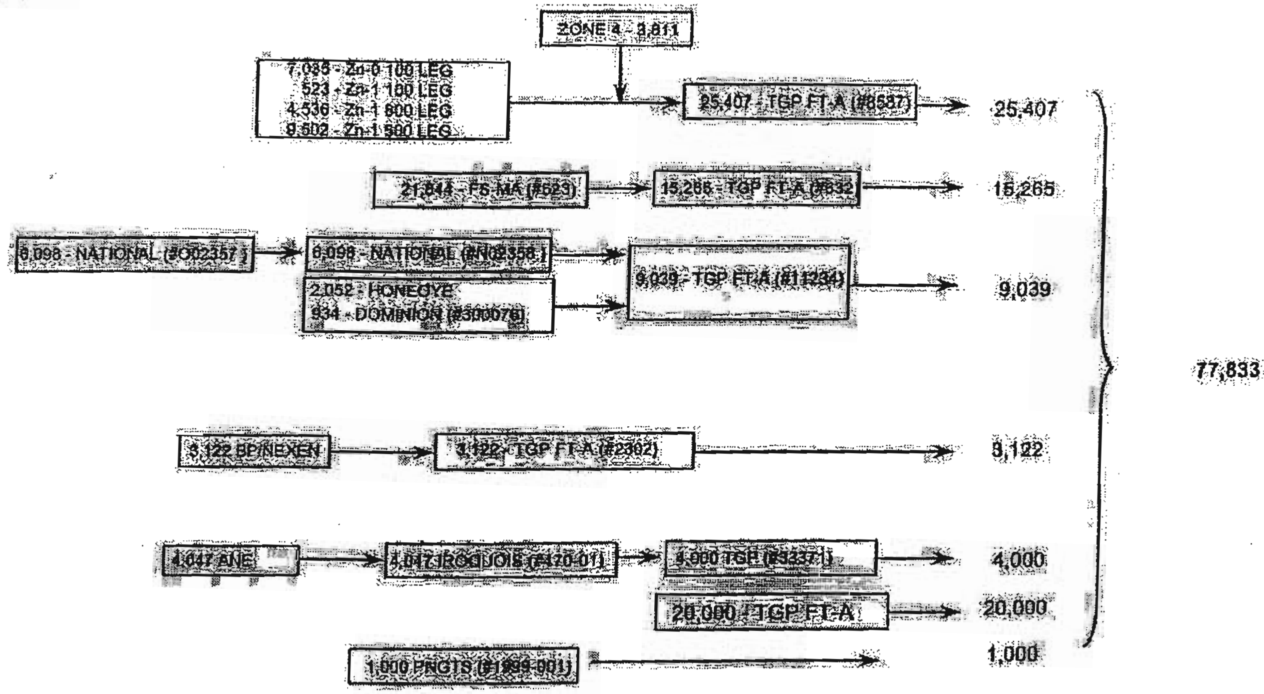


Appendix 3

Schematic of KeySpan Upstream Capacity Resources

As of November 1, 2005

ENERGYNORTH GAS COMPANY
DESIGN DAY
PIPELINE TRANSPORTATION AND STORAGE
(MMBtu)



Note:
(1) EnergyNorth has a Peaking Service with ABS Londonderry. Up to 15,000/day for 30 days.
(2) CoEnergy Trading Co. will baseload 20,000 FTA capacity Dec-Feb.

Appendix 4

KeySpan New England Sample NAESB Agreement

Base Contract for Sale and Purchase of Natural Gas

This Base Contract is entered into as of the following date: June xx, 2005. The parties to this Base Contract are the following:

____________________	and	Energy North Gas Co. DBA Keyspan Energy Delivery, N.E.
____________________		52 Second Avenue, Waltham, MA 02451
Duns Number:		Duns Number: 194387015
Contract Number:		Contract Number:
U.S. Federal Tax ID Number:		U.S. Federal Tax ID Number: 02-0209312
Notices:		
		Energy North Gas Co. DBA Keyspan Energy Delivery, N.E.
Attn:		Attn: Energy Supply Department
Phone: Fax:		Phone: (781) 466-5066 Fax: (781) 290-0186
Confirmations:		
		Energy North Gas Co. DBA Keyspan Energy Delivery, N.E.
Attn:		Attn: Energy Supply Department
Phone: Fax:		Phone: (781) 466-5066 Fax: (781) 290-0186
Invoices and Payments:		
		Energy North Gas Co. DBA Keyspan Energy Delivery, N.E.
Attn:		Attn: Energy Supply Department
		52 Second Avenue, Waltham, MA 02451
Phone: Fax:		Phone: (781) 466-5066 Fax: (781) 290-0186
Wire Transfer or ACH Numbers (if applicable):		
BANK:		BANK:
ABA:		ABA:
ACCT:		ACCT:
Other Details:		Other Details:

This Base Contract incorporates by reference for all purposes the General Terms and Conditions for Sale and Purchase of Natural Gas published by the North American Energy Standards Board. The parties hereby agree to the following provisions offered in said General Terms and Conditions. In the event the parties fail to check a box, the specified default provision shall apply. Select only one box from each section:

Section 1.2 Transaction Procedure	■ Oral (default) □ Written	**Section 7.2** Payment Date	■ 25th Day of Month following Month of delivery (default) □ ____ Day of Month following Month of delivery
Section 2.5 Confirm Deadline	■ 2 Business Days after receipt (default) □ _____ Business Days after receipt	**Section 7.2** Method of Payment	■ Wire transfer (default) ■ Automated Clearinghouse Credit (ACH) □ Check
Section 2.6 Confirming Party	■ Seller (default) □ Buyer □	**Section 7.7** Netting	■ Netting applies (default) □ Netting does not apply
Section 3.2 Performance Obligation	■ Cover Standard (default) □ Spot Price Standard	**Section 10.3.1** Early Termination Damages	■ Early Termination Damages Apply (default) □ Early Termination Damages Do Not Apply
Note: The following Spot Price Publication applies to both of the immediately preceding.		**Section 10.3.2** Other Agreement Setoffs	■ Other Agreement Setoffs Apply (default) □ Other Agreement Setoffs Do Not Apply
Section 2.26 Spot Price Publication	■ Gas Daily Midpoint (default) □ ____________	**Section 14.5** Choice Of Law	New York
Section 6 Taxes	■ Buyer Pays At and After Delivery Point (default) □ Seller Pays Before and At Delivery Point	**Section 14.10** Confidentiality	■ Confidentiality applies (default) □ Confidentiality does not apply
□ Special Provisions Number of sheets attached: □ Addendum(s):			

IN WITNESS WHEREOF, the parties hereto have executed this Base Contract in duplicate.

____________________	Energy North Gas Co. DBA Keyspan Energy Delivery, N.E.
Party Name	Party Name
By ____________________	By ____________________
Name:	Name:
Title:	Title:

General Terms and Conditions
Base Contract for Sale and Purchase of Natural Gas

SECTION 1. PURPOSE AND PROCEDURES

1.1. These General Terms and Conditions are intended to facilitate purchase and sale transactions of Gas on a Firm or Interruptible basis. "Buyer" refers to the party receiving Gas and "Seller" refers to the party delivering Gas. The entire agreement between the parties shall be the Contract as defined in Section 2.7.

The parties have selected either the "Oral Transaction Procedure" or the "Written Transaction Procedure" as indicated on the Base Contract.
Oral Transaction Procedure:
1.2. The parties will use the following Transaction Confirmation procedure. Any Gas purchase and sale transaction may be effectuated in an EDI transmission or telephone conversation with the offer and acceptance constituting the agreement of the parties. The parties shall be legally bound from the time they so agree to transaction terms and may each rely thereon. Any such transaction shall be considered a "writing" and to have been "signed". Notwithstanding the foregoing sentence, the parties agree that Confirming Party shall, and the other party may, confirm a telephonic transaction by sending the other party a Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means within three Business Days of a transaction covered by this Section 1.2 (Oral Transaction Procedure) provided that the failure to send a Transaction Confirmation shall not invalidate the oral agreement of the parties. Confirming Party adopts its confirming letterhead, or the like, as its signature on any Transaction Confirmation as the identification and authentication of Confirming Party. If the Transaction Confirmation contains any provisions other than those relating to the commercial terms of the transaction (i.e., price, quantity, performance obligation, delivery point, period of delivery and/or transportation conditions), which modify or supplement the Base Contract or General Terms and Conditions of this Contract (e.g., arbitration or additional representations and warranties), such provisions shall not be deemed to be accepted pursuant to Section 1.3 but must be expressly agreed to by both parties; provided that the foregoing shall not invalidate any transaction agreed to by the parties.
Written Transaction Procedure:
1.2. The parties will use the following Transaction Confirmation procedure. Should the parties come to an agreement regarding a Gas purchase and sale transaction for a particular Delivery Period, the Confirming Party shall, and the other party may, record that agreement on a Transaction Confirmation and communicate such Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means, to the other party by the close of the Business Day following the date of agreement. The parties acknowledge that their agreement will not be binding until the exchange of nonconflicting Transaction Confirmations or the passage of the Confirm Deadline without objection from the receiving party, as provided in Section 1.3.

1.3. If a sending party's Transaction Confirmation is materially different from the receiving party's understanding of the agreement referred to in Section 1.2, such receiving party shall notify the sending party via facsimile, EDI or mutually agreeable electronic means by the Confirm Deadline, unless such receiving party has previously sent a Transaction Confirmation to the sending party. The failure of the receiving party to so notify the sending party in writing by the Confirm Deadline constitutes the receiving party's agreement to the terms of the transaction described in the sending party's Transaction Confirmation. If there are any material differences between timely sent Transaction Confirmations governing the same transaction, then neither Transaction Confirmation shall be binding until or unless such differences are resolved including the use of any evidence that clearly resolves the differences in the Transaction Confirmations. In the event of a conflict among the terms of (i) a binding Transaction Confirmation pursuant to Section 1.2, (ii) the oral agreement of the parties which may be evidenced by a recorded conversation, where the parties have selected the Oral Transaction Procedure of the Base Contract, (iii) the Base Contract, and (iv) these General Terms and Conditions, the terms of the documents shall govern in the priority listed in this sentence.

1.4. The parties agree that each party may electronically record all telephone conversations with respect to this Contract between their respective employees, without any special or further notice to the other party. Each party shall obtain any necessary consent of its agents and employees to such recording. Where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, the parties agree not to contest the validity or enforceability of telephonic recordings entered into in accordance with the requirements of this Base Contract. However, nothing herein shall be construed as a waiver of any objection to the admissibility of such evidence.

SECTION 2. DEFINITIONS

The terms set forth below shall have the meaning ascribed to them below. Other terms are also defined elsewhere in the Contract and shall have the meanings ascribed to them herein.

2.1. "Alternative Damages" shall mean such damages, expressed in dollars or dollars per MMBtu, as the parties shall agree upon in the Transaction Confirmation, in the event either Seller or Buyer fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer.

2.2. "Base Contract" shall mean a contract executed by the parties that incorporates these General Terms and Conditions by reference; that specifies the agreed selections of provisions contained herein; and that sets forth other information required herein and any Special Provisions and addendum(s) as identified on page one.

2.3. "British thermal unit" or "Btu" shall mean the International BTU, which is also called the Btu (IT).

2.4. "Business Day" shall mean any day except Saturday, Sunday or Federal Reserve Bank holidays.

2.5. "Confirm Deadline" shall mean 5:00 p.m. in the receiving party's time zone on the second Business Day following the Day a Transaction Confirmation is received or, if applicable, on the Business Day agreed to by the parties in the Base Contract; provided, if the Transaction Confirmation is time stamped after 5:00 p.m. in the receiving party's time zone, it shall be deemed received at the opening of the next Business Day.

2.6. "Confirming Party" shall mean the party designated in the Base Contract to prepare and forward Transaction Confirmations to the other party.

2.7. "Contract" shall mean the legally-binding relationship established by (i) the Base Contract, (ii) any and all binding Transaction Confirmations and (iii) where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, any and all transactions that the parties have entered into through an EDI transmission or by telephone, but that have not been confirmed in a binding Transaction Confirmation.

2.8. "Contract Price" shall mean the amount expressed in U.S. Dollars per MMBtu to be paid by Buyer to Seller for the purchase of Gas as agreed to by the parties in a transaction.

2.9. "Contract Quantity" shall mean the quantity of Gas to be delivered and taken as agreed to by the parties in a transaction.

2.10. "Cover Standard", as referred to in Section 3.2, shall mean that if there is an unexcused failure to take or deliver any quantity of Gas pursuant to this Contract, then the performing party shall use commercially reasonable efforts to (i) if Buyer is the performing party, obtain Gas, (or an alternate fuel if elected by Buyer and replacement Gas is not available), or (ii) if Seller is the performing party, sell Gas, in either case, at a price reasonable for the delivery or production area, as applicable, consistent with: the amount of notice provided by the nonperforming party; the immediacy of the Buyer's Gas consumption needs or Seller's Gas sales requirements, as applicable; the quantities involved; and the anticipated length of failure by the nonperforming party.

2.11. "Credit Support Obligation(s)" shall mean any obligation(s) to provide or establish credit support for, or on behalf of, a party to this Contract such as an irrevocable standby letter of credit, a margin agreement, a prepayment, a security interest in an asset, a performance bond, guaranty, or other good and sufficient security of a continuing nature.

2.12. "Day" shall mean a period of 24 consecutive hours, coextensive with a "day" as defined by the Receiving Transporter in a particular transaction.

2.13. "Delivery Period" shall be the period during which deliveries are to be made as agreed to by the parties in a transaction.

2.14. "Delivery Point(s)" shall mean such point(s) as are agreed to by the parties in a transaction.

2.15. "EDI" shall mean an electronic data interchange pursuant to an agreement entered into by the parties, specifically relating to the communication of Transaction Confirmations under this Contract.

2.16. "EFP" shall mean the purchase, sale or exchange of natural Gas as the "physical" side of an exchange for physical transaction involving gas futures contracts. EFP shall incorporate the meaning and remedies of "Firm", provided that a party's excuse for nonperformance of its obligations to deliver or receive Gas will be governed by the rules of the relevant futures exchange regulated under the Commodity Exchange Act.

2.17. "Firm" shall mean that either party may interrupt its performance without liability only to the extent that such performance is prevented for reasons of Force Majeure; provided, however, that during Force Majeure interruptions, the party invoking Force Majeure may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by the Transporter.

2.18. "Gas" shall mean any mixture of hydrocarbons and noncombustible gases in a gaseous state consisting primarily of methane.

2.19. "Imbalance Charges" shall mean any fees, penalties, costs or charges (in cash or in kind) assessed by a Transporter for failure to satisfy the Transporter's balance and/or nomination requirements.

2.20. "Interruptible" shall mean that either party may interrupt its performance at any time for any reason, whether or not caused by an event of Force Majeure, with no liability, except such interrupting party may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by Transporter.

2.21. "MMBtu" shall mean one million British thermal units, which is equivalent to one dekatherm.

2.22. "Month" shall mean the period beginning on the first Day of the calendar month and ending immediately prior to the commencement of the first Day of the next calendar month.

2.23. "Payment Date" shall mean a date, as indicated on the Base Contract, on or before which payment is due Seller for Gas received by Buyer in the previous Month.

2.24. "Receiving Transporter" shall mean the Transporter receiving Gas at a Delivery Point, or absent such receiving Transporter, the Transporter delivering Gas at a Delivery Point.

2.25. "Scheduled Gas" shall mean the quantity of Gas confirmed by Transporter(s) for movement, transportation or management.

2.26. "Spot Price " as referred to in Section 3.2 shall mean the price listed in the publication indicated on the Base Contract, under the listing applicable to the geographic location closest in proximity to the Delivery Point(s) for the relevant Day; provided, if there is no single price published for such location for such Day, but there is published a range of prices, then the Spot Price shall be the average of such high and low prices. If no price or range of prices is published for such Day, then the Spot Price shall be the average of the following: (i) the price (determined as stated above) for the first Day for which a price or range of prices is published that next precedes the relevant Day; and (ii) the price (determined as stated above) for the first Day for which a price or range of prices is published that next follows the relevant Day.

2.27. "Transaction Confirmation" shall mean a document, similar to the form of Exhibit A, setting forth the terms of a transaction formed pursuant to Section 1 for a particular Delivery Period.

2.28. "Termination Option" shall mean the option of either party to terminate a transaction in the event that the other party fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer for a designated number of days during a period as specified on the applicable Transaction Confirmation.

2.29. "Transporter(s)" shall mean all Gas gathering or pipeline companies, or local distribution companies, acting in the capacity of a transporter, transporting Gas for Seller or Buyer upstream or downstream, respectively, of the Delivery Point pursuant to a particular transaction.

SECTION 3. PERFORMANCE OBLIGATION

3.1. Seller agrees to sell and deliver, and Buyer agrees to receive and purchase, the Contract Quantity for a particular transaction in accordance with the terms of the Contract. Sales and purchases will be on a Firm or Interruptible basis, as agreed to by the parties in a transaction.

The parties have selected either the "Cover Standard" or the "Spot Price Standard" as indicated on the Base Contract.

Cover Standard:

3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard and the Contract Price, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller for such Day(s); or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in the amount equal to the positive difference, if any, between the Contract Price and the price received by Seller utilizing the Cover Standard for the resale of such Gas, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually taken by Buyer for such Day(s); or (iii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available, then the sole and exclusive remedy of the performing party shall be any unfavorable difference between the Contract Price and the Spot Price, adjusted for such transportation to the applicable Delivery Point, multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller and received by Buyer for such Day(s). Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

Spot Price Standard:

3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the Contract Price from the Spot Price; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the applicable Spot Price from the Contract Price. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

3.3. Notwithstanding Section 3.2, the parties may agree to Alternative Damages in a Transaction Confirmation executed in writing by both parties.

3.4. In addition to Sections 3.2 and 3.3, the parties may provide for a Termination Option in a Transaction Confirmation executed in writing by both parties. The Transaction Confirmation containing the Termination Option will designate the length of nonperformance triggering the Termination Option and the procedures for exercise thereof, how damages for nonperformance will be compensated, and how liquidation costs will be calculated.

SECTION 4. TRANSPORTATION, NOMINATIONS, AND IMBALANCES

4.1. Seller shall have the sole responsibility for transporting the Gas to the Delivery Point(s). Buyer shall have the sole responsibility for transporting the Gas from the Delivery Point(s).

4.2. The parties shall coordinate their nomination activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior Notice, sufficient to meet the requirements of all Transporter(s) involved in the transaction, of the quantities of Gas to be delivered and purchased each Day. Should either party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.

4.3. The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's receipt of quantities of Gas greater than or less than the Scheduled Gas, then Buyer shall pay for such Imbalance Charges or reimburse Seller for such Imbalance Charges paid by Seller. If the Imbalance Charges were incurred as a result of Seller's delivery of quantities of Gas greater than or less than the Scheduled Gas, then Seller shall pay for such Imbalance Charges or reimburse Buyer for such Imbalance Charges paid by Buyer.

SECTION 5. QUALITY AND MEASUREMENT

All Gas delivered by Seller shall meet the pressure, quality and heat content requirements of the Receiving Transporter. The unit of quantity measurement for purposes of this Contract shall be one MMBtu dry. Measurement of Gas quantities hereunder shall be in accordance with the established procedures of the Receiving Transporter.

SECTION 6. TAXES

The parties have selected either "Buyer Pays At and After Delivery Point" or "Seller Pays Before and At Delivery Point" as indicated on the Base Contract.
Buyer Pays At and After Delivery Point:
Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas at the Delivery Point(s) and all Taxes after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.
Seller Pays Before and At Delivery Point:
Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s) and all Taxes at the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

SECTION 7. BILLING, PAYMENT, AND AUDIT

7.1. Seller shall invoice Buyer for Gas delivered and received in the preceding Month and for any other applicable charges, providing supporting documentation acceptable in industry practice to support the amount charged. If the actual quantity delivered is not known by the billing date, billing will be prepared based on the quantity of Scheduled Gas. The invoiced quantity will then be adjusted to the actual quantity on the following Month's billing or as soon thereafter as actual delivery information is available.

7.2. Buyer shall remit the amount due under Section 7.1 in the manner specified in the Base Contract, in immediately available funds, on or before the later of the Payment Date or 10 Days after receipt of the invoice by Buyer; provided that if the Payment Date is not a Business Day, payment is due on the next Business Day following that date. In the event any payments are due Buyer hereunder, payment to Buyer shall be made in accordance with this Section 7.2.

7.3. In the event payments become due pursuant to Sections 3.2 or 3.3, the performing party may submit an invoice to the nonperforming party for an accelerated payment setting forth the basis upon which the invoiced amount was calculated. Payment from the nonperforming party will be due five Business Days after receipt of invoice.

7.4. If the invoiced party, in good faith, disputes the amount of any such invoice or any part thereof, such invoiced party will pay such amount as it concedes to be correct; provided, however, if the invoiced party disputes the amount due, it must provide supporting documentation acceptable in industry practice to support the amount paid or disputed. In the event the parties are unable to resolve such dispute, either party may pursue any remedy available at law or in equity to enforce its rights pursuant to this Section.

7.5. If the invoiced party fails to remit the full amount payable when due, interest on the unpaid portion shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

7.6. A party shall have the right, at its own expense, upon reasonable Notice and at reasonable times, to examine and audit and to obtain copies of the relevant portion of the books, records, and telephone recordings of the other party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment, or computation made under the Contract. This right to examine, audit, and to obtain copies shall not be available with respect to proprietary information not directly relevant to transactions under this Contract. All invoices and billings shall be conclusively presumed final and accurate and all associated claims for under- or overpayments shall be deemed waived unless such invoices or billings are objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery. All retroactive adjustments under Section 7 shall be paid in full by the party owing payment within 30 Days of Notice and substantiation of such inaccuracy.

7.7. Unless the parties have elected on the Base Contract not to make this Section 7.7 applicable to this Contract, the parties shall net all undisputed amounts due and owing, and/or past due, arising under the Contract such that the party owing the greater amount shall make a single payment of the net amount to the other party in accordance with Section 7; provided that no payment required to be made pursuant to the terms of any Credit Support Obligation or pursuant to Section 7.3 shall be subject to netting under this Section. If the parties have executed a separate netting agreement, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 8. TITLE, WARRANTY, AND INDEMNITY

8.1. Unless otherwise specifically agreed, title to the Gas shall pass from Seller to Buyer at the Delivery Point(s). Seller shall have responsibility for and assume any liability with respect to the Gas prior to its delivery to Buyer at the specified Delivery Point(s). Buyer shall have responsibility for and any liability with respect to said Gas after its delivery to Buyer at the Delivery Point(s).

8.2. Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances, and claims. EXCEPT AS PROVIDED IN THIS SECTION 8.2 AND IN SECTION 14.8, ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR OF FITNESS FOR ANY PARTICULAR PURPOSE, ARE DISCLAIMED.

8.3. Seller agrees to indemnify Buyer and save it harmless from all losses, liabilities or claims including reasonable attorneys' fees and costs of court ("Claims"), from any and all persons, arising from or out of claims of title, personal injury or property damage from said Gas or other charges thereon which attach before title passes to Buyer. Buyer agrees to indemnify Seller and save it harmless from all Claims, from any and all persons, arising from or out of claims regarding payment, personal injury or property damage from said Gas or other charges thereon which attach after title passes to Buyer.

8.4. Notwithstanding the other provisions of this Section 8, as between Seller and Buyer, Seller will be liable for all Claims to the extent that such arise from the failure of Gas delivered by Seller to meet the quality requirements of Section 5.

SECTION 9. NOTICES

9.1. All Transaction Confirmations, invoices, payments and other communications made pursuant to the Base Contract ("Notices") shall be made to the addresses specified in writing by the respective parties from time to time.

9.2. All Notices required hereunder may be sent by facsimile or mutually acceptable electronic means, a nationally recognized overnight courier service, first class mail or hand delivered.

9.3. Notice shall be given when received on a Business Day by the addressee. In the absence of proof of the actual receipt date, the following presumptions will apply. Notices sent by facsimile shall be deemed to have been received upon the sending party's receipt of its facsimile machine's confirmation of successful transmission. If the day on which such facsimile is received is not a Business Day or is after five p.m. on a Business Day, then such facsimile shall be deemed to have been received on the next following Business Day. Notice by overnight mail or courier shall be deemed to have been received on the next Business Day after it was sent or such earlier time as is confirmed by the receiving party. Notice via first class mail shall be considered delivered five Business Days after mailing.

SECTION 10. FINANCIAL RESPONSIBILITY

10.1. If either party ("X") has reasonable grounds for insecurity regarding the performance of any obligation under this Contract (whether or not then due) by the other party ("Y") (including, without limitation, the occurrence of a material change in the creditworthiness of Y), X may demand Adequate Assurance of Performance. "Adequate Assurance of Performance" shall mean sufficient security in the form, amount and for the term reasonably acceptable to X, including, but not limited to, a standby irrevocable letter of credit, a prepayment, a security interest in an asset or a performance bond or guaranty (including the issuer of any such security).

10.2. In the event (each an "Event of Default") either party (the "Defaulting Party") or its guarantor shall: (i) make an assignment or any general arrangement for the benefit of creditors; (ii) file a petition or otherwise commence, authorize, or acquiesce in the commencement of a proceeding or case under any bankruptcy or similar law for the protection of creditors or have such petition filed or proceeding commenced against it; (iii) otherwise become bankrupt or insolvent (however evidenced); (iv) be unable to pay its debts as they fall due; (v) have a receiver, provisional liquidator, conservator, custodian, trustee or other similar official appointed with respect to it or substantially all of its assets; (vi) fail to perform any obligation to the other party with respect to any Credit Support Obligations relating to the Contract; (vii) fail to give Adequate Assurance of Performance under Section 10.1 within 48 hours but at least one Business Day of a written request by the other party; or (viii) not have paid any amount due the other party hereunder on or before the second Business Day following written Notice that such payment is due; then the other party (the "Non-Defaulting Party") shall have the right, at its sole election, to immediately withhold and/or suspend deliveries or payments upon Notice and/or to terminate and liquidate the transactions under the Contract, in the manner provided in Section 10.3, in addition to any and all other remedies available hereunder.

10.3. If an Event of Default has occurred and is continuing, the Non-Defaulting Party shall have the right, by Notice to the Defaulting Party, to designate a Day, no earlier than the Day such Notice is given and no later than 20 Days after such Notice is given, as an early termination date (the "Early Termination Date") for the liquidation and termination pursuant to Section 10.3.1 of all transactions under the Contract, each a "Terminated Transaction". On the Early Termination Date, all transactions will terminate, other than those transactions, if any, that may not be liquidated and terminated under applicable law or that are, in the reasonable opinion of the Non-Defaulting Party, commercially impracticable to liquidate and terminate ("Excluded Transactions"), which Excluded Transactions must be liquidated and terminated as soon thereafter as is reasonably practicable, and upon termination shall be a Terminated Transaction and be valued consistent with Section 10.3.1 below. With respect to each Excluded Transaction, its actual termination date shall be the Early Termination Date for purposes of Section 10.3.1.

The parties have selected either "Early Termination Damages Apply" or "Early Termination Damages Do Not Apply" as indicated on the Base Contract.
Early Termination Damages Apply:
10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, (i) the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract and (ii) the Market Value, as defined below, of each Terminated Transaction. The Non-Defaulting Party shall (x) liquidate and accelerate each Terminated Transaction at its Market Value, so that each amount equal to the difference between such Market Value and the Contract Value, as defined below, of such Terminated Transaction(s) shall be due to the Buyer under the Terminated Transaction(s) if such Market Value exceeds the Contract Value and to the Seller if the opposite is the case; and (y) where appropriate, discount each amount then due under clause (x) above to present value in a commercially reasonable manner as of the Early Termination Date (to take account of the period between the date of liquidation and the date on which such amount would have otherwise been due pursuant to the relevant Terminated Transactions). For purposes of this Section 10.3.1, "Contract Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the Contract Price, and "Market Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the market price for a similar transaction at the Delivery Point determined by the Non-Defaulting Party in a commercially reasonable manner. To ascertain the Market Value, the Non-Defaulting Party may consider, among other valuations, any or all of the settlement prices of NYMEX Gas futures contracts, quotations from leading dealers in energy swap contracts or physical gas trading markets, similar sales or purchases and any other bona fide third-party offers, all adjusted for the length of the term and differences in transportation costs. A party shall not be required to enter into a replacement transaction(s) in order to determine the Market Value. Any extension(s) of the term of a transaction to which parties are not bound as of the Early Termination Date (including but not limited to "evergreen provisions") shall not be considered in determining Contract Values and Market Values. For the avoidance of doubt, any option pursuant to which one party has the right to extend the term of a transaction shall be considered in determining Contract Values and Market Values. The rate of interest used in calculating net present value shall be determined by the Non-Defaulting Party in a commercially reasonable manner.
Early Termination Damages Do Not Apply:
10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract.
The parties have selected either "Other Agreement Setoffs Apply" or "Other Agreement Setoffs Do Not Apply" as indicated on the Base Contract.
Other Agreement Setoffs Apply:
10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party may setoff (i) any Net Settlement Amount owed to the Non-Defaulting Party against any margin or other collateral held by it in connection with any Credit Support Obligation relating to the Contract; or (ii) any Net Settlement Amount payable to the Defaulting Party against any amount(s) payable by the Defaulting Party to the Non-Defaulting Party under any other agreement or arrangement between the parties.
Other Agreement Setoffs Do Not Apply:
10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party may setoff any Net Settlement Amount owed to the Non-Defaulting Party against any margin or other collateral held by it in connection with any Credit Support Obligation relating to the Contract.

10.3.3. If any obligation that is to be included in any netting, aggregation or setoff pursuant to Section 10.3.2 is unascertained, the Non-Defaulting Party may in good faith estimate that obligation and net, aggregate or setoff, as applicable, in respect of the estimate, subject to the Non-Defaulting Party accounting to the Defaulting Party when the obligation is ascertained. Any amount not then due which is included in any netting, aggregation or setoff pursuant to Section 10.3.2 shall be discounted to net present value in a commercially reasonable manner determined by the Non-Defaulting Party.

10.4. As soon as practicable after a liquidation, Notice shall be given by the Non-Defaulting Party to the Defaulting Party of the Net Settlement Amount, and whether the Net Settlement Amount is due to or due from the Non-Defaulting Party. The Notice shall include a written statement explaining in reasonable detail the calculation of such amount, provided that failure to give such Notice shall not affect the validity or enforceability of the liquidation or give rise to any claim by the Defaulting Party against the Non-Defaulting Party. The Net Settlement Amount shall be paid by the close of business on the second Business Day following such Notice, which date shall not be earlier than the Early Termination Date. Interest on any unpaid portion of the Net Settlement Amount shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

10.5. The parties agree that the transactions hereunder constitute a "forward contract" within the meaning of the United States Bankruptcy Code and that Buyer and Seller are each "forward contract merchants" within the meaning of the United States Bankruptcy Code.

10.6. The Non-Defaulting Party's remedies under this Section 10 are the sole and exclusive remedies of the Non-Defaulting Party with respect to the occurrence of any Early Termination Date. Each party reserves to itself all other rights, setoffs, counterclaims and other defenses that it is or may be entitled to arising from the Contract.

10.7. With respect to this Section 10, if the parties have executed a separate netting agreement with close-out netting provisions, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 11. FORCE MAJEURE

11.1. Except with regard to a party's obligation to make payment(s) due under Section 7, Section 10.4, and Imbalance Charges under Section 4, neither party shall be liable to the other for failure to perform a Firm obligation, to the extent such failure was caused by Force Majeure. The term "Force Majeure" as employed herein means any cause not reasonably within the control of the party claiming suspension, as further defined in Section 11.2.

11.2. Force Majeure shall include, but not be limited to, the following: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe; (ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption and/or curtailment of Firm transportation and/or storage by Transporters; (iv) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars; and (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance.

11.3. Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (i) the curtailment of interruptible or secondary Firm transportation unless primary, in-path, Firm transportation is also curtailed; (ii) the party claiming excuse failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; or (iii) economic hardship, to include, without limitation, Seller's ability to sell Gas at a higher or more advantageous price than the Contract Price, Buyer's ability to purchase Gas at a lower or more advantageous price than the Contract Price, or a regulatory agency disallowing, in whole or in part, the pass through of costs resulting from this Agreement; (iv) the loss of Buyer's market(s) or Buyer's inability to use or resell Gas purchased hereunder, except, in either case, as provided in Section 11.2; or (v) the loss or failure of Seller's gas supply or depletion of reserves, except, in either case, as provided in Section 11.2. The party claiming Force Majeure shall not be excused from its responsibility for Imbalance Charges.

11.4. Notwithstanding anything to the contrary herein, the parties agree that the settlement of strikes, lockouts or other industrial disturbances shall be within the sole discretion of the party experiencing such disturbance.

11.5. The party whose performance is prevented by Force Majeure must provide Notice to the other party. Initial Notice may be given orally; however, written Notice with reasonably full particulars of the event or occurrence is required as soon as reasonably possible. Upon providing written Notice of Force Majeure to the other party, the affected party will be relieved of its obligation, from the onset of the Force Majeure event, to make or accept delivery of Gas, as applicable, to the extent and for the duration of Force Majeure, and neither party shall be deemed to have failed in such obligations to the other during such occurrence or event.

11.6. Notwithstanding Sections 11.2 and 11.3, the parties may agree to alternative Force Majeure provisions in a Transaction Confirmation executed in writing by both parties.

SECTION 12. TERM

This Contract may be terminated on 30 Day's written Notice, but shall remain in effect until the expiration of the latest Delivery Period of any transaction(s). The rights of either party pursuant to Section 7.6 and Section 10, the obligations to make payment hereunder, and the obligation of either party to indemnify the other, pursuant hereto shall survive the termination of the Base Contract or any transaction.

SECTION 13. LIMITATIONS

FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY. A PARTY'S LIABILITY HEREUNDER SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, A PARTY'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY. SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

SECTION 14. MISCELLANEOUS

14.1. This Contract shall be binding upon and inure to the benefit of the successors, assigns, personal representatives, and heirs of the respective parties hereto, and the covenants, conditions, rights and obligations of this Contract shall run for the full term of this Contract. No assignment of this Contract, in whole or in part, will be made without the prior written consent of the non-assigning party (and shall not relieve the assigning party from liability hereunder), which consent will not be unreasonably withheld or delayed; provided, either party may (i) transfer, sell, pledge, encumber, or assign this Contract or the accounts, revenues, or proceeds hereof in connection with any financing or other financial arrangements, or (ii) transfer its interest to any parent or affiliate by assignment, merger or otherwise without the prior approval of the other party. Upon any such assignment, transfer and assumption, the transferor shall remain principally liable for and shall not be relieved of or discharged from any obligations hereunder.

14.2. If any provision in this Contract is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Contract.

14.3. No waiver of any breach of this Contract shall be held to be a waiver of any other or subsequent breach.

14.4. This Contract sets forth all understandings between the parties respecting each transaction subject hereto, and any prior contracts, understandings and representations, whether oral or written, relating to such transactions are merged into and superseded by this Contract and any effective transaction(s). This Contract may be amended only by a writing executed by both parties.

14.5. The interpretation and performance of this Contract shall be governed by the laws of the jurisdiction as indicated on the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction.

14.6. This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any governmental authority having jurisdiction over the parties, their facilities, or Gas supply, this Contract or transaction or any provisions thereof.

14.7. There is no third party beneficiary to this Contract.

14.8. Each party to this Contract represents and warrants that it has full and complete authority to enter into and perform this Contract. Each person who executes this Contract on behalf of either party represents and warrants that it has full and complete authority to do so and that such party will be bound thereby.

14.9. The headings and subheadings contained in this Contract are used solely for convenience and do not constitute a part of this Contract between the parties and shall not be used to construe or interpret the provisions of this Contract.

14.10. Unless the parties have elected on the Base Contract not to make this Section 14.10 applicable to this Contract, neither party shall disclose directly or indirectly without the prior written consent of the other party the terms of any transaction to a third party (other than the employees, lenders, royalty owners, counsel, accountants and other agents of the party, or prospective purchasers of all or substantially all of a party's assets or of any rights under this Contract, provided such persons shall have agreed to keep such terms confidential) except (i) in order to comply with any applicable law, order, regulation, or exchange rule, (ii) to the extent necessary for the enforcement of this Contract, (iii) to the extent necessary to implement any transaction, or (iv) to the extent such information is delivered to such third party for the sole purpose of calculating a published index. Each party shall notify the other party of any proceeding of which it is aware which may result in disclosure of the terms of any transaction (other than as permitted hereunder) and use reasonable efforts to prevent or limit the disclosure. The existence of this Contract is not subject to this confidentiality obligation. Subject to Section 13, the parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with this confidentiality obligation. The terms of any transaction hereunder shall be kept confidential by the parties hereto for one year from the expiration of the transaction.

In the event that disclosure is required by a governmental body or applicable law, the party subject to such requirement may disclose the material terms of this Contract to the extent so required, but shall promptly notify the other party, prior to disclosure, and shall cooperate (consistent with the disclosing party's legal obligations) with the other party's efforts to obtain protective orders or similar restraints with respect to such disclosure at the expense of the other party.

14.11 The parties may agree to dispute resolution procedures in Special Provisions attached to the Base Contract or in a Transaction Confirmation executed in writing by both parties.

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

EXHIBIT A

Letterhead/Logo	Date: ____________ Transaction Confirmation #: ____________

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated ____________. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt unless otherwise specified in the Base Contract.

SELLER:	**BUYER:**
____________	____________
____________	____________
____________	____________
Attn: ____________	Attn: ____________
Phone: ____________	Phone: ____________
Fax: ____________	Fax: ____________
Base Contract No. ____________	Base Contract No. ____________
Transporter: ____________	Transporter: ____________
Transporter Contract Number: ____________	Transporter Contract Number: ____________

Contract Price: $______/MMBtu or ____________

Delivery Period: Begin: ____________ End: ____________

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):	**Firm (Variable Quantity):**	**Interruptible:**
______ MMBtus/day ☐ EFP	______ MMBtus/day Minimum ______ MMBtus/day Maximum subject to Section 4.2. at election of ☐ Buyer or ☐ Seller	Up to ______ MMBtus/day

Delivery Point(s): ____________
(If a pooling point is used, list a specific geographic and pipeline location):

Special Conditions:

Seller: ____________	Buyer: ____________
By: ____________	By: ____________
Title: ____________	Title: ____________
Date: ____________	Date: ____________

Appendix 5

KeySpan New England Natural Gas Price Risk Management Plan

EnergyNorth Natural Gas, Inc.

d/b/a KeySpan Energy Delivery New England

Natural Gas Price Risk Management Plan

INTRODUCTION

In recent years, prices in the natural gas commodity market have become some of the most volatile of all traded commodities. As a result, EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England ("Company") has seen its firm cost of gas fluctuate dramatically from month-to-month and year-to-year. A substantial portion of the Company's gas supply is priced based on market indices, (referred to as being "index priced"). In response to this market volatility, the Company has implemented and periodically updated a Natural Gas Price Risk Management Plan (the "Plan"). This statement of the Plan is intended to supersede all prior versions that have previously been adopted. The Plan uses various financial risk management tools and underground storage inventories in order to provide more price stability in the cost of gas to firm sales customers and to fix the cost of gas for participants in the Company's Fixed Price Option Program[1].

PLAN TERM

This Plan will become effective when authorized by the Company's Risk Management Committee and approved by the New Hampshire Public Utilities Commission.

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[1] See the "EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery New England Fixed Price Option Program" approved by the New Hampshire Public Utilities Commission.

GUIDELINES

Risk Management Tools

The Company may use derivatives (swaps, call and put options) to hedge the prices for a portion of its gas supply portfolio for the period from October through May. The portions of the portfolio that it may hedge are the flowing gas supplies that are indexed priced. The derivatives used in the hedge may be either physical or financial.

The Company will also use its underground storage capacity to mitigate price volatility by purchasing gas in approximately equal monthly increments during the April to October refill season at market prices in effect at the time, and withdrawing (and, to the extent necessary, refilling) inventories during the November to April heating season in order to maintain underground storage inventories as of each month-end that are at least equal to its annual rule-curve criteria. Withdrawals of underground storage gas shall be at the weighted average cost of gas in inventory.

Price and Volume Guidelines

The Company will hedge up to 67.5% of its index-priced supplies and up to 20% of its underground storage capacity (in addition to hedging through the refill of underground storage during the period April to October).

The Company will hedge up to 67.5% of the Gulf Coast and Canadian supplies (i.e. the index-priced supplies) purchased for delivery to its firm sales customers during the winter period months of November through April and the summer period months of May and October. At a minimum the Company will hedge the winter period volumes according to the following cumulative targets: (Hedged volume can be up to 2% below target.)

- August1 (15 months prior to the winter season) 19% of total strategy volume
- November1 (12 months prior to the winter season) 38% of total strategy volume
- February1 57% of total strategy volume
- May1 76% of total strategy volume
- August 1 95% of total strategy volume

- September 1 100% of total strategy volume

Due to the timing of the purchases made in 2005, for the 2005/2006 winter period only 87% of the total strategy volume will be hedged by August 1.

The percentage of index-priced supplies that will be hedged at any time will depend on the current natural gas market price trends relative to historical prices for winter period deliveries, forward price and volatility curves, and economic forecasts. The Company will not hedge more than 67.5% of its forecasted index-based supplies for the entire winter period, and not less than 30% or more than 80% for any month of the winter period.

The Company will further hedge the cost of its underground storage supplies by entering into arrangements between May and April to fix the cost of up to 20% of the volumes to be injected into storage during the following May through October (i.e. volumes hedged in August are for injection into storage during the following May through October injection period). At a minimum the Company will hedge storage volumes according to the following cumulative targets: (Hedged volume can be up to 2% below target.)

- By August 1 25% of the hedged underground storage capacity
- By November 1 50% of the hedged underground storage capacity
- By February 1 75% of the hedged underground storage capacity
- By May 1 100% of the hedged underground storage capacity

The Company will not hedge more than 20% of its forecasted underground storage capacity injections.

Transaction Execution Guidelines

A specific strategy for hedging the cost of gas supplies will be presented and approved by the Company's Commodity Management Committee ("CMC"). The hedging strategy will incorporate the types of transactions, timing and option premium expenditures.

Upon execution of a transaction, a trade ticket will be generated and entered into the Company's risk and transaction management system. A weekly report summarizing the transactions and the status of the hedging strategy will be distributed to, and reviewed by the CMC members. The weekly report will give the status of the hedging strategy and a Mark-to-Market position as well as other risk metrics as deemed appropriate by the Risk Controller and approved by the Chief Risk Officer

REGULATORY TREATMENT

For the index-priced gas supplies, the Company will credit the Cost of Gas Adjustment (the "COG") for the amount of any premiums received from the sale of options. Additionally, premiums paid for the purchase of options and brokerage fees will be charged to the COG. These costs will be charged to the COG period for which an option was purchased and sold (i.e., options pertaining to the months of November through April will be charged to the winter period COG, and options pertaining to the months of May through October will be charged to the summer period COG).

For the underground storage supply purchases, the Company will credit such premiums received from the sale of options to the average inventory cost of the underground storage supplies. Additionally, premiums paid for the purchase of options and brokerage fees for underground storage gas will be charged to the average inventory cost of underground storage supplies. These credits and costs will be billed to firm sales customers through the COG in the period during which the underground storage gas is withdrawn from storage and delivered to customers. Any derivative settlement payables or receivables associated with the physical purchase of natural gas will be deemed to be a recoverable cost of gas for the period hedged.

POLICIES, PROCEDURES AND CONTROLS

The Company will maintain a utility Commodity Management Committee and a Risk Management Committee. The CMC will be chaired by the Risk Controller and shall include:

- Risk Controller for Commodity Risk Management Activities
- Chief Accounting Officer
- Officer responsible for Energy Transaction Management Group
- Chief Auditor
- any others appointed by the Risk Management Committee

The CMC shall:

- Provide a forum to discuss risk management issues related to Commodity Management Activities
- Recommend to the risk management Committee for approval of broad strategies for trading and hedging and other use of derivatives
- Establish market risk limits subordinate to any market risk limits established by the Risk Management Committee, as necessary, and establish and recommend the market risk limit structures such as the determination of permitted and restricted trading activities
- Review new products and activities involving trading and the recommend the corresponding approval process through direct approval from the Risk Management Committee.

The Risk Management Committee will be chaired by the Chief Risk Officer and include:

- Chief Operating Officer
- Executive Vice President and General Counsel
- Executive Vice President and Chief Financial Officer
- Executive Vice President of Strategic Services

- President of KeySpan Energy Delivery & Customer Relationship Group
- President of KeySpan Energy Assets & Supply Group
- Other officers as designated by the Chief Executive Officer.

The Risk Management Committee shall:

- Oversee the ongoing development of this Policy to ensure that appropriate risk management methodologies are applied to the Company's business activities; monitor and enforce compliance with the Policy; approve specific exceptions to this Policy.

- Approve risk management strategy proposals in support of financial and strategic plans, including consideration of risk exposure assessment, risk mitigation, monitoring, reporting and control requirements.

- Establish risk management priorities, processes and procedures to ensure that the Company's risk-taking activities are consistent with its Risk Appetite.

- As requested by the Chief Risk Officer, approve specific risk management procedures and determine how often specific risk metrics are calculated and reported; establish risk limits and other risk control mechanisms and processes.

- Approve key roles and responsibilities within the risk management framework; evaluate whether transacting and risk management personnel are appropriately skilled.

- Provide guidance on the Finance Department's and Strategic Planning & Performance Department's Enterprise Risk Management projects and priorities; periodically engage Internal Audit in an independent audit of risk control processes and procedures.

- Assess and recommend to the Resource Allocation Committee the allocation of resources necessary for the Company's risk management activities to support its business activities.

Appendix 6

KeySpan New England
Sample
"Game Plan"

	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY
DAY OF WEEK:	[illegible]	[illegible]	[illegible]	[illegible]
DATE:	30-Nov-05	01-Dec-05	02-Dec-05	03-Dec-05
LOGAN AV.TEMP	52	41	35	31
DEGREE DAYS	13	24	30	34
LOGAN EFF. DD	15	25	35	39
AGT SENDOUT	152.379	209.852	260.210	262.094
AGT INTERUPT	0.000	0.000	0.000	0.000
TRIGEN	0.000	0.000	0.000	0.000
MYSTIC/SEVEN	0.000	0.000	0.000	0.000
NEW BOSTON	0.000	0.000	0.000	0.000
DISRT TO U ST	0.000	0.000	0.000	0.000
POTTER ST.	0.000	0.000	0.000	0.000
COLONIAL	0.000	0.000	0.000	0.000
ACTON	4.000	4.000	4.000	4.000
SUBTOTAL	148.379	205.852	256.210	258.094
CAPE DIVISION EDD	13	25	35	33
CAPE SENDOUT	20.324	29.398	37.786	37.082
CAPE INTERUPT	0.000	0.000	0.000	0.000
SUBTOTAL	20.324	29.398	37.786	37.082
LOGAN EFF DD	15	26	35	39
TGT SENDOUT	77.427	110.765	139.951	141.926
TGT INTERUPT	0.000	0.000	0.000	0.000
GERW	0.000	0.000	0.000	0.000
PP & L	0.000	0.000	0.000	0.000
ACTON	4.000	4.000	4.000	4.000
SUBTOTAL	81.427	114.765	143.951	145.926
ESSEX EDD	18	29	37	38
ESSEX SENDOUT	15.902	22.125	25.999	26.317
ESSEX INTERUPT	0.000	0.000	0.000	0.000
SUBTOTAL	15.902	22.125	25.999	26.317
LOWELL EDD	18	29	37	38
LOWELL SENDOUT	30.890	50.614	61.895	57.480
LOWELL INTERUPT	0.000	0.000	0.000	0.000
L'ENERGIA	0.000	0.000	0.000	0.000
PEPPERELL	0.000	0.000	0.000	0.000
LOWELL COGEN	0.000	0.000	0.000	0.000
SHEA RD.	0.000	0.000	0.000	10.000
SUBTOTAL	30.890	50.614	61.895	67.480
ENERGY NORTH EDD	17	27	36	38
ENERGY NORTH SO	38.978	52.330	67.490	66.065
EN NOR INTERUPT	0.000	0.000	0.000	0.000
SUBTOTAL	38.978	52.330	67.490	66.055
AGT DEMAND	168.7	235.2	293.9	296.0
TGT DEMAND	172.9	239.9	300.1	295.8
TGT FIRM S.O.	341.6	475.1	594.0	590.9
TOTAL SENDOUT	341.6	475.1	594.0	590.9
AGT Backoffs	0.000	0.000	0.000	0.000
TGT Backoffs	30.385	0.000	0.000	0.000
Distrigas to M7	33.000	0.000	0.000	0.000
AGT EST PIPELINE	187	187	187	187
TGP EST PIPELINE	103	203	203	203
DGAS MAKE	89	18	18	18
B->M	15	29	74	72
M->B	0	0	0	0

AGT TOTAL 186.761

TGT TOTAL 163.171

BGC SYSTEM

DEMAND= 341.601

SUPPLY= 408.836

BALANCE 67.235

DOMAC 88.904

COMM PT. 1

Cape LNG 0

Whitman 0

HAVERHILL 0

Lowell LNG 1

Energy North 0

PA/Mob. LNG 0

LYNN 1

SALEM 0

AGT HI = 0.474

TGT HI = 3.274

ESSEX= 0.015

ENG NORTH 1.275

Lowell HI = 1.260

CAPE HI = 0.964

Total HI 12.565

W/B MAX = 60.00

1.000 0.870 0.880 1.050 0.948 1.000

TUESDAY

29-Nov-05

SFDO VER.

9

SOURCE: AGT	WED	THU	FRI	SAT
BGC-CANADIAN	0.000	0.000	0.000	0.000
BGC-BASE LOAD	81.000	81.000	81.000	81.000
BGC-SWING	38.000	38.000	38.000	38.000
BGC-HUBLINE 10K Tier V	0.000	0.000	0.000	0.000
BGC-STORAGE	0.000	0.000	0.000	0.000
BGC-PROVIDENCE LNG	0.000	0.000	0.000	0.000
BGC-SPOT/IT	0.000	0.000	0.000	0.000
BGC - FT	41.930	41.930	41.930	41.930
BGC-EXELON	0.000	0.000	0.000	0.000
SUBTOTAL	160.930	160.930	160.930	160.930
CAPE COD-CANADIAN	5.641	5.641	5.641	5.641
CAPE COD-BASELOAD	15.000	15.000	15.000	15.000
CAPE COD-SWING	2.000	2.000	2.000	2.000
CAPE COD-SPOT	0.000	0.000	0.000	0.000
CAPE COD-HUBLINE 10K	0.000	0.000	0.000	0.000
CAPE COD-STORAGE	0.000	0.000	0.000	0.000
CAPE COD-DOMAC 15K	0.000	0.000	0.000	0.000
CAPE-PROVIDENCE LNG	0.000	0.000	0.000	0.000
CAPE COD-IT / FT	3.190	3.190	3.190	3.190
SUBTOTAL	25.831	25.831	25.831	25.831
AGT OBA	0.000	0.000	0.000	0.000
AGT TOTAL	186.761	186.761	186.761	186.761
SOURCE: TGT				
BGC-CANADIAN	54.660	54.660	54.660	54.660
BGC-BASELOAD	21.326	21.326	21.326	21.326
BGC-SWING	15.000	15.000	15.000	15.000
BGC-STORAGE	0.000	0.000	0.000	0.000
BGC-SPOT	0.000	0.000	0.000	0.000
BGC-IT / FT	20.068	20.068	20.068	20.068
SUBTOTAL	111.054	111.054	111.054	111.054
ESSEX-CANADIAN	3.516	3.516	3.516	3.516
ESSEX-BASELOAD	3.000	3.000	3.000	3.000
ESSEX-SWING	8.000	8.000	8.000	8.000
ESSEX-STORAGE	0.000	0.000	0.000	0.000
ESSEX-SPOT	0.000	0.000	0.000	0.000
ESSEX-EGC 15K	0.000	0.000	0.000	0.000
ESSEX-DOMAC 5K	0.000	0.000	0.000	0.000
ESSEX-IT / FT	1.551	1.551	1.551	1.551
SUBTOTAL	13.067	13.067	13.067	13.067
LOWELL-CANADIAN	0.000	0.000	0.000	0.000
LOWELL-BASELOAD	5.000	5.000	5.000	5.000
LOWELL-SWING	20.000	20.000	20.000	20.000
LOWELL-STORAGE	0.000	0.000	0.000	0.000
LOWELL-SPOT	0.000	0.000	0.000	0.000
LOWELL-DOMAC 15K	0.000	0.000	0.000	0.000
LOWELL-IT / FT	7.333	7.333	7.333	7.333
LOWELL COGEN	0.000	0.000	0.000	0.000
L'ENERGIA	0.000	0.000	0.000	0.000
PEPPERELL	0.000	0.000	0.000	0.000
SUBTOTAL	32.333	32.333	32.333	32.333
E.NORTH-CANADIAN	0.781	0.781	0.781	0.781
E. NORTH-BASELOAD	16.000	16.000	16.000	16.000
E.NORTH [illegible]	0.000	0.000	0.000	0.000
E.NORTH-SWING	18.000	18.000	18.000	18.000
E.NORTH-DOMAC 5K	0.000	0.000	0.000	0.000
E.NORTH-STORAGE	0.000	0.000	0.000	0.000
E. NORTH-AES 15K	0.000	0.000	0.000	0.000
E. NORTH-IT	0.000	0.000	0.000	0.000
E. NORTH-FT	6.322	6.322	6.322	6.322
E. NORTH-SPOT	0.000	0.000	0.000	0.000
SUBTOTAL	40.103	40.103	40.103	40.103
TGT OBA	0.000	0.000	1.000	0.000
TGT TOTAL	202.557	202.557	202.557	202.557
TGT METER BOUNCE	0.000	0.000	0.000	0.000
Baystate - Whitman	0.000	0.000	0.000	0.000
Mass. LPG & Mobile LNG	0.000	0.000	0.000	0.000
Commercial Point	0.700	0.700	0.700	0.700
Cape Cod	0.900	0.900	0.800	0.300
Lynn	0.700	0.700	0.700	0.700
Salem	0.300	0.300	0.300	0.300
Haverhill	0.300	0.300	0.300	0.300
Tewksbury	0.700	0.700	0.700	0.700
Eng North Production	0.000	0.000	0.000	0.000
Distrigas SS-1	0.000	0.000	0.000	0.000
Distrigas Keyspan	0.000	0.000	0.000	0.000
Distrigas Trigen	2.750	0.000	0.000	0.000
Distl Tailgate	13.768	17.781	17.781	17.391
DISTR TO U ST	0.000	0.000	0.000	[illegible]
Distrigas to M7	33.000	0.000	0.000	0.000
AGT & TGT Backoffs	30.385	0.000	0.000	0.000
TOTAL BALANCE	67	-65	-184	-181
Energy North Balance	7	-6	-21	-20
Boston Balance	60	-59	-163	-161

Appendix 7

KeySpan New England
Sample
Daily Volume Sheet
And
On-Call Lists

SCHEDULED DELIVERIES FOR BGC, CGC, EGC AND ENERGYNORTH

		Wednesday 11/30/05	Thursday 12/01/05
ALGONQUIN			
BGC System Supply	Canadian	0	0
	Baseload	81,000	95,000
	Swing	0	25,000
	Hubline 10K	0	0
	Storage	0	0
	Hubline Tier V	0	0
	Providence LNG	0	0
	Spot	0	0
	IT Customers	0	0
	FT Customers	41,930	62,673
Sempra to Mystic 7 (meter 27)		0	0
Exelon @ L St. (meter 52)		0	0
Subtotal:		122,930	182,673
Colonial System Supply (Cape Cod)	Canadian	5,641	5,611
	Baseload	15,000	20,000
	Swing/Spot	0	0
	Hubline 10K	0	0
	Storage	0	0
	Hubline Tier V	0	0
	DOMAC 15K	0	0
	Providence LNG	0	0
	Spot	0	0
	IT Customers	0	0
	FT Customers	3,190	4,021
Subtotal:		23,831	29,632
Make-up/Payback: (BGC & CGC)		0	0
AGT Payback (not scheduled on LINK):		0	0
BGC System Supply Subtotal:		**146,761**	**212,305**
Less: DOMAC Backoff		0	0
Less: TYR Backoff		0	0
TOTAL AGT(NET OF BACKOFFS):		146,761	212,305
DOMAC Backdoor Supply (FCS064)		0	0
DOMAC Backdoor to Sempra (M7):		20,000	900
DOMAC Backdoor to Exelon (L St):		0	0
Baystate Nominations:		0	0
PNGTS			
EnergyNorth System Supply			
	Baseload	90	125
	Swing	0	0
TOTAL PNGTS		**90**	**125**

NOTE: PLEASE USE A TOLERANCE OF 110% ON THE PIPELINE.

Remaining Swing	**77,965**	**33,965**
Remaining Storage	**103,575**	**103,575**

SCHEDULED DELIVERIES FOR BGC, CGC, EGC AND ENERGYNORTH

		Wednesday 11/30/05	Thursday 12/01/05
TENNESSEE			
BGC System Supply			
	Canadian	54,660	54,668
	Baseload	21,325	23,000
	Swing	10,000	0
	Storage	0	0
	Spot	0	0
	IT Customers	0	0
	FT Customers	19,769	22,770
Subtotal:		105,754	100,438
Essex System Supply			
	Canadian	3,516	3,518
	Baseload	3,000	15,000
	Swing	5,000	0
	Storage	0	0
	Spot	0	0
	EGC 15K	0	0
	DOMAC 6K	0	0
	IT Customers	0	0
	FT Customers	1,551	1,944
Subtotal:		13,067	20,462
Colonial System Supply (Lowell)	Canadian	0	0
	Baseload	5,000	17,000
	Swing	20,000	25,000
	Storage	0	0
	Spot	0	0
	DOMAC 15K	0	0
	IT Customers	0	0
	FT Customers	7,333	8,515
	Lo Cogen	0	0
	L'Energia	0	0
	Pepperell	0	0
Subtotal:		32,333	50,515
EnergyNorth System Supply	Canadian	6,781	6,771
	Baseload	18,000	12,000
	CoEnergy 20K	0	19,822
	Swing	13,000	0
	Dracut 20K	0	0
	DOMAC 8K	0	8,000
	Storage	0	0
	AES 15K	0	0
	IT Customers	0	0
	FT Customers	8,322	9,535
	Spot	0	0
Subtotal:		46,103	56,128
Make-up/Payback:		0	0
BGC System Supply Subtotal:		$\boxed{197,257}$	$\boxed{227,543}$
Less: DOMAC Backoff		(39,386)	(39,387)
Less: Meter Bounce (Marketers)		0	0
DOMAC System Supply Backdoor		0	20,000
TOTAL TGP(NET OF DOMAC BACKOFF):		157,871	188,156
TGP TOLERANCE (2%-10%)		5%	5%
VOLUME TOLERANCE		7,894	9,408

NOTE: PLEASE USE A TOLERANCE OF 105% ON THE PIPELINE.

Remaining Consolidated Swing	75,683	60,008
Remaining EnergyNorth Swing	9,475	28,475
Remaining Consolidated Storage	98,049	98,049
Remaining EnergyNorth Storage	27,101	27,101

ON CALL LIST

DAY	DATE	PRIMARY CONTACT	BACK-UP CONTACT
FRIDAY	11/25/05	NANCY	DINO
SATURDAY	11/26/05	NANCY	DINO
SUNDAY	11/27/05	NANCY	DINO
MONDAY	11/28/05	DINO	NANCY
TUESDAY	11/29/05	DINO	NANCY
WEDNESDAY	11/30/05	DINO	NANCY
THURSDAY	12/01/05	DINO	NANCY

DIRECTORY		HOME	PAGER	OFFICE
Almeida, James			(617)-339-5455	(781) 466-5141
Almeida, James				
Arangio, Liz				(781) 466-5057
Arangio, Liz			Nextel Code-51790	
Barrett, Kathy			Nextel Phone: (617) 828-6658	(781) 466-5050
Codrescu, Claudia				(781) 466-5051
Culliford, Nancy				(781) 466-5056
Culliford, Nancy			Nextel Code-60090	
Gilbertson, Debbie				(781) 466-5061
Hedman, Jon			(617)-381-2692	(781) 466-5146
Hedman, Jon				
O'Neill, Maria			None	(781) 466-5055
Papetti, Dino			None	(781) 466-5066
Papetti, Dino				
Poe, Ted				(781) 466-5067
Querzoli, Dawn				(781) 466-5068
Torok, Claudia				(781) 466-5051
Whitney, Debbie				
Dispatch		(781) 466-6090	Nextel Code-37999 or 38999	(781) 466-6091
				(781) 466-6092
MERRILL LYNCH		**HOME**	**OFFICE**	**CELL PHONE**
Monica Gallager	MGR. Scheduling	Merrill office phones automatically page after you leave a message.	713-544-6013	713-327-3533
John Mueller			713-544-4000	713-898-2810
Cara Starnes (TGP)	Scheduler		713-544-5521	713-825-5474
Cathy Robbins (TGP) (Backup)	Scheduler		713-544-4276	713-806-1767
Cassie Burton (AGT) (Primary)	Scheduler		713-544-4856	713-817-3567
Carol Durisko (AGT)	Scheduler		713-544-6651	713-205-3429
Courtney Zenner (TGP) (Primary)	Scheduler		713-544-5729	713-817-1904
Jamila Tanner (AGT) (Backup)	Scheduler		713-544-7757	713-819-4442
David Stratton	Trader		713-544-4400	713-817-8708 (Cell)

***Entergy Koch Office phones automatically page after you leave a message.

AGT/TETCO MARITIMES			
Shift person			(713) 627-5058
Dispatch			(800) 726-8383
Distrigas			
Lou DePrizio			(617) 381-8567
Tim Madden			(617) 381-8532
BGC/CGC-Managed Storages			
Answering Service-Honeoye	(716) 657-6565	None	
On-Call Person-Nat'l Fuel-Hon	(716) 827-2385	(716) 642-8700	
Dominion Gas Transmission	(804)-819-2861		
	(804)-819-2851		
KLNG			
KeySpan LNG			(401) 785-4590
AES			
John Woodham			(703) 292-0828
			(571) 277-0224 (cell)
COEnergy/DTE - ENGI			
On Call Pager			(800)-506-9857
Tennessee Gas Pipeline			
24 Shift Analyst			(713) 420-4999

KEYSPAN

KeySpan Energy Utility Services LLC
100 East Old Country Road
Hicksville, NY 11801

November 23, 2005

The following contact sheet should be used for resolving questions or problems that may arise outside of normal working hours.

	Work Phone	Pagers/Cell *	Home Phone
Gas – Energy Transactions Organization (ETO)			
Mark Leippert – Dir.	545-5412	(516) 376-7172	(631) 864-4930
John Metress – Mgr.	546-5425	(516) 458-1165	(516) 763-9268
Rich Kunz – Mgr.	545-5411	(516) 319-2602	(631) 754-7104
Mark Kulick	545-5415	(516) 376-7173	(631) 598-3958
Pat Hoeler	545-5413	(516) 376-7173	(631) 234-8429
Rashi Dahl	545-5431	(516) 824-2189	(631) 486-8121
A.J. Poletski	545-5430	(516) 376-7173	(631) 586-4108
Kirsten Richards	545-5410	(516) 376-7179	(631) 940-0908
Michael Scollan	545-5453	(516) 376-7173	(631) 567-1070
Wen Wen	545-5434	(516) 376-7173	(212) 619-0890

Cell Phone – Gas (516) 376-7173

	Work Phone	Pagers/Cell *	Home Phone
Gas Supply Planning			
Kevin Marino	545-5422	(917) 298-9745	(516) 783-4771
Faye Allicock	546-5424	(917) 331-1425	(718) 975-7005

Appendix 8

KeySpan New England
Sample
BMS Nominations Template

Nominations

Marketer: **Marketer ID:** #N/A

Month Of: December-05

Keyspan Company: **Company ID:** #N/A

Pipeline: **Pipeline ID:** #N/A

Service Type: **Pipeline Contract:** **Meter Number:** **Point Name:**	Daily A0001 10001 Domac - AGT	Invalid Combination	Invalid Combination	Invalid Combination
1-Dec-2005	0	0	0	0
2-Dec-2005	0	0	0	0
3-Dec-2005	0	0	0	0
4-Dec-2005	0	0	0	0
5-Dec-2005	0	0	0	0
6-Dec-2005	0	0	0	0
7-Dec-2005	0	0	0	0
8-Dec-2005	0	0	0	0
9-Dec-2005	0	0	0	0
10-Dec-2005	0	0	0	0
11-Dec-2005	0	0	0	0
12-Dec-2005	0	0	0	0
13-Dec-2005	0	0	0	0
14-Dec-2005	0	0	0	0
15-Dec-2005	0	0	0	0
16-Dec-2005	0	0	0	0
17-Dec-2005	0	0	0	0
18-Dec-2005	0	0	0	0
19-Dec-2005	0	0	0	0
20-Dec-2005	0	0	0	0
21-Dec-2005	0	0	0	0
22-Dec-2005	0	0	0	0
23-Dec-2005	0	0	0	0
24-Dec-2005	0	0	0	0
25-Dec-2005	0	0	0	0
26-Dec-2005	0	0	0	0
27-Dec-2005	0	0	0	0
28-Dec-2005	0	0	0	0
29-Dec-2005	0	0	0	0
30-Dec-2005	0	0	0	0
31-Dec-2005	0	0	0	0
Total	0	0	0	0

Appendix 9

KeySpan New England
Sample
Scheduled Daily Deliveries Report

KeySpan Energy Delivery

Energy North Gas Company

Daily Scheduled Deliveries Detail

November 30, 2005

Pipeline: Tennessee

Receipt Point		Contract Number	Service Type	Supplier	Confirmed Nominations (MMBtu)	
20132	NASHUA	081498750	O - Daily Metered	Amerada Hess	125	
20132	NASHUA	081498750	S - Non-Daily Metered	Amerada Hess	81	206
20132	NASHUA	178630257	O - Daily Metered	Select Energy, Inc	1,165	
20132	NASHUA	178630257	S - Non-Daily Metered	Select Energy, Inc.	792	1,957
20132	NASHUA	860097617	O - Daily Metered	Global Companies, LLC	320	
					2,483	
20133	MANCHESTER	131362733	O - Daily Metered	Sprague Energy Corp	1,868	
20133	MANCHESTER	178630257	S - Non-Daily Metered	Select Energy, Inc.	54	
20133	MANCHESTER	608140745	O - Daily Metered	Sprague Energy Corp	2,460	
20133	MANCHESTER	608140745	S - Non-Daily Metered	Sprague Energy Corp	40	2,500
20133	MANCHESTER	860097617	O - Daily Metered	Metromedia Energy	425	
20133	MANCHESTER	860097617	S - Non-Daily Metered	Metromedia Energy	534	959
20133	MANCHESTER	926082306	S - Non-Daily Metered	Metromedia Energy	286	
					5,667	
20426	LACONIA	131362733	O - Daily Metered	Sprague Energy Corp	23	
20426	LACONIA	178630257	S - Non-Daily Metered	Select Energy, Inc.	71	
20426	LACONIA	926082306	S - Non-Daily Metered	Metromedia Energy	78	
					172	
				Grand Total:		8,322

Appendix 10

KeySpan New England
Sample
Monthly Sendout Report

ENERGY NORTH - OCTOBER 2005
SENDOUTS

	NASHUA	MANCHEST	HOOKSETT	concord LACONIA	SUNCOOK	LONDON	BERLIN	TOTAL PIPE	PROPANE	VAPOR	BOILOFF	TOTAL SENDOUT	AVG TEMP	EDD	ZONE 9
1	5965	3884	200	3443	229	1892	41	15654	0	0	53	15707	58	7	1050
2	5880	3622	371	3315	198	2195	45	15626	0	0	53	15679	62	5	1051
3	5896	3783	532	4189	361	2117	51	16929	0	0	53	16982	62	4	1048
4	5749	4114	547	4219	287	1924	40	16880	0	0	53	16933	62	5	1049
5	5497	4848	508	3851	307	1493	41	16545	0	0	53	16598	66	1	1056
6	5241	5409	410	2807	312	997	36	15212	0	0	53	15265	70	0	1048
7	4787	4130	189	2518	254	1671	36	13585	0	0	53	13638	74	0	1037
8	5389	4729	126	3358	264	1759	57	15682	0	0	53	15735	56	11	1037
9	6652	5759	143	4074	334	1571	76	18609	0	0	53	18662	54	12	1035
10	7381	6363	228	5033	314	1570	54	20943	0	0	52	20995	55	10	1046
11	7957	6203	495	5307	158	2267	56	22443	0	0	52	22495	54	12	1048
12	9275	7947	642	6078	244	2004	53	26243	0	0	52	26295	52	14	1049
13	8380	7591	498	5859	316	1926	59	24629	0	0	52	24681	55	11	1052
14	7133	6523	351	5157	207	1797	48	21216	0	0	52	21268	57	9	1050
15	7644	6252	243	4635	358	2272	48	21452	0	0	52	21504	54	12	1048
16	9424	7549	313	5544	473	2500	60	25863	0	0	52	25938	54	13	1047
17	9458	7589	545	5951	467	2338	80	28426	0	0	52	28478	52	14	1046
18	9492	8288	748	5924	384	2052	62	26950	0	0	52	27002	53	13	1045
19	9470	7952	631	6215	480	1949	84	26781	0	0	52	26833	54	12	1043
20	13204	10263	737	8399	722	2489	89	35903	0	0	52	35955	44	22	1046
21	13376	10593	781	8475	789	2242	92	36308	0	0	52	36360	44	22	1036
22	14226	11746	650	7981	565	1828	71	37047	0	0	52	37099	44	23	1031
23	14499	11813	420	8028	755	1899	86	37500	0	0	52	37552	44	22	1047
24	16476	11369	556	8235	680	2667	74	40057	0	0	52	40109	46	21	
25	19565	13710	586	10184	744	3088	99	47936	0	0	52	47988	40	28	
26	19807	13687	694	9661	789	2900	101	47619	0	0	52	47671	42	25	
27								0	0	0	52	52			
28								0	0	0	52	52			
29								0	0	0	52	52			
30								0	0	0	52	52			
31								0	0	0	52	52			
	247823	195716	12124	148400	10951	53385	1639	670038	0	0	1621	671682	54	328	1045

Appendix 11

KeySpan New England
Sample
Daily Imbalance Report

IMBALANCE
OCTOBER 2005
ENERGY NORTH

DAY	NOMINATION RECEIPT	ACTUAL DELIVERY	DAILY IMBALANCE	ACCUML'TVE IMBALANCE
				0
1	14,993	15,612	619	619
2	15,279	15,580	301	920
3	16,851	16,878	27	947
4	12,711	16,840	4,129	5,076
5	16,023	16,502	479	5,555
6	16,463	15,176	-1,287	4,268
7	14,064	13,548	-516	3,752
8	20,278	15,625	-4,653	-901
9	19,058	18,534	-524	-1,425
10	20,435	20,889	454	-971
11	20,701	22,387	1,686	715
12	26,109	26,190	81	796
13	23,930	24,570	640	1,436
14	26,500	21,168	-5,332	-3,896
15	20,220	21,405	1,185	-2,711
16	26,072	25,803	-269	-2,980
17	27,250	26,346	-904	-3,884
18	27,177	26,887	-290	-4,174
19	24,424	26,698	2,274	-1,900
20	33,289	35,814	2,525	625
21	31,809	36,217	4,408	5,033
22	38,122	36,975	-1,147	3,886
23	43,567	37,414	-6,153	-2,267
24	40,227	39,983	-244	-2,511
25	39,522	47,836	8,314	5,803
26	45,968	47,518	1,550	7,353
27			0	7,353
28			0	7,353
29			0	7,353
30			0	7,353
31			0	7,353
	661,042	668,395	7,353	

Appendix 12

KeySpan New England
Sample
Monthly Asset Manager
Reports/Invoices

EnergyNorth Supply and Transport

Gas Day	CANADIAN SUPPLY Canada Volume ANE	ANE Commodity TC	ANE Cost TGP	Canada Volume @ Ratio	Commodity TGP	Cost TGP	DRACUT SUPPLY Baseload Volume TGP	Baseload Commodity TGP	Baseload Price TGP	BASELOAD SUPPLY Baseload Volume	Baseload Price TGP	Baseload Cost TGP	SWING SUPPLY Swing Volume TGP	Swing Price TGP	Swing Cost TGP	STORAGE WITHDRAWAL Storage Injected TGP	Storage Delivered TGP	Storage Commodity TGP	PORTLAND NATURAL GAS Baseload Volume PNGTS	Baseload Price PNGTS	Baseload Cost PNGTS	Volume Totals	Cost Totals
1-Dec-05	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2-Dec-05	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3-Dec-05	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TENNESSEE

Swing Supply

	Swing Supply	Swing Index			fuel	commodity			
1	Zn 1, 100 Leg TENNESSEE to Zone 6 TENNESSEE	0.00%	$	-	7.82%	$	-	$	-
2	Zn 0, 100 Leg TENNESSEE to Zone 6 TENNESSEE	0.00%	$	-	7.82%	$	-	$	-
3	Zn 1, 800 Leg TENNESSEE to Zone 6 TENNESSEE	0.00%	$	-	8.71%	$	-	$	-
4	Zn 1, 500 Leg TENNESSEE to Zone 6 TENNESSEE	0.00%	$	-	7.82%	$	-	$	-
5	Tennessee Dracut	0.00%	$	-	7.82%	$	-	$	-
		0.00%						$	-

Baseload Supply

	Baseload Supply	Baseload Index			fuel	commodity			
1	Zn 1, 100 Leg TENNESSEE to Zone 6 TENNESSEE	0.00%	$	-	7.82%	$	-	$	-
2	Zn 0, 100 Leg TENNESSEE to Zone 6 TENNESSEE	0.00%	$	-	7.82%	$	-	$	-
3	Zn 1, 800 Leg TENNESSEE to Zone 6 TENNESSEE	0.00%	$	-	8.71%	$	-	$	-
4	Zn 1, 500 Leg TENNESSEE to Zone 6 TENNESSEE	0.00%	$	-	7.82%	$	-	$	-
5	Tenn Dracut	0.00%	$	-	7.82%	$	-	$	-
		0.00%						$	-

Dracut Supply

Tenn Dracut (agreed upon pricing)	100.00%	$	-	0.00%	$	-	$ -

Keyspan Consolidated Demand & Reservation Charges

TRANSPORTATION			Oct-05				Actual
Company	Pipeline	Rate Schedule	Counterparty Contract#	MLCI Contract #	Demand Rate	MDQ	Demand Charges paid by Keyspan
Energy North	Nat Fuel	FST	N02358	B10229/122351	$ 0.0832	5,869	$ 488.30
Energy North	PNGTS	RD1	FT-1999-001	CR-2004-010	$ 28.8542	1,000	$ 28,854.20
Energy North	TGPL	FT-A	11234 FTA	49296	$ 5.6821	8,700	$ 49,434.27
Energy North	TGPL	FT-A	42076 FTA	49297	$ 3.1600	19,192	$ 60,646.72
Energy North	TGPL	FT-A	632 FTA	49299	$ 5.8900	14,694	$ 86,547.66
Energy North	TGPL	FT-A	8587 FTA	49310	$ 14.1561	24,392	$ 345,295.59
							$ 568,266.74

STORAGE			Oct-05						Actual
Company	Pipeline	Rate Schedule	Counterparty Contract#	MLCI Contract#	Demand Charge	Space Charge	Storage Capacity	MDQ	Demand Charges paid by Keyspan
Energy North	Dominion	GSS	300076	533417	$ 1.8822	$ 0.0149	98,656	899	$ 3,125.51
Energy North	Nat Fuel	ESS	N002357	R10233/122381	$ 2.1556	$ 0.0432	845,894	5,089	$ 40,545.20
Energy North	TGPL	FS-MA	523 FSMA	49309	$ 1.1500	$ 0.0185	1,501,989	21,026	$ 51,966.70
									$ 95,637.41

Total Consolidated Transportation & Storage $ 663,904.15

Appendix 13

KeySpan New England
Sample
Monthly Storage Report

Energy North
Receipt (Storage) Numbers

Fuel Recip	11/1/2005				1/6/2005
	2.09%	2.17%	2.17%	1.92%	
MSQ	235,339	643,612	1,497,146	98,538	2,474,635
Beg Bal:	234,646	641,716	1,492,737	98,247	2,467,345
% Full	100%	100%	100%	100%	100%
Gas Day	HONEOYE TGP	NF - FSS TGP	FSMA TGP	DTI GSS TGP	PAPER TOTALS
11/1/2005	-	-	-	-	-
11/2/2005	-	-	-	-	-
11/3/2005	-	-	-	-	-
11/4/2005	-	-	-	-	-
11/5/2005	-	-	-	-	-
11/6/2005	-	-	-	-	-
11/7/2005	-	-	-	-	-
11/8/2005	-	-	-	-	-
11/9/2005	-	-	-	-	-
11/10/2005	-	-	-	-	-
11/11/2005	-	-	-	-	-
11/12/2005	-	-	-	-	-
11/13/2005	-	-	-	-	-
11/14/2005	-	-	-	-	-
11/15/2005	-	-	-	-	-
11/16/2005	-	-	-	-	-
11/17/2005	-	-	-	-	-
11/18/2005	-	-	-	-	-
11/19/2005	-	-	-	-	-
11/20/2005	-	-	-	-	-
11/21/2005	-	-	-	-	-
11/22/2005	-	-	-	-	-
11/23/2005	-	-	-	-	-
11/24/2005	-	-	-	-	-
11/25/2005	-	-	-	-	-
11/26/2005	-	-	-	-	-
11/27/2005	-	-	-	-	-
11/28/2005	-	-	-	-	-
11/29/2005	-	-	-	-	
11/30/2005	-	-	-	-	
Total Monthly (W/D)	-	0	0	-	-
Total Monthly (Inj)	-	-	-	-	-
Migration	-	-	-	-	-
In Hole Loss					
Ending Bal:	235,054	642,838	1,497,146	98,419	2,473,457
vlookup	2	3	1	4	
% full	100%	100%	100%	100%	100%

Energy North
Delivered (Citygate) Numbers

9:19 AM

Gas Day	HONEOYE TGP	NF - FSS TGP	FSMA TGP	DTI GSS TGP	PAPER TOTALS
11/1/2005					-
11/2/2005					-
11/3/2005					-
11/4/2005					-
11/5/2005					-
11/6/2005					-
11/7/2005					-
11/8/2005					-
11/9/2005					-
11/10/2005					-
11/11/2005					-
11/12/2005					-
11/13/2005					-
11/14/2005					-
11/15/2005					-
11/16/2005					-
11/17/2005					-
11/18/2005					-
11/19/2005					-
11/20/2005					-
11/21/2005					-
11/22/2005					-
11/23/2005					-
11/24/2005					-
11/25/2005					-
11/26/2005					-
11/27/2005					-
11/28/2005					-
11/29/2005					-
11/30/2005					

COMMODITY + SURCHARGES

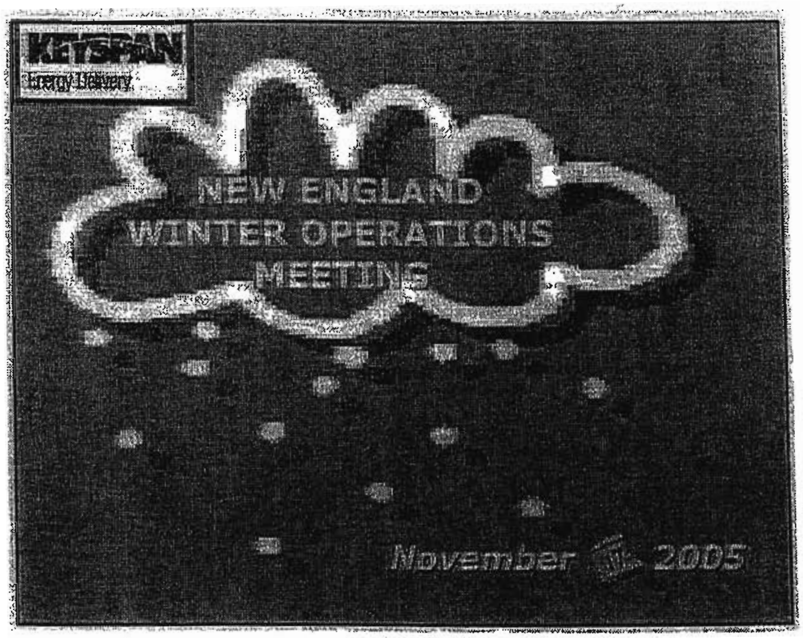
	DTI GSS	DTI GSS TE	Tetco SS1	Honeoye	Nat Fuels	Tenn FSMA
Storage	0.0177	-	-	-	0.0160	0.0102
Transport						
Dominion			0	0	0	0
Tetco		0	0	0	0	0
Tenn	0.0853	0	0	0.0784	0.0853	0.0853
Nat Fuel	0	0	0	0	0	0
Algonquin	0	0	0	0	0	0
Total	0.0853	0	0	0.0784	0.0853	0.0853

Commodity Charges

Gas Day	HONEOYE TGP	NF FSS TGP	FSMA TGP	DTI GSS TGP		TOTALS
11/1/2005	$ -	$ -	$ -	$ -		$ -
11/2/2005	$ -	$ -	$ -	$ -		$ -
11/3/2005	$ -	$ -	$ -	$ -		$ -
11/4/2005	$ -	$ -	$ -	$ -		$ -
11/5/2005	$ -	$ -	$ -	$ -		$ -
11/6/2005	$ -	$ -	$ -	$ -		$ -
11/7/2005	$ -	$ -	$ -	$ -		$ -
11/8/2005	$ -	$ -	$ -	$ -		$ -
11/9/2005	$ -	$ -	$ -	$ -		$ -
11/10/2005	$ -	$ -	$ -	$ -		$ -
11/11/2005	$ -	$ -	$ -	$ -		$ -
11/12/2005	$ -	$ -	$ -	$ -		$ -
11/13/2005	$ -	$ -	$ -	$ -		$ -
11/14/2005	$ -	$ -	$ -	$ -		$ -
11/15/2005	$ -	$ -	$ -	$ -		$ -
11/16/2005	$ -	$ -	$ -	$ -		$ -
11/17/2005	$ -	$ -	$ -	$ -		$ -
11/18/2005	$ -	$ -	$ -	$ -		$ -
11/19/2005	$ -	$ -	$ -	$ -		$ -
11/20/2005	$ -	$ -	$ -	$ -		$ -
11/21/2005	$ -	$ -	$ -	$ -		$ -
11/22/2005	$ -	$ -	$ -	$ -		$ -
11/23/2005	$ -	$ -	$ -	$ -		$ -
11/24/2005	$ -	$ -	$ -	$ -		$ -
11/25/2005	$ -	$ -	$ -	$ -		$ -
11/26/2005	$ -	$ -	$ -	$ -		$ -
11/27/2005	$ -	$ -	$ -	$ -		$ -
11/28/2005	$ -	$ -	$ -	$ -		$ -
11/29/2005	$ -	$ -	$ -	$ -		$ -
11/30/2005	$ -	$ -	$ -	$ -		$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -

Appendix 14

KeySpan New England Winter Operations 2005/2006 Presentation


KEYSPAN
Energy Delivery
NEW ENGLAND
WINTER OPERATIONS
MEETING
November 2005


KEYSPAN
Energy Delivery
Agenda
• RESOURCE PORTFOLIO
– TOTAL PIPELINE VOLUMES
– MERRILL LYNCH DEAL STRUCTURE SUMMARY
– DISTRIGAS CONTRACTS SUMMARY
• WINTER 2005 - 2006 UPDATES
– SUPPLY PLANNING
– HURRICANE UPDATES
– NHPUC 7 - DAY REQUIREMENT
– ENERGYNORTH UNDERGROUND STORAGE DISPATCH REQUIREMENT
– TRANSGAS DEDICATED TRUCKING
– FTS1 CONTRACT
• SUMMARY

KEYSPAN Energy Delivery

Resource Portfolio

	Algonquin	Tennessee	Portland	Total
Boston	311,849	242,088		553,937
Colonial	84,563	66,083		150,646
Essex	-	12,862		12,862
Subtotal	396,412	321,033		717,445
EnergyNorth	-	76,833	1,000	77,833
Total	396,412	397,866	1,000	795,278

A

Notes:

1. Boston volumes include KLNG transport of 35,000.
2. Colonial ANE 5,000 MMBtu can be delivered to either/or AGT or TGP Citygates.
3. EnergyNorth volumes DO NOT include AES peaking deal of 15,000 MMBtu/day for 30 days (450,000 total).
4. Colonial AGT-MDQ increases by 13,000 MMBtu/day

KEYSPAN Energy Delivery

Resource Portfolio

MERRILL LYNCH DEAL STRUCTURE SUMMARY					
BOSTON, COLONIAL & ESSEX			ENERGYNORTH		
Tier	Resources	Pricing	Tier [4]	Resources	Pricing
I[1]	ANE, BP & NEXEN	Contract price	I	ANE/BP/NEXEN	Contract price
I	Imperial/Maritimes	Contract price	II	Baseload	FOM Wellhead
II	Baseload	FOM Wellhead	II[3]	Baseload Dracut	FOM Dawn
III	Swing	Gas Daily Wellhead	III	Swing	Gas Daily Wellhead
IIIb[2]	Hubline	Gas Daily - Dracut, Mass	III b	DOMAC	FVS/66
IV	Storage	WACOG	IV	Storage	WACOG
V	Hubline	Mutually agreed Price			

Notes:

1. MA Tier I & Tier II are monthly baseload elections and CAN NOT be reduced.
2. Prior to the start of each month, Buyer has ability to allocate volumes up to 45,000 MMBtu between Tier IIIb and Tier V.
3. 20,000 MMBtu at Dracut considered baseload for the months of Dec 2005 through Feb 2006. No Recall Rights with CoEnergy / Nov 2005 and March 2006, 20,000 MMBtu/Day available as [illegible]
4. April 2005 agreement with MLCI allows gas to be dispatched in any order

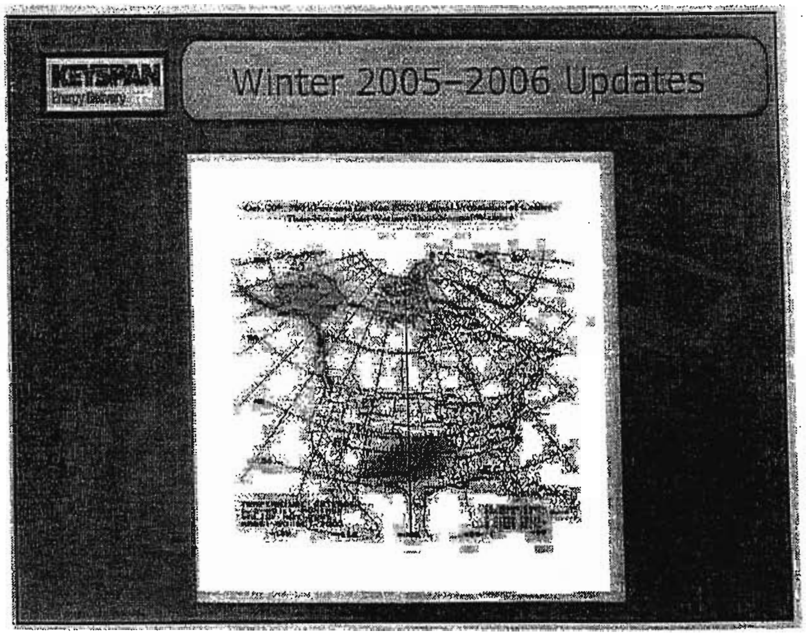
Resource Portfolio

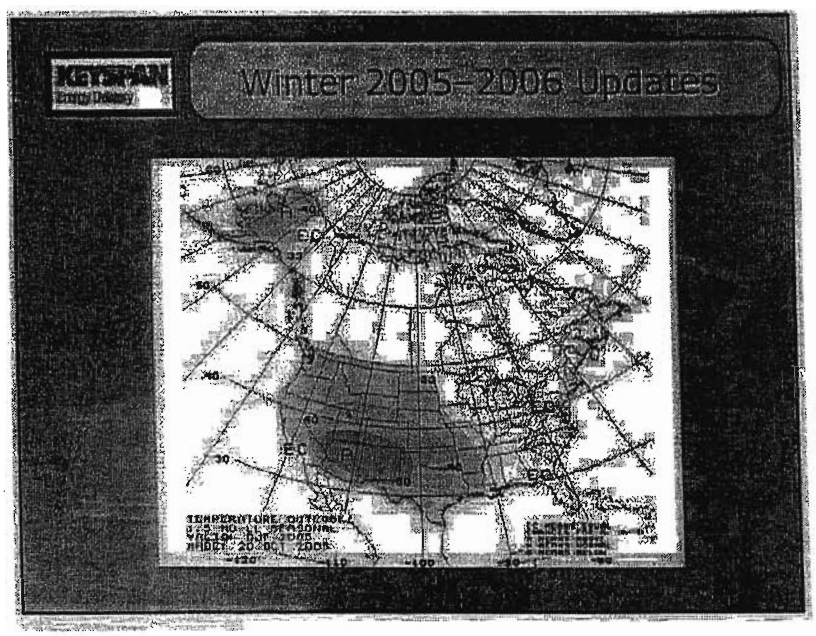
DISTRIGAS CONTRACTS SUMMARY					
Company	Contract	MDQ	ACQ	Vapor	Trucks
ALL	FLS160		4,000,000		X
	FLS129		3,900,000		X
Boston	FVS217	20,600	61,800	X	
	FVS254	30,000	1,000,000	X	
	FVS265	20,000	1,800,000	X	
Colonial	FCS064	16,006	3,335,000	X	X
Essex	FCS027	6,000	906,000	X	X
EnergyNorth	FVS256	8,000	1,208,000	X	
	FLS162		50,050		X

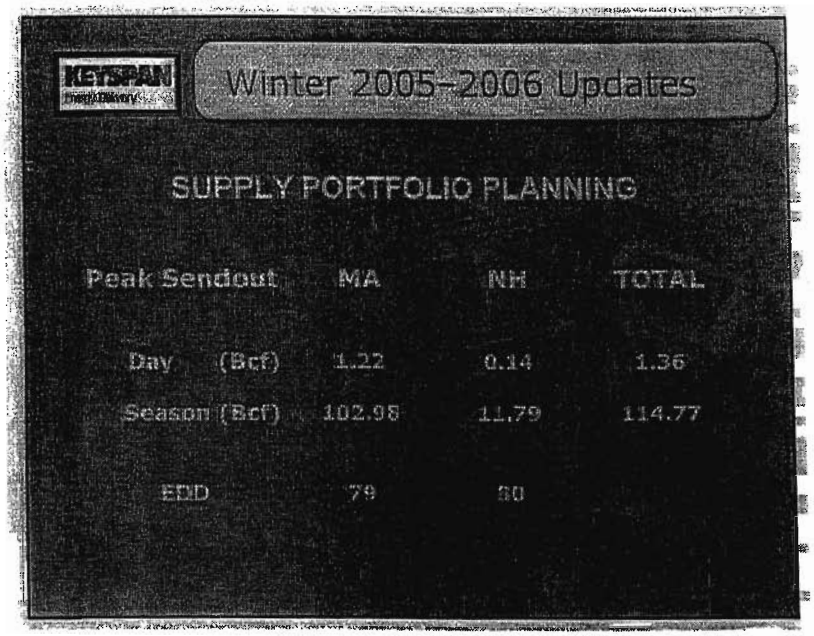
NOTE:
Gas Supply will provide Gas Control with a monthly Distrigas Liquid dispatch order for each Company.
Required to notify Distrigas of monthly FLS election by the 25th of the month

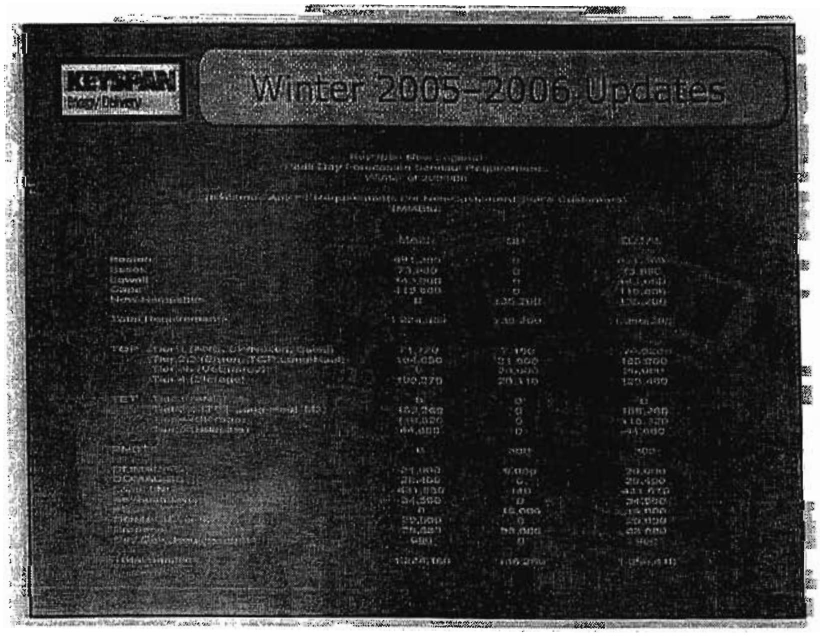
Winter 2005–2006 Updates

SUPPLY PLANNING


KEYSPAN
Energy Delivery
Winter 2005–2006 Updates


KEYSPAN
Energy Delivery
Winter 2005–2006 Updates
TEMPERATURE OUTLOOK


KEYSPAN
Winter 2005-2006 Updates
SUPPLY PORTFOLIO PLANNING
Peak Sendout MA NH TOTAL
Day (Bcf) 1.22 0.14 1.36
Season (Bcf) 102.98 11.79 114.77
EDD 79 80


KEYSPAN
Winter 2005-2006 Updates

KEYSPAN Energy Delivery

Winter 2005-2006 Updates

SUPPLY PORTFOLIO PLANNING

November 1st, 2005 Inventory Status:

- Underground Storage Fields 100 % Full
- On-Site LNG Tanks 100 % Full
- On-Site Propane Tanks 100 % Full

KEYSPAN Energy Delivery

Winter 2005-2006 Updates

HURRICANE UPDATES

KEYSPAN

Winter 2005–2006 Updates

CONTINGENCY PLANNING ACTIVITY

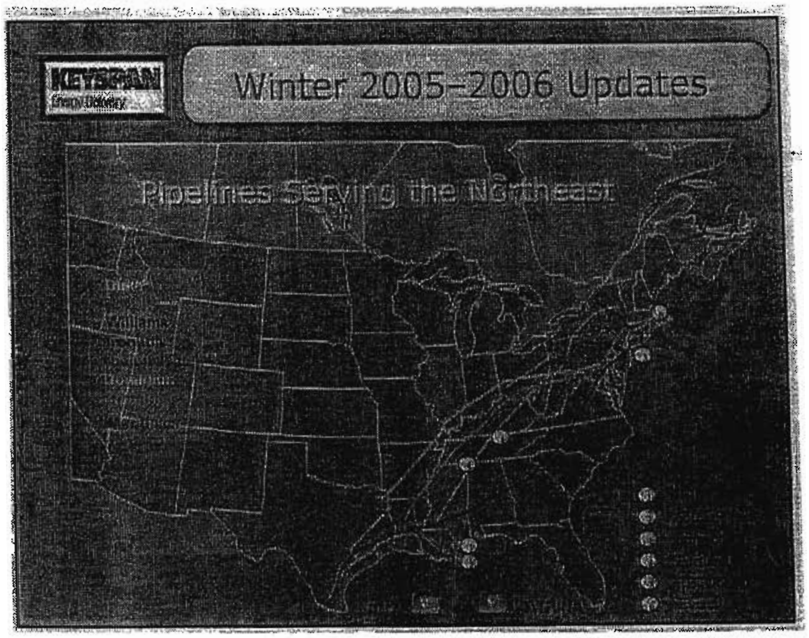
- Purchased volumes upstream of constraint points for November – March period
- Implement plan to "husband" underground and on-system storages
- Continued participation on weekly NGA Gas Supply Task Force conference calls

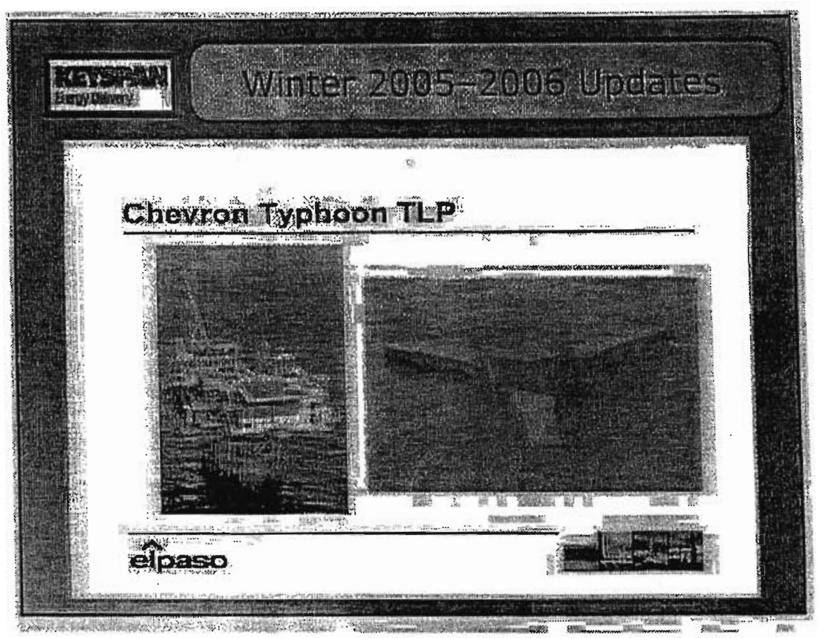
KEYSPAN

Winter 2005–2006 Updates

CONTINGENCY PURCHASES

Volume (MMBTU/Day)	Term	Pipeline	Location
30,000	Nov – Mar	TGP	Gulf South (Kiln)
10,000	Nov – Mar	TGP	500 Leg Pool (onshore)
10,000	Nov – Mar	TGP	Stagecoach
6,600	Nov – Mar	TGP	Portland (Midwestern Interconnect)
4,400	Dec – Mar	TGP	Portland (Midwestern Interconnect)
70,000	Nov – Mar	TETCO	TETCO M1
20,000	Nov – Mar	AGT/TGP	Everett, MA


KEYSPAN
Energy Delivery
Winter 2005–2006 Updates
Pipelines Serving the Northeast


KEYSPAN
Energy Delivery
Winter 2005–2006 Updates
Chevron Typhoon TLP
elpaso

KEYSPAN Energy Delivery

Winter 2005–2006 Updates

NHPUC 7 – DAY REQUIREMENT

- Based on the 20 year coldest 7 day requirement
- Before Oct 1 of each year, provide the 7 day peak shaving requirement to NHPUC.
- Weekly gas storage report from Dec 1 – Apr 1.
- Minimum inventory level
  - 100% Dec 1 - Feb 14
  - 75% Feb 15 - Feb 28
  - 50% Mar 1 - Mar 31
- 70 % of monthly delivery over a 5 day period (MCQ*70%) from a dependable source.
- No rail cars contracted for 2004-2005.

KEYSPAN Energy Delivery

Winter 2005–2006 Updates

ENERGYNORTH UNDERGROUND STORAGE DISPATCH REQUIREMENT

"Rule Curve"

- Used to determine the minimum overall end-of-month inventory level

$$\frac{\text{cumulative forecasted usage under design weather scenario}}{\text{Total MSQ}}$$

- May withdraw volumes to levels below the rule curve as of any given day
- Storage Balance ***must*** remain ***at or above the rule curve*** as of the ***last day of each month***

Winter 2005–2006 Updates

EASTERN PROPANE CONTRACT

- **Contract Period:** December 2005 - February 2006
- **Maximum Monthly Quantity Delivered:**
  - December 2005: 169,000 Gallons
  - January 2006: 470,000 Gallons
  - February 2006: 361,000 Gallons

  Winter Total: 1,000,000 Gallons

- **Maximum 6 trucks a day**
- **Must take contract**

Winter 2005–2006 Updates

TRANSGAS DEDICATED TRUCKING

- **Contractual Language**
  - Provide Transgas with 24hrs notice prior to scheduled trucking. Dispatching on less notice will be done on a best effort basis.
- **Tariff Change**
  - Same Detention Charge and Free Time
    - 2 Hours for loading, and 2 hours for unloading
  - New Diesel Fuel Surcharge

- **Design Day**

  KeySpan has 15 dedicated trucks/ 30 drivers
  - 7 dedicated to Portable Vaporizers:
    - 6 for Colonial: 4 Chatham, 2 Eastham
    - 1 for EnergyNorth: Penacook
  - [illegible] remaining trucks divided among the companies on an as needed basis, [illegible] for Energy North

Winter 2005–2006 Updates

- Additional Portfolio Information
  - Medford OBA – 65,201 MMBtu
  - Whitman Meter 2,000 MMBtu/day
  - Dornac FVS254 replacement for SS-1
  - Last cycle nomination changes (7:30 AM)
    - +/- 10,000 MMBtu on Algonquin and +/- 25,000 MMBtu on Tennessee; Monday through Friday only;
    - All other nomination changes will need to be done for the evening cycle

Winter 2005–2006 Updates

DISTRIGAS CONTRACT (FTS1)

- Allows delivery of volumes from Distrigas tailgate to AGT and TGP citygates
- MDQ – MMBtu/Day:

	AGT	TGP
Nov 16 – Mar 31	40,000	40,000
Apr 1 – Nov 15	25,000	25,000

Winter 2005–2006 Updates

TGP: DAILY IMBALANCE CHARGE

- Encourages customers to remain in balance.
- Assessed on imbalances greater than 10% of scheduled volumes or 1,000 Dth., whichever is greater.
- Penalty = 2 x $0.3695 = $0.7390 Per MMBtu
- TGP: OFO Penalties:

• Action Alert	48 hrs notice; = $0.2196
• Critical Day 1	11 hrs notice; $5 +highest regional spot price
• Critical Day 2	11 hrs notice; $10 +highest regional spot price
• Balancing Alert	8 hrs notice; $15 +highest regional spot price

Winter 2005–2006 Updates

- Weekly Winter Operations Meeting
  - Start: Thursday December 1, 2005
  - Time: 9:30 AM
  - Place: TBD


KEYSPAN
SUMMARY
"
The universe is not required to be in perfect harmony with human ambition.
"
Carl Sagan

Appendix 15

KeySpan New England
Sample
Capacity Release Financial Summary Report

Keyspan Energy
Nov-05

Capacity Assigned - FT cust.
Estimated Reservation Credits by Contract

Printed
1-Dec-05

Company	Pipeline	Contract	Supplier	Volume	Days	Est. Rate	Rate Description	Tariff Sheet	Estimated Amount	Total Credits	Invoice Amt
ENorth	IGTS	47001	Reservation	4,047		6.8514	0	0	$27,727.62		
ENorth	IGTS	47001	Amerada Hess	0		6.8514	0	0	$0.00		
ENorth	IGTS	47001	Direct	0		6.8514	0	0	$0.00		
ENorth	IGTS	47001	Metromedia	(79)		6.8514	0	0	($541.26)		
ENorth	IGTS	47001	Select	(72)		6.8514	0	0	($493.30)		
ENorth	IGTS	47001	Sprague	(23)		6.8514	0	0	($157.58)		
			Broker Total	(174)						($1,192.14)	
ENorth	IGTS	47001	Merrill Lynch	3,873		6.8514	0	0	$26,535.47	$26,535.47	
ENorth	IGTS	47001	Commodity	116,490		0.0054			$629.05		$27,164.52
ENorth	DOMINION	300076	Reservation	934		1.8825	GSS Total St	Sheet No 35	$1,758.26		
ENorth	DOMINION	300076	Amerada Hess	0		1.8825	GSS Total St	Sheet No 35	$0.00		
ENorth	DOMINION	300076	Direct	0		1.8825	GSS Total St	Sheet No 35	$0.00		
ENorth	DOMINION	300076	Metromedia	(16)		1.8825	GSS Total St	Sheet No 35	($30.12)		
ENorth	DOMINION	300076	Select	(15)		1.8825	GSS Total St	Sheet No 35	($28.24)		
ENorth	DOMINION	300076	Sprague	(3)		1.8825	GSS Total St	Sheet No 35	($5.65)		
ENorth	DOMINION	300076		0		1.8825	GSS Total St	Sheet No 35	$0.00		
			Broker Total	(34)						($64.01)	$0.00
ENorth	DOMINION	300076	Merrill Lynch	(900)		1.8825	GSS Total St	Sheet No 35	($1,694.25)	($1,694.25)	$0.00
			Contract Total	934						($1,758.26)	$0.00
ENorth	DOMINION	300076	Reservation	102,700		0.0145	GSS Storage	Sheet No 35	$1,489.15		
ENorth	DOMINION	300076	Amerada Hess	0		0.0145	GSS Storage	Sheet No 35	$0.00		
ENorth	DOMINION	300076	Direct	0		0.0145	GSS Storage	Sheet No 35	$0.00		
ENorth	DOMINION	300076	Metromedia	(1,733)		0.0145	GSS Storage	Sheet No 35	($25.13)		
ENorth	DOMINION	300076	Select	(1,597)		0.0145	GSS Storage	Sheet No 35	($23.16)		
ENorth	DOMINION	300076	Sprague	(378)		0.0145	GSS Storage	Sheet No 35	($5.48)		
ENorth	DOMINION	300076		0		0.0145	GSS Storage	Sheet No 35	$0.00		
			Broker Total	(3,708)						($53.77)	$0.00
ENorth	DOMINION	300076	Merrill Lynch	(98,992)		0.0145	GSS Storage	Sheet No 35	($1,435.38)	($1,435.38)	$0.00
			Contract Total	102,700						($1,489.15)	$0.00
								DOMINION ENorth Total		($3,247.41)	$0.00
ENorth	TGP	11234	Reservation	9,039		5.6822	Z5-Z6 and Z‹	Sheet No. 23	$51,361.41		
ENorth	TGP	11234	Metromedia	(153)		5.6829	Z5-Z6 and Z‹	Sheet No. 23	($869.48)		
ENorth	TGP	11234	Select	(140)		5.6843	Z5-Z6 and Z‹	Sheet No. 23	($795.80)		
ENorth	TGP	11234	Sprague	(33)		5.6864	Z5-Z6 and Z‹	Sheet No. 23	($187.65)		
ENorth	TGP	11234		0			Z5-Z6 and Z‹	Sheet No. 23	$0.00		
ENorth	TGP	11234		0			Z5-Z6 and Z‹	Sheet No. 23	$0.00		
			Broker Totals	(326)						($1,852.94)	($0.54)
ENorth	TGP	11234	Merrill Lynch	(8,713)		5.6821	Z5-Z6 and Z‹	Sheet No. 23	($49,508.14)	($49,508.14)	$0.87
			Contract Totals	9,039						($51,361.07)	$0.33
ENorth	TGP	2302	Reservation	3,122		4.9300	FT-A Z5-Z6	Sheet No. 23	$15,391.46		
ENorth	TGP	2302	Metromedia	(60)		4.9300	FT-A Z5-Z6	Sheet No. 23	($295.80)		
ENorth	TGP	2302	Select	(54)		4.9300	FT-A Z5-Z6	Sheet No. 23	($266.22)		
ENorth	TGP	2302	Sprague	(18)		4.9300	FT-A Z5-Z6	Sheet No. 23	($88.74)		
ENorth	TGP	2302		0		4.9300	FT-A Z5-Z6	Sheet No. 23	$0.00		
ENorth	TGP	2302		0		4.9300	FT-A Z5-Z6	Sheet No. 23	$0.00		
			Broker Totals	(132)						($650.76)	$0.00
ENorth	TGP	2302	Merrill Lynch	0		4.9300	FT-A Z5-Z6	Sheet No. 23	$0.00	$0.00	$0.00
ENorth	TGP	2302	Commodity (Mkt)	*0*		0.0784	FT-A Z5-Z6	Sheet No. 23	$0.00		
ENorth	TGP	2302	Commodity	*89,700*		0.0784	FT-A Z5-Z6	Sheet No. 23	$7,032.48		
			Contract Total	(89,568)						($650.76)	$21,773.18

ENorth	TGP	33371	Reservation	4,000		10.6100	NET 284 Sec	Sheet No. 26	$42,440.00		
ENorth	TGP	33371	Metromedia	(78)		10.6100	NET 284 Sec	Sheet No. 26	($827.58)		
ENorth	TGP	33371	Select	(71)		10.6100	NET 284 Sec	Sheet No. 26	($753.31)		
ENorth	TGP	33371	Sprague	(23)		10.6100	NET 284 Sec	Sheet No. 26	($244.03)		
ENorth	TGP	33371		0		10.6100	NET 284 Sec	Sheet No. 26	$0.00		
ENorth	TGP	33371		0		10.6100	NET 284 Sec	Sheet No. 26	$0.00		
			Broker Total	**(172)**						**($1,824.92)**	**$0.00**
ENorth	TGP	33371	Merrill Lynch	0		10.6100	NET 284 Sec	Sheet No. 26	$0.00	**$0.00**	**$0.00**
ENorth	TGP	33371	Commodity	*114,840*	30	0.0019	NET 284 Sec	Sheet No. 26	$218.20		
			Contract Total	**4,000**						**($1,824.92)**	**$40,833.28**
ENorth	TGP	632	Reservation	15,265		5.8900	FT-A Z4-Z6	Sheet No. 23	$89,910.85		
ENorth	TGP	632	Metromedia	(258)		5.8900	FT-A Z4-Z6	Sheet No. 23	($1,519.62)		
ENorth	TGP	632	Select	(237)		5.8900	FT-A Z4-Z6	Sheet No. 23	($1,395.93)		
ENorth	TGP	632	Sprague	(56)		5.8900	FT-A Z4-Z6	Sheet No. 23	($329.84)		
ENorth	TGP	632		0		5.8900	FT-A Z4-Z6	Sheet No. 23	$0.00		
ENorth	TGP	632		0		5.8900	FT-A Z4-Z6	Sheet No. 23	$0.00		
			Broker Total	**(551)**						**($3,245.39)**	**$0.00**
ENorth	TGP	632	Merrill Lynch	(14,714)		5.8900	FT-A Z4-Z6	Sheet No. 23	($86,665.46)	**($86,665.46)**	**$0.00**
			Contract Total	**15,265**						**($89,910.85)**	**$0.00**
ENorth	TGP	8587	Reservation	25,407		14.1597	Z4-Z6, Z0-Z6	Sheet No. 23	$359,755.50		
ENorth	TGP	8587	Metromedia	(486)		14.3365	Z4-Z6, Z0-Z6	Sheet No. 23	($6,967.54)		
ENorth	TGP	8587	Select	(442)		14.3179	Z4-Z6, Z0-Z6	Sheet No. 23	($6,328.51)		
ENorth	TGP	8587	Sprague	(139)		24.2292	Z4-Z6, Z0-Z6	Sheet No. 23	($3,367.86)		
ENorth	TGP	8587		0			Z4-Z6, Z0-Z6	Sheet No. 23	$0.00		
ENorth	TGP	8587		0			Z4-Z6, Z0-Z6	Sheet No. 23	$0.00		
			Broker Totals	**(1,067)**						**($16,663.91)**	**($1,555.51)**
ENorth	TGP	8587	Merrill Lynch	(24,340)		14.1506	Z4-Z6, Z0-Z6	Sheet No. 23	($344,425.60)	**($344,425.60)**	**$221.49**
			Contract Total	**25,407**						**($361,089.51)**	**($1,334.02)**
ENorth	TGP	2122	Reservation	0		16.9600	CGT-NE Der	Sheet No. 21	$0.00		
ENorth	TGP	2122	Commodity (Mkt)	*0*		0.0035	CGT-NE Cor	Sheet No. 21	$0.00		
ENorth	TGP	2122	Commodity (ML)	*0*		0.0035	CGT-NE Cor	Sheet No. 21	$0.00		
			Contract Total	**0**						**$0.00**	**$0.00**
ENorth	TGP	523	Reservation	21,844		1.1500	FS-MA Deliv	Sheet No. 27	$25,120.60		
ENorth	TGP	523	Reservation	1,560,391		0.0185	FS-MA Spac	Sheet No. 27	$28,867.23		
ENorth	TGP	523	Metromedia	(369)		1.1500	FS-MA Deliv	Sheet No. 27	($424.35)		
ENorth	TGP	523	Metromedia	(26,337)		0.0185	FS-MA Spac	Sheet No. 27	($487.23)		
ENorth	TGP	523	Select	(340)		1.1500	FS-MA Deliv	Sheet No. 27	($391.00)		
ENorth	TGP	523	Select	(24,271)		0.0185	FS-MA Spac	Sheet No. 27	($449.01)		
ENorth	TGP	523	Sprague	(80)		1.1500	FS-MA Deliv	Sheet No. 27	($92.00)		
ENorth	TGP	523	Sprague	(5,748)		0.0185	FS-MA Spac	Sheet No. 27	($106.34)		
ENorth	TGP	523		0		1.1500	FS-MA Deliv	Sheet No. 27	$0.00		
ENorth	TGP	523		0		0.0185	FS-MA Spac	Sheet No. 27	$0.00		
ENorth	TGP	523		0		1.1500	FS-MA Deliv	Sheet No. 27	$0.00		
ENorth	TGP	523		0		0.0185	FS-MA Spac	Sheet No. 27	$0.00		
			Broker Total	**(789)**							
			Broker Total	**(56,356)**						**($1,949.94)**	**$0.00**
ENorth	TGP	523	Merrill Lynch	(21,055)		1.1500	FS-MA Deliv	Sheet No. 27	($24,213.25)		
ENorth	TGP	523	Merrill Lynch	(1,504,035)		0.0185	FS-MA Spac	Sheet No. 27	($27,824.65)	**($52,037.90)**	**$0.00**
			Contract Total	**21,844**						**($53,987.83)**	**$0.00**
				1,560,391							
ENorth	TGP	42076	Reservation	20,000		3.1600	FT-A Z6-6	Sheet No. 23	$63,200.00		
ENorth	TGP	42076	Metromedia	(391)		3.1600	FT-A Z6-6	Sheet No. 23	($1,235.56)		
ENorth	TGP	42076	Select	(356)		3.1600	FT-A Z6-6	Sheet No. 23	($1,124.96)		
ENorth	TGP	42076	Sprague	(116)		3.1600	FT-A Z6-6	Sheet No. 23	($366.56)		
ENorth	TGP	42076		0		3.1600	FT-A Z6-6	Sheet No. 23	$0.00		
ENorth	TGP	42076		0		3.1600	FT-A Z6-6	Sheet No. 23	$0.00		
			Broker Total	**(863)**						**($2,727.08)**	**$0.00**
ENorth	TGP	42076	Merrill Lynch	(19,137)		3.1600	FT-A Z6-6	Sheet No. 23	($60,472.92)	**($60,472.92)**	**$0.00**
			Contract Total	**20,000**						**($63,200.00)**	**$0.00**
									TGP ENorth Total	**($622,024.95)**	**$61,272.77**
									BROKER TCTGP ENorth	**($28,914.93)**	**($1,556.05)**

ENorth	Natl. Fuel	N02358	Reservation	6,098	0.0832	Discounted F	N/A	$507.35		
ENorth	Natl. Fuel	N02358	Metromedia	(103)	0.0832	Discounted F	N/A	($8.57)		
ENorth	Natl. Fuel	N02358	Select	(95)	0.0832	Discounted F	N/A	($7.90)		
ENorth	Natl. Fuel	N02358	Sprague	(22)	0.0832	Discounted F	N/A	($1.83)		
ENorth	Natl. Fuel	N02358		0	0.0832	Discounted F	N/A	$0.00		
ENorth	Natl. Fuel	N02358		0	0.0832	Discounted F	N/A	$0.00		
			Broker Totals	(220)					($18.30)	$0.00
ENorth	Natl. Fuel	N02358	Merrill Lynch	(5,878)	0.0832	Discounted F	N/A	($489.05)	($489.05)	$0.00
			Contract Total	6,098					($507.35)	$0.00
ENorth	Natl. Fuel	O02357	Reservation	6,098	2.1556	FSS Max De	Sheet No. 10	$13,144.85		
ENorth	Natl. Fuel	O02357	Capacity Rate	670,800	0.0432	FSS Max Ca	Sheet No. 10	$28,978.56		
ENorth	Natl. Fuel	O02357	Metromedia	(103)	2.1556	FSS Max De	Sheet No. 10	($222.03)		
ENorth	Natl. Fuel	O02357	Metromedia	(11,322)	0.0432	FSS Max Ca	Sheet No. 10	($489.11)		
ENorth	Natl. Fuel	O02357	Select	(95)	2.1556	FSS Max De	Sheet No. 10	($204.78)		
ENorth	Natl. Fuel	O02357	Select	(10,434)	0.0432	FSS Max Ca	Sheet No. 10	($450.75)		
ENorth	Natl. Fuel	O02357	Sprague	(22)	2.1556	FSS Max De	Sheet No. 10	($47.42)		
ENorth	Natl. Fuel	O02357	Sprague	(2,471)	0.0432	FSS Max Ca	Sheet No. 10	($106.75)		
ENorth	Natl. Fuel	O02357		0	2.1556	FSS Max De	Sheet No. 10	$0.00		
ENorth	Natl. Fuel	O02357		0	0.0432	FSS Max Ca	Sheet No. 10	$0.00		
ENorth	Natl. Fuel	O02357		0	2.1556	FSS Max De	Sheet No. 10	$0.00		
ENorth	Natl. Fuel	O02357		0	0.0432	FSS Max Ca	Sheet No. 10	$0.00		
			Broker Totals	(220)						
			Broker Totals	(24,227)					($1,520.84)	$0.00
ENorth	Natl. Fuel	O02357	Merrill Lynch	(5,878)	2.1556	FSS Max De	Sheet No. 10	($12,670.62)		
ENorth	Natl. Fuel	O02357	Merrill Lynch	(646,573)	0.0432	FSS Max Ca	Sheet No. 10	($27,931.95)	($40,602.57)	$0.00
			Contract Total	6,098					($42,123.41)	$0.00
			Contract Total	670,800						
							Total ENorth NATIONAL		($42,630.76)	$0.00
							BROKER TC NATIONAL Enc		($1,539.14)	$0.00
ENorth	PNGTS	FT-1999-01	Reservation	1,000	25.8542	FT Max Reservation		$25,854.20		
ENorth	PNGTS	FT-1999-01	Merrill Lynch	(1,000)	25.8542			($25,854.20)		$0.00