National Grid

The Narragansett Electric Company

Gas Long-Range Resource and Requirements Plan For the Forecast Period 2013/14 to 2022/23

March 10, 2014

Docket No. ______

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

nationalgrid

Filing Letter

nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

March 10, 2014

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Long-Range Gas Supply Plan
Forecast Period 2013/14 to 2022/23
Docket No. _______

Dear Ms. Massaro:

Enclosed are ten (10) copies of National Grid's[1] recently completed Long-Range Gas Supply Plan for the forecast period 2013/14 to 2022/23. During the most recent Gas Cost Recovery proceeding, the Company committed to undertake and submit a new supply plan. The Company has engaged in discussions with the Division's consultant as it worked to produce the enclosed plan.

Thank you for your attention to this transmittal. If you have any questions, please contact me at (401) 784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Steve Scialabba, Division
Leo Wold, Esq.

[1] The Narragansett Electric Company d/b/a National Grid ("the Company").

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Section I
Introduction

I. Introduction

This filing presents the Long-Range Resource and Requirements Plan ("Supply Plan") for The Narragansett Electric Company d/b/a National Grid (the "Company"), for the forecast period November 1, 2013 through October 31, 2023. The Company is submitting this Supply Plan to the Rhode Island Public Utilities Commission (the "PUC") pursuant to Rhode Island General Laws § 39-24-2. The Company is a public utility under the provisions of R.I.G.L. § 39-1-2 and provides natural gas sales and transportation service to approximately 250,000 residential and commercial customers in 32 cities and towns.

This Supply Plan is designed to demonstrate that the Company's gas-resource planning process has resulted in a reliable resource portfolio to meet the combined forecasted needs of the Company's Rhode Island customers at least-cost. To make this demonstration, the Supply Plan presented herein includes: (i) a step-by-step description of the methodology the Company uses to forecast demand on its system; (ii) a discussion of how the Company develops its resource portfolio to meet customer requirements under design-weather conditions; and (iii) 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.

Although the statute only requires a five-year forecast period, the Company has expanded the instant Supply Plan to include a ten-year forecast period in order to encompass the period over which the Company must consider the need to enter into long-term arrangements in order to continue to provide a least-cost, reliable portfolio.

In addition to including the assumptions and methodologies that the Company used in formulating this Supply Plan, the Company has also included additional information requested by the Division of Public Utilities and Carriers' consultant regarding historical weather for the month of January 2014, changes in forecasted volume since the Company's 2012 Supply Plan filing, and pricing dynamics for the 2013/2014 season. The Company has concluded in this instant Supply Plan that given the current supply/demand situation in the New England market, the Company anticipates the need to contract for incremental pipeline capacity as well as long-term liquid natural gas ("LNG") supply services.

Section II
Planning Results
Overview

II. Overview of Planning Results

As described in detail in this filing, the Company's planning process is based on a comprehensive methodology for forecasting customer load requirements using a series of econometric models to determine the annual growth expected for residential heating, residential non-heating and commercial and industrial markets for both sales and transportation services. To determine the projected growth over the forecast period, the econometric models use historical economic, demographic, and energy price data, as well as weather data to determine total energy demand. The Company then analyzed load reductions expected to be achieved through the implementation of its revised energy-efficiency programs, because these reductions are exogenous to the demand forecast generated by the econometric models.

The results of the Company's demand forecast (See Chart III-B-3) indicates that, over the ten-year forecast period, the residential heating market is projected to decrease by an average of 22 BBtu per year, the residential non-heat market is projected to increase by an average of 12 BBtu per year and the commercial and industrial market is projected to grow by 70 BBtu per year. The Company projects that growth opportunities in non-traditional markets over the forecast period are reflected in the results of the econometric models. The Company is not projecting any incremental growth in these markets beyond what it experienced in the historical period upon which these models are based.

As explained below, the Company's demand forecast is then converted to supply requirements at the Company's citygates. The end result of the forecasting process is that projected sendout requirements increase over the forecast period averaging 53 BBtu (approximately 0.2 %) per year under normal weather conditions (See Section III.D.2).

To ensure that the Company maintains adequate supplies in its portfolio to meet the projected customer load requirements, the next step in the planning process involves an analysis to define the planning standards for the coldest planning year, known as the "design year" and the coldest planning day, known as the "design day". The results of the analysis support the Company's determination to define a design year at 6,168 heating degree day ("HDD") with a probability of occurrence of 1 in 43.76 years and a design day at 68 HDD with a probability of occurrence of 1 in 109 years. Combining the results of the design planning standards definition and the load forecasting process, the Company is projecting design-year sendout requirements to increase over the forecast period by an average of 62 BBtu, or approximately 0.2 % per year, and design day sendout to increase by an average of 0.9 BBtu, or 0.3 %, per year (See Section III.F).

After the forecast of customer requirements are determined, the third step in the Company's planning process is to design a resource portfolio to meet those requirements in the most reliable and least-cost manner possible. To that end, the Company uses the SENDOUT® Model (a proprietary linear programming model developed by Ventyx) 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. To evaluate the flexibility and adequacy of the resource portfolio under a range of reasonably foreseeable conditions, the portfolio is assessed under design and normal weather conditions as well as a cold snap weather scenario. The Company's resource plan is sufficient to meet design-year load requirements throughout the forecast period with the addition of incremental capacity or citygate purchases.

For the cold-snap weather scenario, the Company used a 14-day cold snap occurring in the coldest 14-day period of the Company's normal year (15 January - 28 January) by evaluating January weather data from 1972 – 2013. The Company uses the results of the cold snap scenario to test the adequacy of inventories and refill requirements. The Company's resource plan shows that it has adequate resources available to meet cold-snap sendout requirements in all years of the forecast, with the addition of incremental capacity or citygate purchases.

Please note that communications regarding this Supply Plan should be directed as follows:

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As discussed briefly above, this document is organized into the following principal sections:

- Section III reviews the Company's econometric 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 customer requirements under design weather conditions;
- Section V contains a discussion of operational issues the Company would like to address and the Company’s recommendations; and,
- Section VI contains the supporting tables for the filing.
- Appendix A contains additional weather and sendout information, changes in forecasted volume since the Company’s 2012 Supply Plan filing, and pricing dynamics for the 2013/2014 season.

The analysis presented in these sections demonstrates that the Company's planning process results in a reliable resource portfolio that is adequate to meet the forecasted needs of its customers at least-cost with the addition of incremental pipeline capacity as well as long-term LNG supply services.

Section III
Forecast
Methodology

III. Forecast Methodology

III.A. Introduction

The Company's forecast methodology supports its supply planning goal to ensure that it maintains sufficient supply deliverability in its resource portfolio to meet customers' requirements on the design day and that it maintains sufficient supply under contract and in storage (underground storage and LNG) to meet customers' requirements over the design year. Each year, the Company employs the same process of preparing a multi-year forecast in order to ensure that the portfolio has sufficient resources for the upcoming winter period, as well as sufficient time to contract for additional resources should they be required. Specifically, the term "customer" as used herein means those customers for whom the Company must make capacity planning decisions[1].

The Company develops its underlying demand forecast from econometric models of its customer billing data. This data is available by month and by rate class. The Company models its daily resources and requirements with its SENDOUT® linear programming software modeling package, and hence, it needs as input a forecast of daily customer requirements.

Accordingly, the Company developed its ten-year forecast of customer requirements under design-weather planning conditions using the following process:

1. <u>Forecast Retail Demand Requirements</u>

   Retail demand requirements are based on customer billing data, which is available by rate class and by month. The Company uses a series of econometric models to develop a forecast of retail demand requirements for traditional markets (i.e., residential heating, residential non-heating, and commercial and industrial ("C&I") customers). The forecast of retail demand requirements for traditional markets is summed to determine the total retail demand requirements over the forecast period. This forecast of retail demand is disaggregated into monthly billed and unbilled volumes and, hence, can be calendarized for supply planning purposes.

2. <u>Develop Reference Year Sendout Using Regression Equations</u>

   The daily values of the Company's wholesale sendout in the reference year (April 2012 – March 2013) serves as the basis of allocating the monthly retail demand forecast to the daily level. Because actual sendout data for the reference year is a function of the weather conditions experienced in that year, the Company develops this allocator for sendout using regression equations to normalize the sendout in the reference year based on normalized weather data.

[1] The Company makes capacity planning decisions for its sales and non-grandfathered transportation ("Customer Choice") customers.

3. Normalize Forecast of Customer Requirements

   The Company's monthly retail demand forecast is allocated to the daily level based on the use of its daily wholesale sendout regression equation and its normal daily heating degree day data. This step sets the Company's total normalized forecast of customer requirements over the ten-year forecast period.

4. Determine Design Weather Planning Standards

   The Company performs an 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.

5. Determine Customer Requirements Under Design Weather Conditions

   Using the applicable design day and design year weather planning standards, the Company determines the design year sendout requirements and the design day sendout requirements. These design sendout requirements establish the Company's resource requirements over the forecast period.

To test the sensitivity of the resource portfolio to variations away from the Company's base case forecasted customer requirements, the Company developed a high-case customer requirements scenario. The high-case scenario was based on an additional one percent growth per annum above the annual base-case-growth rate. Because of the flat-base-case customer requirements projections, the Company chose not to run a low-case customer requirements forecast for this filing.

Based on the forecast, the Company projects base-case growth in customer requirements of 474 BBtus over the forecast period or 53 BBtus per year (assuming normal weather) (See Section III.D.2). Overall, this growth in firm sales represents a 1.4 percent total increase in sendout requirements over the forecast period, or 0.2 percent per year on average.

Based on the forecast, the Company projects high-case growth in customer requirements of 3,651 BBtus over the forecast period or 406 BBtus per year (assuming normal weather) (See Section III.D.2). Overall, this growth in firm sales represents a 10.9 percent total increase in sendout requirements over the forecast period, or 1.2 percent per year on average.

The development of the Company's ten-year forecast of customer sendout requirements, based on the steps set forth above, is described in the following sections.

III.B. Forecast of Retail Demand ("Demand Forecast")

III.B.1 Introduction

The first step in the Company's forecasting methodology is the generation of its retail demand forecast, which is prepared through econometric and statistical modeling.

III.B.2 Demand Forecast for Traditional Markets

III.B.2.a Service Territory Specific Data Availability

The Company used its monthly customer billing data (volume and number of customers) for the period July 2005 through February 2013 to define the dependent variables in its econometric models. The billing data was modeled at the rate class level for the various classes of customers (residential heat, residential non-heat, commercial and industrial heat, commercial and industrial non-heat, etc.). Additionally, the data was also divided into the sales customer classes, the Customer Choice customer classes, and the "zero-capacity" (i.e. grandfathered transportation) customer classes.

With the conversion of the Company's customer billing system, the Company uses new rate codes for each class. A chart listing the new and old rate code categories is provided as Chart III-B-1. Specifically, the table below lists the relevant customer classes and rate classes used in the Company's analysis.

	Sales	Customer Choice	Zero-Capacity
Residential Heating	400, 402		
Residential Non-Heating	401, 403		
Commercial/Industrial Heating	404, 405, 408, 409, 412, 413, 416, 444	406, 407, 410, 411, 414, 415, 443	Z407, Z411, Z415
Commercial/Industrial Non-Heating	417, 420, 421, 424	418, 419, 422, 423	Z419, Z423
Non-Firm	433, 435, 437, 439, 441	434, 436, 438, 440, 442	

III.B.2.b Econometric Models

With volume and customer data as identified above, the Company developed econometric models for the number of customers and use per customer (the quotient of the division of volume and number of customers) for each class. The Company's econometric modeling effort was to regress each of the two dependent variables against an array of possible independent variables and select the equation with the best fit.

By using historical economic, demographic and energy price data, listed in Chart III-B-2, as the independent variables, the Company estimated statistically valid econometric equations for each class. The Company obtained the economic and demographic data from Moody's economy.com the forecasts for which were from February 2013.

Additionally, the Company tested date as a time trend variable, actual Heating Degree Days, actual Billing Degree Days, as well as natural gas and oil prices from the Department Of Energy/Energy Information Administration ("DOE/EIA").

The Company then reduced the results of its statistical forecast models to account for the incremental impact of the energy efficiency programs sponsored by the Company. The energy-efficiency programs that the Company analyzed for this forecast were those submitted by the Company in Docket No. 4451 in its supplemental gas filing dated November 26, 2013, the most recent data available at the time the forecast was prepared. The Company subtracted the incremental savings from the programs that are not embedded in the historical data used to derive the statistical models, because these savings are exogenous to the modeling effort.

III.B.3 Final econometric models for the Company's demand forecast

III.B.3.a Residential Heating Class

The residential heating class represents approximately 54 percent of the Company's total firm sendout to Sales and Customer Choice customers. The Company prepared the demand forecast for the residential heating class by developing separate econometric models for numbers of customers and use per customer. There is a separate model for each residential heating class (rate codes 400 and 402). The Company multiplied the results of the econometric number of customer equations by the results of the corresponding econometric use per customer equations to calculate total sales in Dth. Finally, it applied the estimated impact of the Company-sponsored energy-efficiency programs to derive the annual net sales volumes.

Residential heating deliveries are forecast to decrease by an average of 22 BBtu per year or -0.1% per year over the forecast period, 2013/14 through 2022/23, driven by a decrease in the average use per customer. The forecast results for the residential heating class are presented in Chart III-B-3.

The net residential heating customer count is forecast to increase by an average of 49 per year or 0.0% per year over the forecast period, 2013/14 through 2022/23. The forecast results for the residential heating customers are presented in Chart III-B-4. Annual customer counts for the residential heating class were modeled as a function of time trends and gas price. The monthly variation in customer counts was modeled using logistic functions that capture the seasonal decline in customer counts that occurs during the summer months and the subsequent increase during the winter months.

Residential heating use per customer is forecast to decrease by an average of 0.1 Dth/customer per year or -0.2% per year over the forecast period, 2013/14 through 2022/23. The forecast results for the residential heating class use per customer are presented in Chart III-B-5. Use-per-customer for the residential heating class was modeled as a function of degree days, employment, and time trends.

The results of the customer count forecasts and the use-per-customer forecasts were then multiplied together to derive the volume delivery forecast presented in Chart III-B-3.

III.B.3.b Residential Non-Heating Class

The residential non-heating class represents approximately 2 percent of the Company's total firm sendout to Sales and Customer Choice customers. The Company prepared the demand forecast for the residential non-heating class by developing separate econometric models for numbers of customers and use per customer. There is a separate model for each residential non-heating class (rate codes 401 and 403). The Company multiplied the results of the econometric equations for the number of customers by the results of the corresponding econometric equations for use per customer to calculate total sales. Lastly, it reduced the results of its statistical forecast models to account for the incremental impact of the energy efficiency programs sponsored by the Company.

Residential non-heating deliveries are forecast to increase by an average of 12 BBtu per year, or 1.7%, per year over the forecast period 2013/14 through 2022/23, due to a slight upward trend in the use per customer. The forecast volumes for the residential non heating class are presented in Chart III-B-3.

The net residential non-heating customer count is forecast to increase by an average of 8 per year, or 0.0%, per year over the forecast period 2013/14 through 2022/23. The forecast results for the residential non-heating customers are presented in Chart III-B-4. Annual customer counts for the residential non-heating class were modeled as a function of time trends. The monthly variation in customer counts was modeled using logistic functions that capture the seasonal decline in customer counts that occurs during the summer months and the subsequent increase during the winter months.

Residential non-heating use per customer is forecast to increase by an average of 0.5 Dth/customer per year, or 1.6%, per year over the forecast period 2013/14 through 2022/23. The forecast results for the residential heating use per customer are presented in Chart III-B-5. Use-per-customer for the residential non-heating class was modeled as a function of degree days, personal disposable income and time trends.

The results of the customer count forecasts and the use-per-customer forecasts were then multiplied together to derive the volume delivery forecast presented in Chart III-B-3.

III.B.3.c Commercial/Industrial Heating Class

The commercial and industrial heating class represents approximately 36 percent of the Company's total firm sendout to Sales and Customer Choice customers. The Company prepared the demand forecast for the commercial and industrial heating class by developing separate econometric models for numbers of customers and use per customer. The Company multiplied the results of the econometric equations for number of customer by the results of the corresponding econometric equations for use per customer to calculate total sales. Lastly, it reduced the results of its statistical forecast models to account for the incremental impact of the energy efficiency programs sponsored by the Company.

There are separate models for the commercial and industrial heating classes (Sales: 404, 405, 408, 409, 412, 413, 416; Customer Choice: 406, 407, 410, 411, 414, 415, 443; Zero Capacity: Z407, Z411, Z415).

The Commercial and industrial heating class demand is forecast to increase by an average of 84 BBtu per year or 1.2% per year over the forecast period 2013/14 through 2022/23, driven by an increase in both customer count and use-per-customer. The forecast volumes for the commercial and industrial heating class are presented in Chart III-B-3.

The net commercial and industrial heating class customer count is forecast to increase by an average of 98 per year, or 0.4%, per year over the forecast period 2013/14 through 2022/23. The forecast results for the commercial and industrial heating class customers are presented in Chart III-B-4. The customer counts for the commercial and industrial heating class were modeled as a function of time trends.

The Commercial and industrial heating class use per customer is forecast to increase by an average of 1.5 Dth/customer per year, or 0.3% per year, over the forecast period 2013/14 through 2022/23. The forecast results for the commercial and industrial heating class use per customer are presented in Chart III-B-5. The Use-per-customer for the commercial and industrial heating class was modeled as two components. The first component captures base load, or non-heating load, per customer; the second component captures the heating load per customer. The base load use-per-customer models for the commercial and industrial heating class were developed on annual data as a function of population, household income, housing sales prices, housing stock, time trends and gas price. The heating load component of the model captures the long-term trend in use per customer and the seasonal fluctuation of gas demand for this class. The Company modeled the annual trend in heating loads as a function of employment rate, housing stock, personal income, population, natural gas prices and time trends. It should be noted that except for time trends, the same variables were not used for the base load and heating load models for a specific class. The Company first modeled monthly heating load use-per-customer as a function of heating degree days. Then, in order to capture the non-linear nature of the relationship between monthly use-per-customer and heating degree days, the Company calculated "alpha factors" that are modeled as the ratio of the fitted values of the regression equations to the actual values to correct for the linear nature of regressions.

The results of the customer count forecasts and the use-per-customer forecasts were then multiplied together to derive the volume delivery forecast presented in Chart III-B-3.

III.B.3.d Commercial/Industrial Non-Heating Class

The commercial and industrial non-heating class represents approximately 8 percent of the Company's total firm sendout to Sales and Customer Choice customers. The Company first prepared the demand forecast for the commercial and industrial non-heating class by developing separate econometric models for numbers of customers and use per customer. The Company then multiplied the results of the econometric equations for number of customer by the results of the corresponding econometric equations for use per customer to calculate total sales. Lastly, the Company reduced the results of its statistical forecast models to account for the incremental impact of the energy efficiency programs sponsored by the Company.

There are separate models for the commercial and industrial non-heating classes (Sales: 417, 420, 421, 424; Customer Choice: 418, 419, 422, 423; Zero Capacity: Z419, Z423).

The Commercial and industrial non-heating class demand is forecast to decrease by an average of 14 BBtu per year or -0.5% per year over the forecast period 2013/14 through 2022/23, driven by a decrease in use per customer. The forecast volumes for the commercial and industrial non-heating class are presented in Chart III-B-3.

The net commercial and industrial non-heating class customer count is forecast to increase by an average of 0 per year, or -0.1%, per year over the forecast period 2013/14 through 2022/23. The forecast results for the commercial and industrial non-heating class customers are presented in Chart III-B-4. Customer counts for the commercial and industrial non-heating classes were modeled as a function of time trends.

The Commercial and industrial non-heating class use, per customer, is forecast to increase by an average of -52.7 Dth/customer per year, or -0.4% per year, over the forecast period 2013/14 through 2022/23. The forecast results for the commercial and industrial non-heating class use per customer are presented in Chart III-B-5. Use-per-customer for the Commercial/Industrial Non Heating classes was modeled as a single component. Use-per-customer was modeled on annual data as a function of population, disposable personal income, employment, housing stock, gas price, and time trends. Then the Company developed an algorithm to determine the relationship between monthly consumption and heating degree days for this class to allocate the forecasted annual use per customer to monthly use per customer.

The results of the customer count forecasts and the use-per-customer forecasts were then multiplied together to derive the volume delivery forecast presented in Chart III-B-3.

III.B.3.e Commercial and Industrial Dual-Fuel Customers

Since fuel switching between natural gas and alternate fuel(s) can decrease the accuracy of econometric forecasting equations, the monthly billing volumes for the Company's dual-fuel customers were subtracted from its rate class billing data prior to development of the individual rate class forecasts. After the forecast was set, the dual-fuel volumes were added back in, both historically and into the forecast period, assuming no change in historical consumption levels.

III.B.4.The Impact of the Energy Efficiency Programs

On November 1, 2013, the Company filed its 2014 Energy Efficiency Program Plan (the 2014 "EE Program Plan") in Docket No. 4451, which was approved by the PUC on December 20, 2014. The primary goal of the 2014 EE Program Plan is to create energy (both gas and electric) and economic cost savings for Rhode Island consumers as required by the least cost procurement law, R.I.G.L. § 39-1-27.7. The goal of the natural gas energy-efficiency programs is annual reduction in usage; there are no programs that are specifically targeted toward peak reduction.

Since the Company's econometric forecast is based on historical data which does not fully incorporate the increasing penetration of the Company's energy efficiency programs in the residential and commercial and industrial sectors, the Company reviewed its historical energy-efficiency efforts and adjusted its retail demand forecast (downward) to reflect the increases in energy-efficiency efforts.

In the Company's November 26, 2013 supplemental gas filing in Docket No. 4451, Table G-7 (Attachment 5 – Revised) reflects approved 2013 energy-efficiency programs of 116,973 MMBtu for residential and 170,802 MMBtu for commercial and industrial. Additionally, the Company proposed 2014 savings of 160,500 MMBtu for residential and 169,463 MMBtu for commercial and industrial.

Analysis of the Company's historical energy efficiency programs shows that historical data should have embedded within it savings of 75,332 MMBtu for residential and 105,262 MMBtu for commercial and industrial. Therefore, the Company reduced its demand forecast by the incremental savings over the historical average. For 2013, the Company's demand forecast was reduced by 41,641 MMBtu for residential and 65,540 MMBtu for commercial and industrial. For 2014 and beyond, the Company's demand forecast was reduced annually by 85,168 MMBtu for residential and 64,201 MMBtu for commercial and industrial.

III.C. Translation of Customer Demand into Customer Requirements

III.C.1 Regression Equation

In the second step of the Company's forecasting methodology, the Company uses linear regression equations of total daily sendout versus daily temperature for the most recent twelve months to calculate a reference-year by division. This serves as the most accurate way for the Company to allocate its monthly demand forecast into its future daily customer requirements. This step is used to determine the Company's normal year forecast of customer requirements over the forecast period for gas cost recovery purposes, and to determine the Company design year forecast of customer requirements over the forecast period for resource planning purposes. To perform its regression analysis, the Company used version 2.15.1 of the "R" statistical software package[2].

To establish normal-year springboard sendout requirements, the Company developed a linear-regression equation for each of its four divisions (Providence, Westerly, Bristol & Warren Gas, and Valley Gas) using data for the reference-year period April 1, 2012 through March 31, 2013. Its regression equation uses sendout as its dependent variable and temperature as its independent variable[3].

Through the use of the linear-regression equation, the Company is able to normalize total daily sendout. Specifically, the actual daily firm sendout is regressed against heating degree day ("HDD") data as provided by its weather service vendor WSI, HDD data lagged over two days, 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 the Company's daily sendout requirements.

The Company selected the T.F. Green International Airport weather station ("KPVD") as the source of the weather data that is used as the principal explanatory variable in its regression equations. The KPVD weather station was selected because it is close to the center of the Company's service territory, on a load-weighted basis, and it is highly correlated with surrounding weather stations. Specifically, the Company used the HDD value for each 24-hour

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2 "R is a language and environment for statistical computing and graphics. It is a GNU project which is similar to the "S" language and environment which was developed at Bell Laboratories (formerly AT&T, now Lucent Technologies). R can be considered as a different implementation of S. There are some important differences, but much code written for S runs unaltered under R. R is available as Free Software under the terms of the Free Software Foundation's GNU General Public License in source code form. It compiles and runs on a wide variety of UNIX platforms and similar systems (including FreeBSD and Linux), Windows and MacOS." (Source: The R Project for Statistical Computing)

3 Sendout includes both Sales and supplier service ("Customer Choice") customer requirements.

period of 10 a.m. to 10 a.m., which constitutes the gas day, and therefore, corresponds to the same daily time period of observation of the sendout data.

Based on its observations of the historical relationship between total sendout and HDD, the Company chose to develop its regression equation as a segmented model, a *"regression model where the relationships between the response and one or more explanatory variables are piecewise linear, namely represented by two or more straight lines connected at unknown values: these values are usually referred as breakpoints."* (Source: "segmented: an R package to fit regression models with broken-line relationships," R News, Volume 8/1, May 2008, page 20).

Since a significant portion of the Company's sendout is due to space heating usage and space heating only occurs when average air temperatures fall below a certain level, the segmented model serves as an excellent starting point for modeling the relationship between sendout and HDD. Linear modeling of sendout is appropriate since the Company has not observed any non-linear characteristics in sendout at cold temperatures as can be seen in Chart III-C-1.

In the tables below, Intercept is the MMBtu sendout predicted at HDD=0, Slope1 is the MMBtu/HDD usage below the Breakpoint HDD level, Slope2 is the incremental MMBtu/HDD usage above the Breakpoint HDD level, the Standard Error is expressed in MMBtus, and the Breakpoint HDD is the HDD value at which spaceheating equipment is observed to turn on. The signs of the Slope1 and Slope2 coefficients (positive) imply that as temperatures get colder and HDD increases in value, then sendout will increase, which agrees with what the Company observes.

Based on observations of daily sendout, the Company has observed that weekday and weekend sendout requirements are different at similar HDD levels. The Company’s regression equations include a second independent variable, a weekday/weekend dummy variable, set to zero for Mondays through Thursdays, 1 on Fridays and Sundays, and 2 on Saturdays. The sign of the coefficient (negative) implies that, for a given HDD level, loads will be lower on Friday-Sunday versus Monday-Thursday (weekend vs. workweek).

Finally, the Company has observed a correlation between lagged temperature and the residuals of the above equation and it added a third independent variable: the difference between HDD on day *t* and mean of the HDD on day *t-1* and day *t-2*. The differences were used in lieu of the actual lagged values to avoid correlation among the independent variables. 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 introduction of the third independent variable added another incremental improvement in the adjusted R^2 of the equations. The sign of the coefficient (negative) implies that, if a day is colder than the average of the previous two days, the increase in sendout will be somewhat lower than what would be forecast without the coefficient, and vice versa.

The table below lists the Providence regression results from 2007/08 through 2012/13.

Split Year	Intercept	Slope1	Slope2	Weekend	Lagged Delta HDD	Standard Error	Adjusted R^2	Breakpoint HDD
2007/08	39,487.0	463.4	3,568.1	-2,020.4	-527.4	6,983	0.9806	7.37
2008/09	39,516.8	468.8	3,595.2	-1,913.2	-665.7	6,217	0.9864	7.83
2009/10	38,099.3	443.6	3,832,1	-1,409.3	-710.1	6,440	0.9838	7.24
2010/11	38.961.9	543.5	3,866.8	-2,481.8	-712.0	6.823	0.9859	8.20
2011/12	39,220,4	633.6	3,876.2	-2,696.6	-818.1	6,528	0.9792	8.69
2012/13	37,170.7	639.3	4,194.6	-2,584.1	-792.9	7,065	0.9825	8.56

Segmented Regression Results for Providence sendout vs. HDD and Weekend and Lagged Delta HDD

Similarly, below are tables listing the coefficients for the final regression equation form for the Company's Westerly, Bristol & Warren, and Valley divisions.

Split Year	Intercept	Slope1	Slope2	Weekend	Lagged Delta HDD	Standard Error	Adjusted R^2	Breakpoint HDD
2007/08	1,103.59	1.27	74.36	-187.81	-6.07	261	0.9180	8.48
2008/09	1,226.95	12.21	59.07	-257.82	-9.03	196	0.9513	12.41
2009/10	1,070.24	10.33	72.72	-239.89	-11.94	191	0.9600	9.58
2010/11	1,115.80	2.37	79.32	-198.98	-9.57	174	0.9712	8.94
2011/12	1,024.50	14.37	66.28	-220.72	-15.33	190	0.9467	9.39
2012/13	1,036.49	15.38	79.77	-210.23	-15.90	187	0.9684	10.93

Segmented Regression Results for Westerly sendout vs. HDD and Weekend and Lagged Delta HDD

Split Year	Intercept	Slope1	Slope2	Weekend	Lagged Delta HDD	Standard Error	Adjusted R^2	Breakpoint HDD
2007/08	1,145.38	24.90	130.76	-149.23	-22.72	304	0.9737	9.24
2008/09	1,134.81	24.35	136.94	-150.27	-30.67	301	0.9780	10.00
2009/10	885.95	25.11	156.37	-113.24	-30.96	340	0.9713	10.24
2010/11	1,081.08	23.11	210.60	-135.81	-19.20	210	0.9847	8.43
2011/12	848.81	18.28	265.70	-89.94	-27.35	265	0.9619	9.31
2012/13	939.34	16.16	181.18	-65.30	-20.04	181	0.9825	8.56

Segmented Regression Results for Bristol & Warren sendout vs. HDD and Weekend and Lagged Delta HDD

Split Year	Intercept	Slope1	Slope2	Weekend	Lagged Delta HDD	Standard Error	Adjusted R^2	Breakpoint HDD
2007/08	9,843.65	-133.94	1,228.22	-1,406.40	-180.20	2,589	0.9621	5.71
2008/09	9.613.52	57.33	977.09	-1,352.51	-179.16	2,480	0.9650	8.33
2009/10	8,898.73	-7.51	1,108.95	-1,068.92	-229.55	2,266	0.9693	6.66
2010/11	10,201,60	-145.72	1,053.18	-1,420,68	-116.35	2,806	0.9481	4.37
2011/12	9,638.78	106.18	965.89	-1,176.90	-190.71	2,262	0.9556	8.50
2012/13	12,078.14	70.19	993.16	-972.73	-167.66	3,066	0.9348	9.22

Segmented Regression Results for Valley sendout vs. HDD and Weekend and Lagged Delta HDD

The tables above set forth the 2012/13 springboard regression coefficients for the Company's four divisions. The functional form of the equation, in pseudo code, is then:

```
Sendout = Intercept Coefficient +
          Weekend Dummy Coefficient * Weekend Dummy Variable +
          Slope1 Coefficient * min(HDD_t, Breakpoint HDD) +
          if(HDD_t<=Breakpoint HDD) {0} else {(Slope1 Coefficient
            + Slope2 Coefficient) *
            (HDD_t - Breakpoint HDD)} +
          Lagged Delta HDD Coefficient * (HDD_t - average(HDD_t-1, HDD_t-2)
```

As seen above, the adjusted R-squared values for all 2012/13 regressions are all in the range of 0.93 to 0.98, 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 HDD; (2) sendout requirements are affected by HDDs that occur over a multi-day period; and (3) sendout requirements differ by day of the week. Thus, the Company has developed a reliable regression equation to establish the basis upon which future sendout requirements can be forecast. Using its forecast of retail demand and an appropriate set of daily HDD 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.

III.D. Normalized Forecast of Customer Requirements

III.D.1 Defining Normal Year for Ratemaking Purposes

To establish the normal year's daily HDD data for ratemaking purposes, the Company calculated the average annual number of HDD for the KPVD weather station for the ten-year period ending 31 December 2011, with an average of 5,458 HDD.

The Company then prepared a "Typical Meteorological Year" by selecting, for each calendar month, the month in the KPVD weather database that most closely approximated the ten-year average HDD and standard deviation for each month. A summary of the monthly averages for the KPVD weather site is listed in the chart below.

Month	HDD	Standard Deviation
Jan	1,099	9.2
Feb	936	8.3
Mar	796	7.0
Apr	453	6.7
May	227	5.3
Jun	44	3.2
Jul	1	0.2
Aug	1	0.2
Sep	52	2.2
Oct	339	7.1
Nov	579	7.2
Dec	931	6.9
Total	5,458	

Average Monthly HDD and Average of Monthly Standard Deviations for the T.F. Green International Airport Weather Station

III.D.2. Defining Load Attributed to Customers Using Utility Capacity

Above, the Company established the 2012/13 regression equations for total throughput in its service territory. The Company's monthly retail volumes match the wholesale volumes to within 0.3 percent; hence, the Company has adequately captured all customer volumes. For the third step of the Company's forecasting methodology set forth in Section III.A, above, the Company then allocated the monthly retail volumes to the daily level based on the 2012/13 reference-year regression equations, using normal year HDD, to yield the forecast of customer requirements under normal weather conditions for its demand forecast.

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Heating Season	23,214	23,321	23,776	23,517	23,542	23,328	23,299	23,445	23,336	23,605
Non-Heating Season	9,868	9,913	9,926	9,830	9,855	9,900	9,919	9,855	9,955	9,951
Total	33,082	33,234	33,702	33,347	33,397	33,228	33,218	33,300	33,292	33,556
Per-Annum Growth		152	468	-355	50	-169	-10	82	-8	264
Per-Annum Growth (%)		0.5%	1.4%	-1.1%	0.1%	-0.5%	0.0%	0.2%	0.0%	0.8%

Base Case Normal Year Customer Requirements for Capacity Planning (BBtu)

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Heating Season	23,446	23,789	24,494	24,471	24,742	24,764	24,979	25,387	25,522	26,072
Non-Heating Season	9,966	10,112	10,225	10,229	10,357	10,509	10,634	10,671	10,888	10,991
Total	33,412	33,901	34,719	34,700	35,099	35,273	35,614	36,058	36,409	37,063
Per-Annum Growth		489	818	-19	399	173	341	444	351	654
Per-Annum Growth (%)		1.5%	2.4%	-0.1%	1.1%	0.5%	1.0%	1.2%	1.0%	1.8%

High Case Normal Year Customer Requirements for Capacity Planning (BBtu)

III.E. Planning Standards

In the fourth step of the Company's forecasting methodology, the Company determines the appropriate design-day and design-year planning standards to develop a least-cost, reliable supply portfolio over the forecast period. These planning standards, based on its cost/benefit analysis, were developed for the Company’s 2012 Plan filing and they are used for the instant filing.

III.E.1 Normal Year for Standards Purposes

Underlying the statistical analysis necessary to identify the appropriate design standards, the Company used recorded daily temperature values based on observations at the KPVD weather site for the period January 1977 through December 2010. Specifically, the Company used maximum and minimum temperatures (in ^{o}F) observed at KPVD. This data was available from the National Weather Service and Weather Underground, Inc. Average daily temperatures (from 12 midnight to 12 midnight) were calculated and rounded to one decimal place of precision.

The Company then used a Monte Carlo simulation method to generate synthetic daily temperature values for Providence, RI for purposes of determining its normal year for planning standards purposes. The application of this Monte Carlo method provides the Company with a much larger time series of daily temperature values on which to base its standards.

Since it is important to model resource utilization using realistic weather scenarios, the Company could not directly take the mean of the 4,096 Monte Carlo values for each calendar day to define its normal year. The Company needed to design a "Typical Meteorological Year" which would be actual observed weather patterns that would, on average, represent the normally-expected year. From the Monte Carlo dataset, the Company calculated for each calendar month the mean monthly air temperature, as well as the mean of the monthly standard deviations of the air temperature within each calendar month. It then referred back to the 34 years of actual data on record and, for each calendar month, it selected the month in the Providence, RI weather database that most closely approximated the average temperature and standard deviation for each month. Since the actual values never exactly equaled the target monthly value, the Company then scaled the actual daily values by the ratio of the target mean temperature from its Monte Carlo analysis to the actual mean temperature for each month. Lastly, the Company's Typical Meteorological Year was converted from temperature to HDD for modeling purposes. The normal year is defined as 5,645.3 HDD (rounded to 5,645 HDD) with a standard deviation of 261.59 HDD. Within the normal year, the coldest expected day is 56.3 HDD with a standard deviation of 5.08 HDD.

The Company then prepared a "Typical Meteorological Year" by selecting, for each calendar month, the month in the KPVD weather database that most closely approximated the average HDD and standard deviation for each month.

III.E.2. Design Year and Design Day Planning Standards

The Company's planning standards represent the defined weather conditions and consequent sendout requirement that must be met by the Company's resource portfolio. The Company's design year and design day standards are listed in the chart below.

Design Year and Design Day Criteria

Element	Value
Design Year HDD	6,168
Frequency of Occurrence	1 / 43.76 years
Design Day HDD	68
Frequency of Occurrence	1 / 109.64 years

As described below, the Company's analysis of the design year and design day standards demonstrate that these standards are appropriate.

III.E.2.a. Design Day Standard

In 2012, the Company examined the cost of potential customer curtailments through a cost-benefit analysis. Chart III-E-1 shows the cumulative probability distribution and the frequency of occurrence of HDD levels greater than the mean peak day. Chart III-E-1 shows the cumulative probability distribution and the frequency of occurrence of HDD levels greater than the mean peak day. Chart III-E-1 also shows, given the current peak period heating coefficient of 5,514.19 MMBtus/HDD, 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 HDD level[4].

In the event of a service disruption, there are several types of damages that customers could experience. For example, the Company's residential customers would potentially incur re-light costs and freeze-up damages. The Company'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).

4 The Company determined the equivalent number of customers using the following formula: Delta Supply/[(Heating Increment/Number of Customers)*HDD].

For this filing, the Company reexamined and updated the potential re-light costs for its moderately congested area building density. 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 the Company's planning standards, and for this filing the value is $86.57/customer.

For this filing, the Company updated its 2008 cost estimate for freeze-up damages from Marsh & McLennan. According to Marsh & McLennan, in 2008, the average cost estimate of remodeling is $20,000/customer. The Company applied the 2010 U.S. Construction Price Deflator to this value to arrive at a new figure of $18,283/customer. The Company has made the assumption that, in the event of freeze-up damages, only a portion of a residence would require remodeling, and the Company's analysis considers three levels of resulting damages: 25%, 50%, and 75%. Accordingly, the Company multiplied the freeze-up damages figure by two to represent the cost of a full remodel, so that the midpoint of the damages would align with the average cost estimate of $18,283/customer.

Given the ratio of C&I customers to the total number of customers at year-end 2010, the Company 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 the Company'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, the Company analyzed three levels of damages assuming 25 percent, 50 percent, and 75 percent of potentially affected residential customers suffer damages (as mentioned in the previous paragraph). The computed values for these three scenarios of probability-weighted costs of damages are presented in Chart III-E-2 and are shown graphically in Chart III-E-3.

Chart III-E-4 takes the HDD levels and the associated Delta Supply to estimate the costs associated with maintaining adequate deliverability at the HDD levels. The low-upgrade cost scenario is based on the cost of adding LNG 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-5.

III.E.2.a.3 Design Day Selection

In Chart III-E-5, the cost of maintaining adequate throughput capacity and the benefit of avoiding damage costs that would be incurred in relation to customer premises are compared. The intersection of the curves sets a range for design day planning purposes from approximately 62.7 to 69.5 HDD with a midpoint of 65.6 HDD. Thus, the Company’s design day standard of 68 HDD is within the range of values based on cost and benefit. Chart III-E-1 indicates that the frequency of occurrence of the Company's design day standard is once in 109.64 years.

III.E.2.b. Design Year Standard

In this filing, the Company defines its design year standard as 6,168 HDD with a probability of occurrence of once in 43.76 years.

The Company 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 reasonable weather conditions. If the Company 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. To establish an estimated annual level of HDD, for which it should plan, the Company compared the benefit of maintaining an adequate quantity of natural gas supply under all reasonable weather conditions to the probability-weighted cost of losses that might occur if supplies are not adequate.

In its 2012 Supply Plan, the Company 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, the Company 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 the Company's customers for a number of days in order to husband any remaining gas supplies. The Company 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, the Company determined the average Gross State Product per day (GSP/day) for 2010 from data from the Bureau of Economic Analysis. The economic cost to the Company's customer base per day was then calculated on the basis of the total GSP/day. First, the value for the GSP/day for the Company'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 2010 employment estimates from Moody's. Then, the value for the GSP/day for the Company's customer base was estimated by multiplying the GSP/day figure for its service territory by the 2009 U.S. Census estimated market share of natural gas in relation to all fuel types in its service territory.

To determine the number of days of interruption that a supply shortfall would represent, the Company analyzed its supply requirements at various HDD levels, assigned requirements to supply sources and, using 5,645 HDD as the baseline, estimated when supply sources would be in deficit, as well as the quantity and duration of such deficit.

The Company established a baseline of the normal annual HDD (5,645) and then determined sendout requirements for the split year 2010/11 by assigning all sendout requirements below 182,863 MMBtus/day to pipeline supply; all requirements between 182,863 and 221,543 MMBtus/day to underground storage supplies; and all requirements above 221,543 MMBtus/day to supplemental resources. The Company then analyzed the sendout requirements for HDD levels of 5,645 to 6,945 on 100 HDD increments. The Company computed these HDD scenarios by multiplying each of the days of its normal HDD days by the ratio of the desired annual total to 5,645 HDD. Using the same method of assignment of supply sources, the Company determined the annual shortfalls by supply source (Chart III-E-6).

Chart III-E-7 shows that the timing of when the shortfalls occur varies among the supply sources. Pipeline shortfalls occur late in the heating season when alternative supplies would be fairly easy to arrange. The underground storage and supplemental-resource shortfalls occur during the heating season when arranging alternative supplies would be more difficult. Chart III-E-8 summarizes the HDD levels, the probabilities of occurrence, and the shortfall by supply type.

Analysis indicates that sendout for the Company during the heating season was 61 percent residential and 39 percent commercial and industrial. Therefore, the total daily shortfall of underground storage and supplemental supplies at all HDD levels in this study can be assigned to C&I customers. For each forecast day under each HDD scenario, the daily sendout requirement was multiplied by 39 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 the Company's C&I customers that would suffer curtailment. Summing all of these values for a given HDD scenario, the Company 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-9 lists the HDD 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-9 also sets forth two scenarios of capacity that the Company acquires on behalf of its customers to avoid such damages (traditional short-haul capacity plus market-area storage and traditional long-haul capacity). Chart III-E-10 demonstrates that a planning range of 6,005 to 6,215 HDD is appropriate.

III.E.2.b.3. Design Year Selection

As a result of this analysis, the Company has determined that a current design year standard of 6,168 HDD is an appropriate level. Chart III-E-8 indicates that the frequency of occurrence of the Company's design-year standard is once in 43.76 years.

III.E.2.c. Specification of Daily Design Year HDD

To generate the daily HDD values for its design year, the Company scaled the daily values for its normal year by the ratio of the annual normal year total to the annual design year total, making any minor adjustment necessary to ensure the peak day of the design year equaled the Company's design day standard.

III.F. Forecast of Design Year Customer Requirements

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 springboard equations, which are derived from the sendout regression analysis, with its normal year daily HDD pattern and its design year daily HDD pattern to yield two springboard year estimates of normal year and design year daily customer requirements. Below are the resulting design year requirements for the demand forecast.

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Heating Season	26,062	26,207	26,718	26,427	26,455	26,215	26,182	26,346	26,224	26,526
Non-Heating Season	11,089	11,140	11,154	11,047	11,074	11,125	11,146	11,074	11,187	11,182
Total	37,151	37,346	37,872	37,473	37,529	37,339	37,328	37,421	37,411	37,708
Per-Annum Growth		196	526	-399	56	-190	-11	92	-9	297
Per-Annum Growth (%)		0.5%	1.4%	-1.1%	0.1%	-0.5%	0.0%	0.2%	0.0%	0.8%

Base Case Design Year Customer Requirements (BBtu)

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Heating Season	26,322	26,732	27,524	27,499	27,803	27,828	28,070	28,528	28,680	29,298
Non-Heating Season	11,199	11,363	11,490	11,495	11,639	11,809	11,950	11,991	12,235	12,351
Total	37,522	38,096	39,015	38,994	39,442	39,637	40,020	40,520	40,914	41,649
Per-Annum Growth		574	919	-21	448	195	384	499	395	734
Per-Annum Growth (%)		1.5%	2.4%	-0.1%	1.1%	0.5%	1.0%	1.2%	1.0%	1.8%

High Case Design Year Customer Requirements (BBtu)

IV. Design of the Resource Portfolio

IV.A. Portfolio Design

To meet load requirements under design weather conditions, the Company maintains a resource portfolio consisting of pipeline transportation, underground storage, and supplemental resources. By resource type, the Company's currently available resources to meet deliverability requirements on the peak day are as follows:

	Available Resources (Citygate quantity in Dth)
Pipeline Transportation	182,829
Underground Storage	38,714
On-System LNG	145,000
TOTAL	**366,543**

Having established its forecast of design year customer requirements, the Company evaluates its existing resource portfolio to determine if it has adequate resources over the forecast period. As part of this evaluation, the Company reviews the possible strategies for meeting customer requirements using the existing resource portfolio in a variety of circumstances. Using the SENDOUT® model (described below), the Company is able to: (1) determine the least-cost portfolio that will meet forecasted customer demand, and (2) 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 is able to make preliminary decisions on the adequacy of the resource portfolio and its ability to meet system requirements over the longer term.

Since 1996, the Company has been using the SENDOUT® model developed by New Energy Associates, now Ventyx, as its primary analytical tool in the portfolio design process. The SENDOUT® model is a linear-programming optimization software tool used to assist in evaluating, selecting and explaining long-term portfolio strategies. SENDOUT® has several advantages over previous models. For instance, there is no limit to the number of resources that can be defined. This allows the Company to model its resources more realistically and to receive more meaningful output. Second, the model allows the Company to examine the effect of various contracts on the total portfolio cost.

In that regard, the Company utilizes the SENDOUT® model 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.

IV.B Analytical Process and Assumptions

For the purpose of preparing this Long-Range Plan filing, the Company analyzed its design year and a normal year demand under base-case and high-case growth scenarios as described in Section III. In addition, the Company analyzed a cold-snap scenario using the Company's existing resource portfolio. The examination of these various scenarios enables the Company to test the adequacy and flexibility of the resource portfolio.

To perform the analysis of these three scenarios, the Company incorporated several key assumptions. First, the Company assumed that, throughout the forecast period, there is no change in the Company's service obligation to plan for the capacity requirements of firm, non-grandfathered capacity-exempt customers. Therefore, for the purposes of this filing the Company has included both Firm Sales and Firm Transportation customers that utilize the Company's firm capacity in the SENDOUT® model. Second, the Company's analysis assumes that all contracts expiring during the forecast period are renewed at the same cost, the same volume and with the same operating characteristics[5].

IV.C. Expected Available Resources

This section describes the Company's current resource portfolio and discusses any 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) transportation contracts; (2) underground storage contracts; (3) supplemental resources; (4) market area supply purchases; and, (5) gas commodity contracts. Chart IV-C-2 is a schematic of the Company's transportation and underground storage contracts effective November 1, 2013. Chart IV-C-3 is a table listing and description of the Company's resource portfolio.

IV.C.1 Transportation Contracts

The Company has capacity entitlements on multiple upstream pipelines that allow for the delivery of gas to its citygates in Rhode Island. These contracts provide access to domestic production fields as well as liquid trading points that afford the Company a level of operational flexibility to ensure the least-cost dispatch and reliable delivery of gas supplies. In general, the Company's transportation agreements provide: (a) transportation to the Company's citygates for Gulf Coast, Market Area and Canadian supplies; (b) transportation for underground storage withdrawal and injections; and, (c) the flexibility to meet any balancing and no-notice requirements.

The Company's pipeline capacity contracts fall into three primary categories. First, the Company has contract entitlements to long-haul capacity that is used to transport gas from production areas in the Gulf of Mexico to underground storage facilities located in central Pennsylvania, New York and West Virginia, and to the Company's Rhode Island city gates. Second, the Company has contract entitlements to short-haul capacity that is used to transport gas from the underground storage fields to the Company's Rhode Island city gates. These short-haul capacity entitlements are also used to ensure the deliverability of non-storage supplies to the

[5] In this Supply Plan the Company has assumed a renewal of only its off-peak season LNG refill agreement.

Company's city gates, when the capacity is not being used to transport underground storage supplies. Third, the Company has entitlements to short-haul capacity that is used to transport gas sourced in Canada to the Company's Rhode Island city gates. The Company's transportation contracts are described below:

Algonquin Gas Transmission Company: The Company has total firm capacity entitlements of 152,705 MMBtus/day on the Algonquin Gas Transmission ("Algonquin") pipeline system. Because Algonquin is not directly connected with any production or underground storage area, the Company also holds firm capacity entitlements on interstate pipelines that interconnect with the Algonquin system upstream of the Company's distribution system.

Columbia Gas Transmission, LLC: The Company has total firm capacity entitlements of 50,000 MMBtus/day on the Columbia Gas Transmission, LLC ("Columbia") pipeline system. The Columbia system is a large network stretching from the Gulf Coast to the Midwest, Mid-Atlantic and Northeast. The Company's contracts provide for specific entitlements at four different points within the system which interconnect with other major pipelines. The receipt point at Maumee, Ohio (30,000 MMBtus/day) interconnects with Western supply, Broad Run, West Virginia (10,000 MMBtus/day) interconnects with Tennessee Gas Pipeline ("Tennessee"), Eagle, Pennsylvania (3,600 MMBtus/day) interconnects with Texas Eastern Transmission, L.P. ("Texas Eastern"), and Downingtown, Pennsylvania (3,855 MMBtus/day) interconnects with Transcontinental Gas Pipe Line Company ("Transco"). All of the Company's transportation contracts with Columbia deliver into the interconnection with Algonquin at Hanover, New Jersey.

Dominion Transmission Incorporated: The Company has total firm capacity entitlements of 7,922 MMBtus/day on the Dominion Transmission Incorporation ("Dominion") pipeline system. A portion (537 MMBtu/day) of the capacity originates at the interconnection with Texas Eastern at Oakford, Pennsylvania and delivers into Texas Eastern at Leidy, Pennsylvania. The remaining capacity (7,385 MMBtu/day) originates at Dominion storage fields and delivers into either the M3 Market Area on Texas Eastern or into the Zone 4 Market Area at Ellisburg, Pennsylvania into Tennessee.

Iroquois Gas Transmission System: The Company has total firm capacity entitlements of 1,012 MMBtus/day on the Iroquois Gas Transmission ("Iroquois") pipeline system. Firm supplies from Dawn, Ontario are transported via the Iroquois system from the interconnect at Waddington, New York to the Tennessee interconnect at Wright, New York.

National Fuel Gas Supply Corporation: The Company has total firm capacity entitlements of 1,177 MMBtus/day on the National Fuel Gas Company ("National Fuel") pipeline system. This firm capacity is used to transport gas from the interconnect with Texas Eastern at Holbrook, Pennsylvania to the interconnection with Transcontinental Gas Pipe Line Company ("Transco") at Wharton, Pennsylvania.

Tennessee Gas Pipeline: The Company has total firm capacity entitlements of 68,838 MMBtus/day on the Tennessee Gas Pipeline ("Tennessee") system to its citygates. Tennessee originates in the Gulf of Mexico on three separate pipeline segments: 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 where the three legs merge into the Tennessee mainline to Zone 6 in New England. The Company's contract entitlements consist of transport volumes from Zone 0 and Zone 1 of up to 40,935 MMBtus/day to the Company's citygates located in Zone 6 and to the Company's storage fields located in Zone 4. From the Zone 4 storage market area, the Company's contract entitlements consist of transport volumes of up to 10,836 MMBtu/days to the Company's citygates. From the interconnection at Niagara in Zone 5, the Company's contract entitlements transport volumes of up to 1,067 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 1,000 MMBtus/day to the Company's citygates. Finally, the Company has contract entitlements of up to 15,000 MMBtus/day from Dracut, Massachusetts located in Zone 6 to the Company's citygates.

Texas Eastern Transmission, L.P.: The Company has total firm contract entitlements of 64,975MMBtus/day of capacity directly connected to supply and storage areas on the Texas Eastern Transmission, L.P. pipeline system ("Texas Eastern"). Texas Eastern is a large network stretching from South Texas to New Jersey, comprised of a production area and a market area. The production area, south of Arkansas and Kosciusko, Mississippi, is divided into four access areas: South Texas (STX), East Texas (ETX), West Louisiana (WLA) and East Louisiana (ELA). The Company's contracts provide for specific entitlements within and through each access area. The market area is divided into three market zones beginning with the access-area boundary: Arkansas-Mississippi, north to the Tennessee-Kentucky border and the Ohio River (M1), continuing north to the Pennsylvania – New York storage fields (M2), and from storage fields to the eastern terminus in New Jersey (M3). Contract entitlements are expressed in terms of these market zones. All of the Company's transportation contracts with Texas Eastern deliver into Texas Eastern Market Areas or the interconnection with Algonquin at either Lambertville or Hanover, New Jersey.

TransCanada PipelineLtd.: The Company has total firm capacity entitlements of 1,012MMBtus/day on the TransCanada Pipeline ("TransCanada") system. The capacity path originates at the interconnection with Union Gas Limited ("Union") at Parkway, Ontario and delivers into Iroquois at Waddington, New York.

Transcontinental Gas Pipe Line Company, LLC: The Company has total firm capacity entitlements of 1,381 MMBtus/day on the Transcontinental Gas Pipe Line Company, LLC ("Transco") pipeline system. Because Transco is not directly connected to the Company's citygates, the Company holds firm capacity entitlements on Algonquin in order to deliver to the Company's citygates.

Union Gas Limited: The Company has total firm capacity entitlements of 1,025 MMBtus/day on the Union Gas ("Union") pipeline system. The capacity path originates at Dawn, Ontario and delivers into TransCanada at Parkway, Ontario.

IV.C.2 Underground Storage Services

Underground storage capacity plays a critical role in the Company's ability to minimize costs. The Company's underground storage assets provide the Company with the ability to meet winter-season loads, while avoiding the expense of adding 365-day long-haul transportation capacity. Underground storage supplies also allow the Company to serve peak-period requirements with off-peak priced gas supply in order to manage minimum-take requirements and short-term fluctuations in demand. Furthermore, by using long-haul capacity to fill storage, the Company is able to use those resources at a high load factor. A summary of the Company's storage services are provided in the table below:

Pipeline Company	Rate Schedule	MDWQ	MSQ	MDIQ
Columbia	FSS Storage	2,545	203,957	2,545
Dominion	GSS-TE Storage	14,337	1,376,324	7,647
Dominion	GSS Storage	11,403	1,039,304	5,774
Tennessee	FS-MA Storage	21,169	815,343	5,436
Texas Eastern	SS-1 Storage	14,802	1,240,023	6,374
Texas Eastern	FSS-1 Storage	944	56,640	291
TOTAL		65,200	4,731,591	28,066

One underground storage service of note, within the Company's portfolio, is its storage swing service under Rate Schedule Firm Storage Market Area ("FSMA") on Tennessee. This storage swing option is designed to allow a daily imbalance tolerance that is equal to the Maximum Daily Withdrawal Quantity ("MDWQ") as stated in the Company's storage contract. The imbalance is treated as an automatic storage injection or withdrawal under the specific contract and assessed applicable charges under the FSMA contract. The Company has elected one of its firm storage contracts ("FSMA #501") as a storage swing option. This swing option provides vital flexibility to the Company's portfolio in order to manage daily fluctuations in load and avoid imbalance charges and/or penalties.

IV.C.3 Supplemental Resources

In addition to interstate pipeline and underground storage resources, the Company utilizes peaking supplies to meet its design requirements. Peaking supplies are a critical component of the resource mix in that 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 on-system and off-system supplemental resources to meet system needs.

IV.C.3.a On-System Peaking Resources

On-system supplemental resources are local production plants that store LNG until vaporized. It is the Company's practice to have its supplemental storage facilities full as of December 1st of each year. The Company'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 location 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. 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.

The Company's on-system supplemental resources are listed below:

Location	Facility Type	Maximum Vaporization [MMBtu/day]	Gross Storage Capacity [MMBtu]
Providence	LNG	95,000	600,000
Exeter	LNG	18,000	202,000
Cumberland	LNG	32,000	86,000

The Company's forecasted need for on-system supplemental supplies over the maximum pipeline availability is 848 BBtu for the 2013/14 base design year peak season (see Chart IV-C-1, Page 1, Base Case Design Year Heating Season).

IV.C.3.b Off-System Peaking Resources

The availability of LNG to refill the Company's local storage tanks throughout both the off-peak and peak season is a reoccurring necessity given the construct of the Company's current resource portfolio. Off-system supplemental resources relied upon during the 2013 off-peak and 2013/14 peak seasons are listed in the table below:

Contract	Description	MDQ (MMBtus)	ACQ (MMBtus)
GDF SUEZ NAESB	Firm Liquid Service (2013 Off-Peak Season)	3,850	440,000
Transcontinental Gas Pipeline LLC	Liquid Service (2013 Off-Peak Season)	---	42,837
UGI Energy Services, LLC	Liquid Service (2013/14 Peak Season)	---	26,600

In addition, as it has for the last several years, the Company has contracted for trucking arrangements in order to guarantee the availability of both trailers and drivers to truck the LNG from the source point to the Company's facilities throughout the year.

IV.C.4. Changes to the Resource Portfolio

Since the Company's last Supply Plan filing, several changes to the portfolio have been made. Below is a listing of those changes as well as a brief description of the change.

IV.C.4.a Algonquin Gas Transmission ("AGT")

The Company notified Algonquin of its intent to renew each of the Algonquin contracts described below on the basis that (1) the contracts are needed to meet customer requirements on a design day and design season basis, and (2) the contracts continue to be a least-cost resource. Furthermore, by extending the AGT contract termination date from October 31, 2014 to October 31, 2016, the Company was able to maintain a discount from maximum tariff rates on those contracts through October 31, 2014. In order to retain "Right of First Refusal" ("ROFRs") rights the Company must pay the maximum rate for the last two years of the contract.

AGT Contract 90106

AGT Contract 90106 is an existing firm transportation contract providing for the delivery of supplies from Columbia Gas Transmission and Texas Eastern Gas Transmission to the Company's service territory. In the 2013 Gas Cost Recovery Filing, R.I.P.U.C. Docket No 4436 ("2013 GCR Filing") and the Company's previous Supply Plan filed on March 8, 2012, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. The two-year extension allows the Company to maintain a discount from the maximum monthly tariff rate of $6.5734/dth for this contract. For these reasons, this contract continues to be part of the Company's least-cost portfolio approach and will be extended for a period of two years at the discounted monthly rate of $6.4213/dth for the period through and including October 31, 2014, with the contract expiring on October 31, 2016.

AGT Contract 90107

AGT Contract 90107 is an existing firm transportation contract providing for the delivery of supplies from Columbia Gas Transmission to the Company's service territory. In the 2013 GCR Filing and the Company's previous Supply Plan filed on March 8, 2012, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design-season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. The two-year extension allows the Company to maintain a discount from the maximum monthly tariff rate of $6.5734/dth for this contract. For these reasons, this contract continues to be part of the Company's least-cost portfolio approach and will be extended for a period of two years at the discounted monthly rate of $6.4213/dth for the period through and including October 31, 2014, with the contract expiring on October 31, 2016.

AGT Contract 93001ESC

AGT Contract 993001ESC is an existing small customer firm transportation contract providing for the delivery of supplies from Texas Eastern Gas Transmission to the Company's service territory. In the 2013 GCR Filing and the Company's previous Supply Plan filed on March 8, 2012, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design-season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. The two-year extension allows the Company to maintain a discount from the maximum monthly tariff rate of $2.6294/dth for this contract. For these reasons, this contract continues to be part of the Company's least-cost portfolio approach and will be extended for a period of two years at the discounted monthly rate of $2.5685/dth for the period through and including October 31, 2014, with the contract expiring on October 31, 2016.

AGT Contract 93011E

AGT Contract 993011E is an existing firm transportation contract providing for the delivery of supplies from Texas Eastern Gas Transmission to the Company's service territory. In the 2013 GCR Filing and the Company's previous Supply Plan filed on March 8, 2012, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design-season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. The two-year extension allows the Company to maintain a discount from the maximum monthly tariff rate of $6.5734/dth for this contract. For these reasons, this contract continues to be part of the Company's least-cost portfolio approach and will be extended for a period of two years at the discounted monthly rate of $6.4213/dth for the period through and including October 31, 2014, with the contract expiring on October 31, 2016.

AGT Contract 9B105

AGT Contract 9B105 is an existing firm transportation contract providing for the delivery of supplies from Texas Eastern Gas Transmission to the Company's service territory. In the 2013 GCR Filing and the Company's previous Supply Plan filed on March 8, 2012, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design-season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. The two-year extension allows the Company to maintain a discount from the maximum monthly tariff rate of $6.5734/dth for this contract. For these reasons, this contract continues to be part of the Company's least-cost portfolio approach and will be extended for a period of two years at the discounted monthly rate of $6.4213/dth for the period through and including October 31, 2014, with the contract expiring on October 31, 2016.

AGT Contract 9W009E

AGT Contract 9W009E is an existing firm transportation contract providing for the delivery of supplies from Texas Eastern Gas Transmission to the Company's service territory. In the 2013 GCR Filing and the Company's previous Supply Plan filed on March 8, 2012, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design-season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. The two-year extension allows the Company to maintain a discount from the maximum monthly tariff rate of $6.5734/dth for this contract. For these reasons, this contract continues to be part of the Company's least-cost portfolio approach and will be extended for a period of two years at the discounted monthly rate of $6.4213/dth for the period through and including October 31, 2014, with the contract expiring on October 31, 2016.

AGT Contract 93401S

AGT Contract 93401S is an existing small customer firm transportation contract providing for the delivery of supplies from Texas Eastern Gas Transmission to the Company's service territory. In the 2013 GCR Filing and the Company's previous Supply Plan filed on March 8, 2012, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design-season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. The two-year extension allows the Company to maintain a discount from the maximum monthly tariff rate of $2.6294/dth for this contract. For these reasons, this contract continues to be part of the Company's least-cost portfolio approach and will be extended for a period of two years at the discounted monthly rate of $2.5685/dth for the period through and including October 31, 2014, with the contract expiring on October 31, 2016.

AGT Contract 96004SC

AGT Contract 96004SC is an existing small customer firm transportation contract providing for the delivery of supplies from Texas Eastern Gas Transmission to The Company's service territory. In the 2013 GCR Filing and the Company's previous Supply Plan filed on March 8, 2012, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design-season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. The two-year extension allows the Company to maintain a discount from the maximum monthly tariff rate of $2.6294/dth for this contract. For these reasons, this contract continues to be part of the Company's least-cost portfolio approach and will be extended for a period of two years at the discounted monthly rate of $2.5685/dth for the period through and including October 31, 2014, with the contract expiring on October 31, 2016.

AGT Contract 9S100S

AGT Contract 9S100S is an existing small customer firm transportation contract providing for the delivery of supplies from Texas Eastern Gas Transmission to The Company's service territory. In the 2013 GCR Filing and the Company's previous Supply Plan filed on March 8, 2012, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design-season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. The two-year extension allows the Company to maintain a discount from the maximum monthly tariff rate of $2.6294/dth for this contract. For these reasons, this contract continues to be part of the Company's least-cost portfolio approach and will be extended for a period of two years at the discounted monthly rate of $2.5685/dth for the period through and including October 31, 2014, with the contract expiring on October 31, 2016.

IV.C.4.b Algonquin Incremental Market Expansion ("AIM Project")

The Company participated in Algonquin's Open Season for the Algonquin Incremental Market Expansion ("AIM Project") and has entered into a Precedent Agreement for 18,000 MMBtu/day for an initial term of fifteen years with service commencing on November 1, 2016. Along with the Precedent Agreement, the Company has executed a Negotiated Rate Agreement. The AIM Project will provide the Northeast with the opportunity to secure a cost effective, domestically produced source of supply to support current demand, as well as future growth. The project will provide 342 MMcf/d of additional capacity from Ramapo, NY to various Algonquin citygates.[6] The project will also provide access to supplies available on the Iroquois Gas Transmission System which interconnects with Algonquin at Brookfield, CT.

The Company's 18,000 dth/day of AIM capacity represents the sum of the Company's existing HubLine and East-to-West capacity on Algonquin. As of the in-service date of the AIM Project, these existing contracts will terminate. Thus, the Company is not acquiring incremental citygate delivered capacity but rather is, in effect, replacing an illiquid receipt point at Beverly, Massachusetts with a more liquid receipt point at Ramapo, New York.

IV.C.4.c Tennessee Gas Pipeline ("TGP")

During 2013, the Company extended the term of two of its Tennessee firm transportation service agreements, as described below. These agreements are necessary to ensure that National Grid will have adequate pipeline capacity to transport gas supplies. National Grid relies on these Agreements to meet the requirements of its firm gas customers and such transportation capacity is included in the Company's 2013 GCR Filing. The rate charged by Tennessee under these firm transportation agreements is regulated by the Federal Energy Regulatory Commission ("FERC") and is below the current market rate for comparable service.

<u>TGP Contract 39173</u>

TGP Contract 39173 is an existing firm transportation contract providing for the delivery of Canadian supplies from Niagara, New York (Zone 5) to the Company's service territory. In the Company's 2013 GCR Filing and updated SENDOUT® Model runs, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design-season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. For these reasons, TGP Contract 39173 continues to be part of the Company's least-cost portfolio approach and was extended for a period of five years at the existing tariff rate such that it will expire on October 31, 2019**.**

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6 The Millennium Pipeline begins in Independence, NY (Steuben County, in Southwestern NY) and terminates in Buena Vista, New York (Rockland County, near the Hudson River, just north of the NJ border). It passes through southern New York, just north of the Pennsylvania border and accesses gas supplies from the Marcellus Shale production area in northeastern Pennsylvania. The Millennium Pipeline has interconnections with several storage fields and several other pipelines, including, Tennessee Gas Pipeline, Columbia Gas Transmission, Dominion Transmission, Inc., and Algonquin Gas Transmission, and the Laser NE Gathering System, a Marcellus Shale gathering system in Northeastern Pennsylvania owned by an affiliate of Transcontinental Pipeline.

TGP Contract 1597

TGP Contract 1597 is an existing firm transportation contract providing for the delivery of both domestic supplies and storage gas volumes from the Gulf of Mexico (Zone 0) and Texas and Louisiana (Zone 1) to the Company's service territory. In the Company's 2013 GCR Filing and updated SENDOUT® Model runs, the Company demonstrated that this contract is needed to meet customer sendout requirements on a design day and design-season basis. No material changes in customer requirements have occurred that would mitigate or eliminate the need for this contract. In addition, there are no viable, economical capacity alternatives to this contract currently available in the marketplace. For these reasons, TGP Contract 1597 continues to be part of the Company's least-cost portfolio approach and was extended for a period of five years at the existing tariff rate such that it will expire October 31, 2019.

The two contracts that have been extended are "legacy"[7] transportation contracts representing least-cost resources that simply cannot be replaced with another equally reliable and cost effective resource. Because legacy transportation capacity is fully depreciated, there is no opportunity for the Company to replace these needed resources in the marketplace with alternatives that would provide the same, firm, primary delivery capacity at the same price.

IV.C.4.d Transcontinental Gas Pipeline Company ("Transco") Contract # 9081767

The Company has provided a notice of termination effective October 30, 2014. This contract provided access to supplies from the GOM delivered to the Leidy, Pennsylvania interconnect with Dominion Gas Transmission which in turn, feed the Company's downstream Texas Eastern contract (#330844) and Algonquin contracts (#90106 and 96004SC). The marketplace has evolved such that gas is readily available downstream of Transco at competitive pricing so that it is no longer necessary to maintain this Transco contract and incur the annual fixed charges.

IV.C.5. Gas Commodity

IV.C.5.a. Natural Gas Portfolio Management Plan

In Docket No. 4038, the Commission approved the Natural Gas Portfolio Management Plan ("NGPMP"), which implemented changes to the management of the Company's gas portfolio. These changes were designed to provide various financial, regulatory, and risk management benefits over the previous asset management arrangements. The Company changed the management of the gas portfolio from an external third-party asset-management agreement to a portfolio managed primarily by the Company. The Company uses its transportation contracts, underground storage contracts, peaking supplies, and supply contracts first to purchase gas supplies to economically and reliably serve sales customers and then to make additional purchases and sales that generate revenue by extracting value from any assets that are not

[7] Legacy capacity is defined herein as firm interstate pipeline transportation and storage service provided to the Company and other LDCs under FERC-approved rate schedules that were in effect upon or soon after the unbundling of the U.S. interstate pipeline system resulting from FERC Order No. 636.

required to serve customers on any day. The mix of supply, transportation, and storage contracts creates flexibility and opportunities for optimization to create value for the Company's customers. This potential optimization value is subject to market variables: the fluctuation of gas pricing, the value of temporarily unused assets, the existence of excess transportation and storage capacity, and the opportunities to optimize delivered supplies as storage fill opportunities arise. These activities were previously executed by external third-party asset managers.

IV.C.6. Future Portfolio Decisions

During the forecast period, the Company will be faced with critical decisions regarding the expiration of a significant number of its transportation, underground storage and off-system peaking contracts in its portfolio. As of January 1, 2014, the following contracts require a decision within the ten-year term of this plan:

- Forty-eight (48) of the Company's fifty-one (51) transportation contracts; and
- Ten (10) of the Company's eleven (11) underground storage contracts

During the forecast period, the Company will employ a two-step analysis to reach its conclusions on contract renewals, as well as the addition of new resources. First, depending on the type of need, the Company will canvas the marketplace to determine the availability of a replacement or new resource. And, where appropriate, the Company will solicit competitive bids to determine the lowest-cost available resource.

Then, the Company will evaluate non-price factors associated with the available replacement or new resource option. The Company will consider the flexibility, diversity, reliability and contract term to determine the least-cost, most reliable option to meet the Company's resource need.

Absent the development of new incremental capacity projects or upgrades to on-system facilities that present cost-effective alternatives to the existing resource portfolio, the Company expects to renew its existing contracts for an extended time period to maintain flexibility, diversity and reliability consistent with least-cost principles. As discussed above, pipeline rates for legacy capacity are advantaged by the significant depreciation of plant and rate base associated with legacy capacity, as well as by revenue requirement recovery at average cost-based rates. Moreover, the respective interstate pipelines flow natural gas at higher load factors (with greater billing determinants), which helps to maintain the low rates associated with these pipelines.

IV.C.6.a Future LNG Decisions

National Grid relies on imported LNG to satisfy a significant portion of its peak day requirements (approximately 31%). Prior to the summer of 2013, National Grid has relied on GDF Suez (formerly known as Distrigas) as its sole supplier of imported LNG dating back to 1971 when their Everett terminal went into service. In the spring of 2013, for the first time ever, GDF Suez limited the volume of gas available to the New England market (4 BCF) and required customers to bid on the volumes via a bidding process. The bid that National Grid submitted, and was subsequently awarded, was well above historical pricing and sufficient to secure the limited volume of 4 BCF available to the entire New England market for the refill of its LNG tanks in the off-peak period. Since the GDF Suez volumes alone did not fulfill National Grid New England's entire off-peak LNG refill requirement, the Company had to participate in a bidding process to purchase additional volumes of LNG from the Transcontinental Pipeline Company, LLC ("Transco") LNG facility in Carlstadt, NJ. The Company was able to secure an additional 300,000 Dth from Transco for the National Grid New England Companies.

As result of this limited availability of LNG for the 2013 off-peak season and the 2014 peak season, the Company joined efforts with other New England LDCs and Municipals to form an LNG Consortium. The main objectives of the LNG Consortium are (1) to find more sources of liquid and (2) balance supply with price and diversity of sources. The LNG Consortium has met with a number of parties interested in serving the New England LNG market, either through existing facilities, expansion of existing facilities or construction of new facilities.

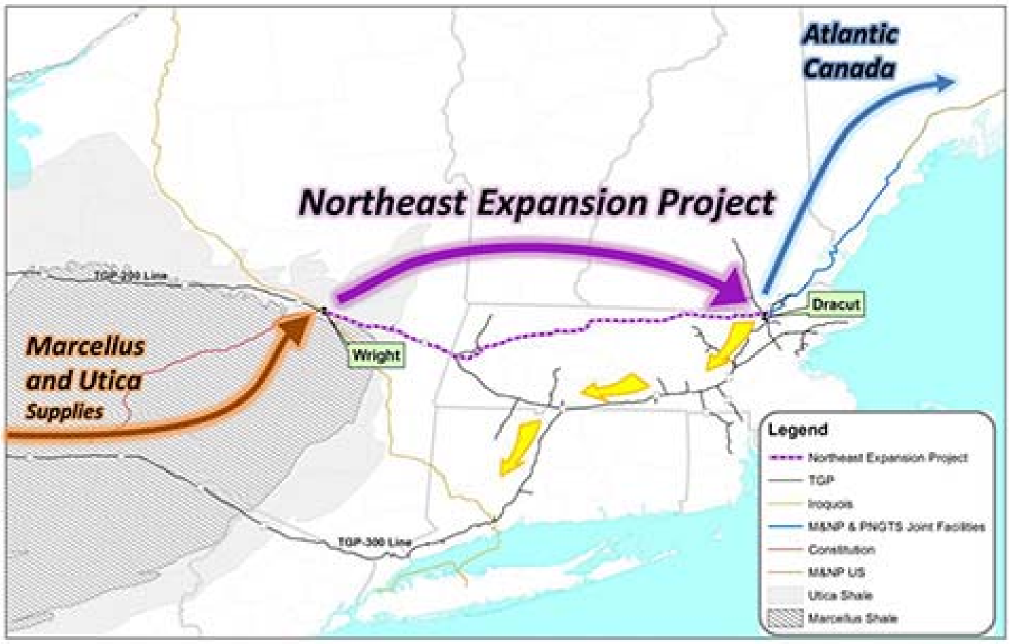
In addition to participation in the LNG Consortium, the Company is also continuing to pursue its own liquefaction opportunities. Development of on-system liquefaction will enable the Company to reduce its reliance on imported LNG. Furthermore, with all the access to abundant, low-cost domestic natural gas supplies, the Company will be able to liquefy summer gas volumes at costs competitive with historical LNG purchases and at or below anticipated higher future costs.

IV.C.7. Current and Future Supply and Capacity Projects

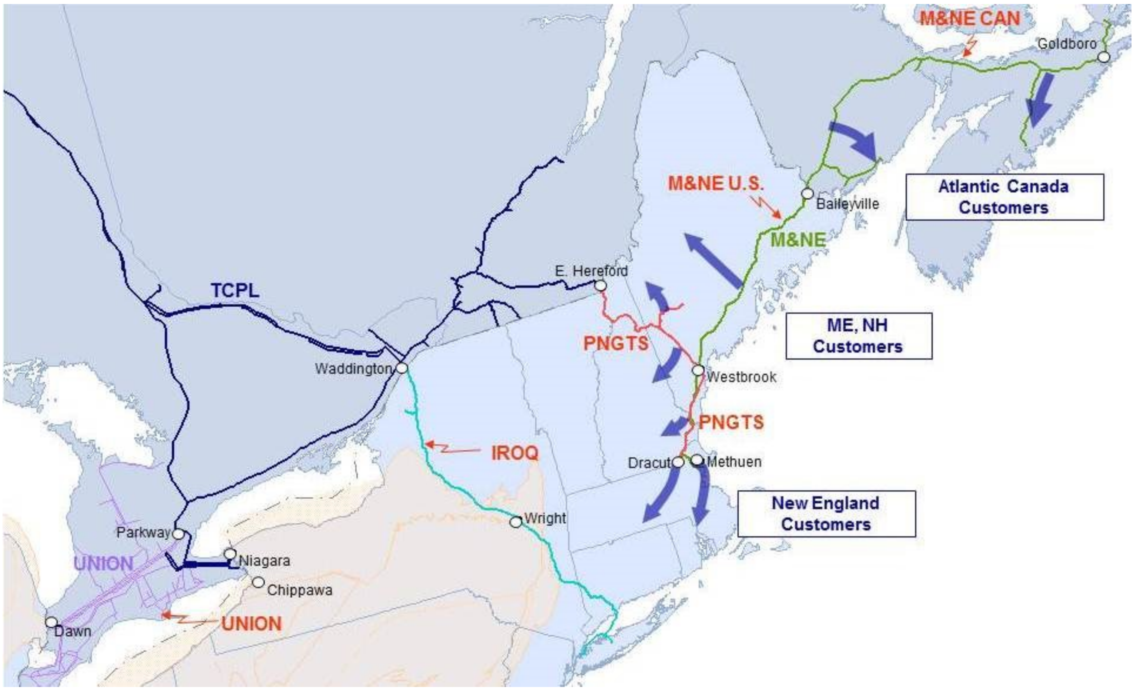
During the forecast period, the Company must continue its monitoring of the Northeast market, in particular, the effects of domestic and imported supplies on the overall supply dynamic. To date, there have been a significant number of projects which have gone into service bringing domestic shale gas from the Marcellus region to market. Construction of gathering systems by producers continues, with the additional production creating more liquidity in the shale basin. The Company's Rhode Island portfolio continues to be situated to take advantage of opportunities with a good balance of economically-priced market-area transportation on existing short-haul capacity and competitively priced supply from the Gulf of Mexico (GOM) enhanced by shale plays such as the Eagle Ford and other midcontinent shales on existing long-haul capacity. The Company will continue to monitor the relationship in price to see if these trends continue. As such, when upstream contracts are due to expire; the Company will have more data to make the appropriate decision. Therefore, as the new supply side options develop, the Company will continue to evaluate the portfolio for opportunities to reduce costs. The portfolio planning process must also consider the ability to access gas supply in a way that enhances the stability of prices to customers. Some supply sourcing options have proven to be vulnerable to severe price spikes during peak demand periods over the last few years. The Company has taken a first step to mitigate this exposure via its commitment to Algonquin's AIM Project.

Although price factors are the primary driver for contract portfolio decisions, the non-price factor of supply reliability can not be understated. A diverse portfolio with supply sourcing options helps to mitigate both price and reliability issues, however, at this juncture, the Company finds itself needing to re-evaluate the long-term reliability of its gas supply portfolio, with particular focus on LNG, and the need for a long-term solution. To that end, the Company is exploring its options to enhance portfolio reliability in three ways: through the development of on-system liquefaction, long-term LNG supply arrangements as discussed above, and incremental pipeline capacity.

The Company is also considering participation in the Tennessee Northeast Expansion Project to alleviate supply concerns at Dracut. Tennessee is proposing an upgrade to its existing 300 line combined with a greenfield pipeline build with a capacity of up to 1.2 Bcf/day originating at Wright, New York and delivering to Dracut MA and then on to existing citygates. This project would address the long-term energy needs of New England and Atlantic Canada by providing access to abundant new supplies from the Marcellus and Utica supply areas. The in-service date is expected to be November 2018.



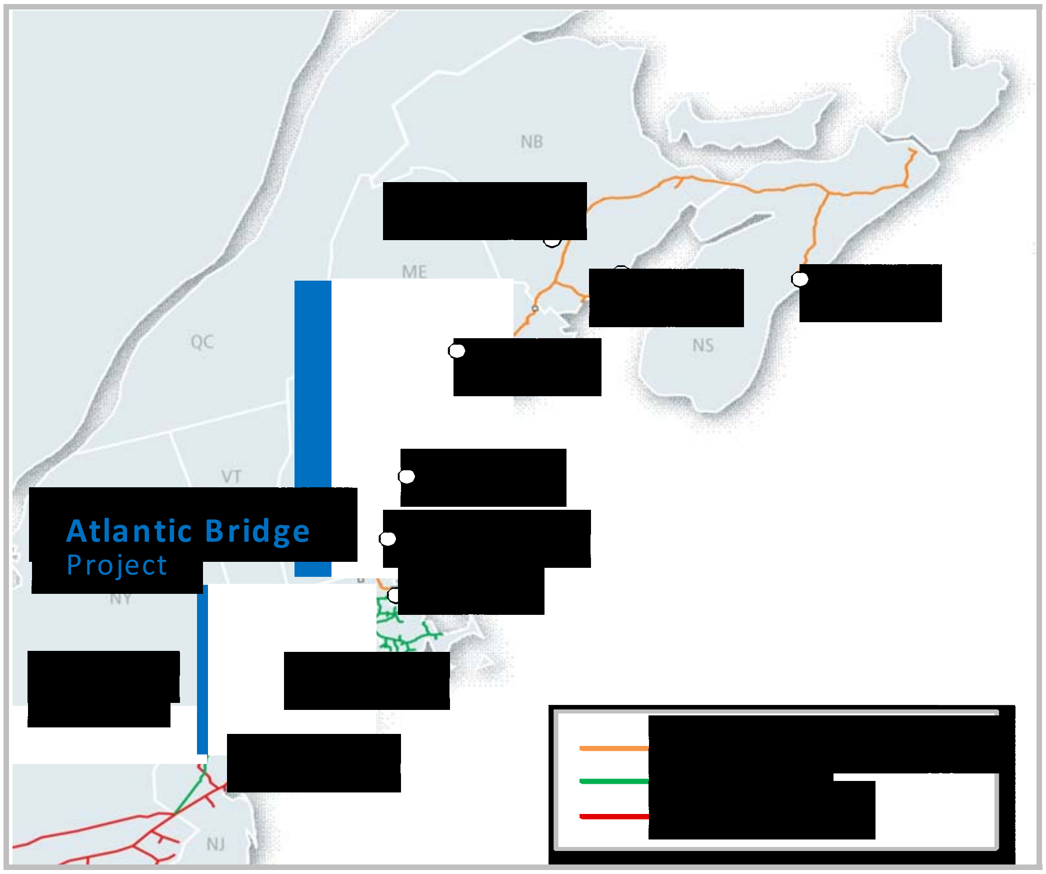
The Company also submitted a non-binding bid in the recently re-opened Portland Natural Gas Transmission System Continent-to-Coast ("C2C") expansion project. This expansion will bring additional, diverse natural gas supply options to markets in New England and Atlantic Canada. C2C will access natural gas supplies from key North American natural gas basins via TransCanada Pipeline. Atlantic Canada markets can then transport on PNGTS to an interconnection with Maritimes and Northeast Pipeline at Westbrook, Maine. Shippers interested in moving natural gas further south into New England can transport on PNGTS to interconnections with other New England natural gas pipelines at Dracut MA, Haverhill MA, and Methuen, MA. PNGTS' current capacity is 168,000 Dth/d and may rise to a total range of 300,000 to 350,000 Dth/d. The expected in-service date of C2C is November 2016. For the C2C Project to go forward, an upstream expansion of the TransCanada pipeline will be necessary, as well as possible expansion of Union Gas Transmission.



There are two other proposed major infrastructure additions that have anticipated in-service date during the forecast period to provide service to the Northeast and are described below.

- **<u>Algonquin Atlantic Bridge</u>**

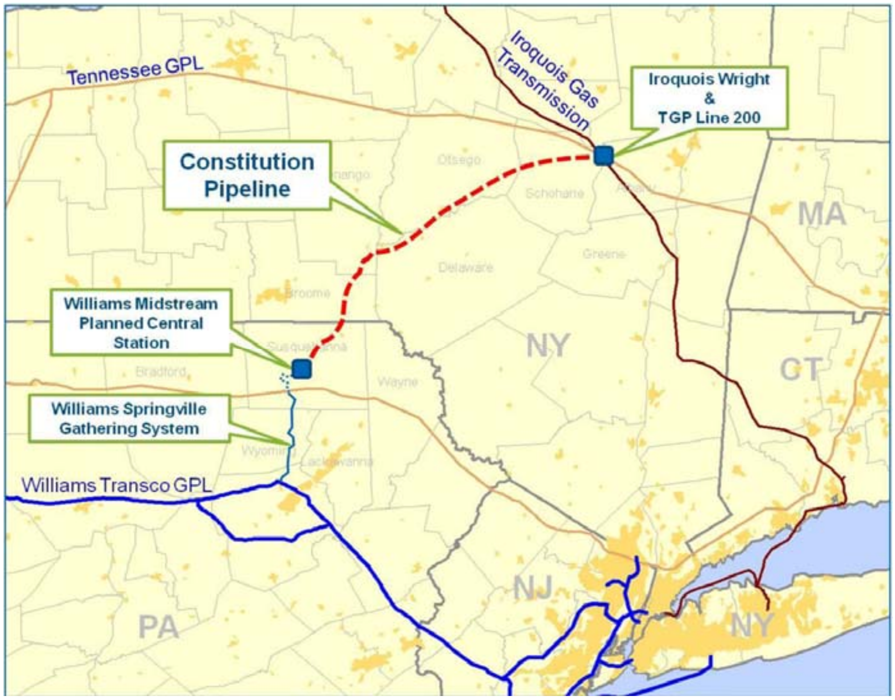
Spectra Energy is proposing to supply firm transportation of 200-400 MDth/d along the Algonquin Gas Transmission, LLC system and points north on Maritimes & Northeast Pipeline system. The 200-400 MDth/d assumes 75% of volume at Beverly, MA and or Dracut, MA and 25% of volume to Burrillville, CT and or Mendon, MA. The receipt point is Ramapo, New York and the delivery points can be Beverly, MA and/or Dracut, MA or other AGT deliveries. The proposed in-service date for the project is November 2017.



- **<u>Constitution Pipeline Project</u>**

  Williams, a leading energy infrastructure company, has partnered with Cabot Oil & Gas, Piedmont Natural Gas, and WGL Holdings to develop a major transmission pipeline project to connect abundant Appalachian natural gas supplies in northern Pennsylvania with major northeastern markets.

  The proposed Constitution Pipeline is being designed to transport natural gas that has already being produced in Pennsylvania. The approximately 124 mile pipeline is being designed with a capacity to transport 650,000 MMBtu of natural gas per day. Buried underground, the 30-inch pipeline would extend from Susquehanna County, PA, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in Schoharie County, NY. This project is expected to source the Tennessee Northeast Expansion Project.



IV.D. Adequacy of the Resource Portfolio

IV.D.1. The Design Year Forecast

For the design days as shown in Chart IV-C-1, the Company's forecast demonstrates that it relies on its pipeline and underground storage transportation contracts to meet the bulk of its customer requirements. LNG serves as the swing supply. The forecast shows that the Company would use between 87 and 123 BBtu of its 145 BBtu/day vaporization capacity to meet supply requirements. The vaporization capacity allows the Company flexibility in dispatching additional LNG if price-advantageous as well as providing reliability and diversity to its supply portfolio. The forecast also shows a need for "Other Purchased Resources". Other Purchased Resources represent additional resources that are needed over and above the available assets in the portfolio that must be acquired by the Company. The need for Other Purchased Resources is filled through the procurement of a citygate-delivered supply. This purchasing strategy minimizes the cost of the resource portfolio because the Company is able to avoid annual demand charges for capacity. However, the level at which the Company can depend on such resources varies due to a number of factors, including but not limited to: current market conditions, capacity availability, and supply availability. As such, the Company will fill the need for Other Purchases Resources through the addition of long-term capacity contracts or other long-term arrangements.

Over the base case design heating season as shown in Chart IV-C-1, the Company's forecasted customer requirements over and above its total citygate deliverability ranges between 848 and 849 BBtu/year which needs to be met by LNG resources, while the total LNG storage capacity is currently 888 BBtu. The current forecast also shows a need for Other Purchases

Resources which range between 139 and 355 BBtu/year. By division, the Company will require incremental resources delivered to both its Valley and Providence divisions during the forecasted period.

The Company's design winter weather is only one of many possible weather scenarios which could occur, and therefore, the flexibility in its LNG resources has great value. Having an asset like LNG under the Company's control, which is readily dispatchable and located in the Company's service territory, provides reliability and diversity to the entire Company resource portfolio.

IV.D.2. Cold Snap Analysis

In addition to the design-year, design-day, 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." The cold snap evaluation is performed by modeling daily sendout and observing the predicted resource usage over a specified set of HDD. For its current filing, the Company has used a 14-day cold snap occurring in the coldest 14-day period of the Company's normal year (15 Jan - 28 Jan; 540 HDD) to test the adequacy of inventories and refill requirements.

From the evaluation of January weather data from 1971 - 2013, the mean total HDD for the period 15 Jan - 28 Jan is 515 HDD with a standard deviation of 93.9 HDD. Selecting a test value of the mean plus 2.06 times the standard deviation for a once-in-50 year occurrence yields a 14-day cold snap total of 708 HDD, just 10 HDD less than the Jan 9-22, 1982 figure of 718 HDD. For its current cold snap HDD pattern, the Company took the HDD data for Jan 9- 22, 1982, removing 10 HDD from the actual data to arrive at its cold snap weather pattern. The Company then assumed normal weather up until Jan 9, followed by the cold snap period data, then followed by normal weather after the cold snap interval. For the normal year, the annual HDD are 5,458. The annual HDD for the cold snap scenario are 5,626 HDD (5458 - 540 + 708).

For the cold snap heating season as shown in Chart IV-C-1, the Company's forecasted customer requirements over and above its total citygate deliverability ranges between 749 and 849 BBtu/year, which needs to be met with LNG resources, while the total LNG storage capacity is currently 888 BBtu. The cold-snap forecast shows a need for Other Purchases Resources which ranges between 85 to 189 BBtu.

Section V
Portfolio
Recommendations

V. Gas Resource Portfolio Recommendations

V.A. Customer Choice Program

V.A.1. Planning for Customer Choice Program

As discussed in the Company's 2012 Supply Plan, the Company is responsible for planning its gas supply transportation portfolio in order to serve customer requirements for all firm customers, both sales and transportation, with the exception of those customers who are grandfathered and not required to take mandatory assignment of capacity. Thus, the Company must plan for firm sales customers, as well as FT-1 and FT-2 transportation customers.

Under the Company's Customer Choice Program, marketers are required to accept mandatory capacity assignment on behalf of customers. FT-1 customers are assigned an allocation of their peak day usage of pipeline assets only, whereas FT-2 customers are assigned an allocation of their peak day usage, including pipeline, storage and peaking assets.

The Company is recommending a review of the capacity release mechanism and its affects on the overall planning process and subsequent dispatch of assets.

V.A.2. The Effect of a Two-Pipeline System

At this time, the Company is working to determine the exact impact of the Customer Choice program on operations during this peak season. One experience identified to date concerns the issuance of Balancing Operational Flow Orders ("OFOs"). OFOs are issued in order to incentivize marketers to remain within a two percent tolerance, when comparing usage against nominations or else incur fairly substantial cashouts. When either of the upstream pipelines, Algonquin or Tennessee, issues an OFO, the Company implements a matching OFO. The Company's Terms and Conditions allow the marketers to deliver to either pipeline, so what typically occurs is that marketers make deliveries to the pipeline side that hasn't issued an OFO, which then leaves the Company to make deliveries to offset these volumes which are most often higher priced. In addition, the Company has had Capacity Exempt customers opt for Default Service. Therefore, the Company must serve these customers even though they do not plan and procure capacity on their behalf. Given the current situation in New England regarding pipeline constraints, decreasing LNG deliveries to the region, and increased demand, it is not practical to assume incremental citygate deliveries will always be available. As the current peak season winds down, the Company will be fully analyzing the impacts of the Customer Choice program and it will engage all stakeholders regarding proposed operational changes.

VI. Charts and Tables

Appendix A. Miscellaneous Weather, Sendout and Pricing Information

Section VI
Charts & Tables

Chart III-B-1

Old and New Rate Code Classes

New CSS CODE	Old Advantage code	Description	Grouping
400	1247	Residential Heating	SALES
401	1012	Residential Non-Heating	SALES
402	1301	Residential Low Income Heating	SALES
403	1101	Residential Low Income Non-Heating	SALES
404	2107	C&I Small	SALES
405	2237	C&I Medium	SALES
408	2231	TSS Medium	SALES
409	3367	C&I Low Load - Large	SALES
412	3331	TSS Large Low Load	SALES
413	3496	C&I Low Load - Extra Large	SALES
416	3431	TSS Extra Large Low Load	SALES
417	2367	C&I High Load - Large	SALES
420	2331	TSS Large High Load	SALES
421	2496	C&I High Load - Extra Large	SALES
424	2431	TSS Extra Large High Load	SALES
444	2131	TSS Small	SALES
433	05,06,07EN	NFS Medium	NON-FIRM SALES
435	08,09,10EN	NFS Large Low	NON-FIRM SALES
437	11,12,13EN	NFS Large High	NON-FIRM SALES
439	14,15,16EN	NFS XL Low	NON-FIRM SALES
441	17,18,19EN	NFS XL High	NON-FIRM SALES
406	2221	FT2 Medium	TRANSPORTATION
407	22EN	FT1 Medium	TRANSPORTATION
410	3321	FT2 Large Low	TRANSPORTATION
411	33EN	FT1 Large Low	TRANSPORTATION
414	3421	FT2 Exlarge Low	TRANSPORTATION
415	34EN	FT1 Exlarge Low	TRANSPORTATION
418	2321	FT2 Large High	TRANSPORTATION
419	23EN	FT1 Large High	TRANSPORTATION
422	2421	FT2 Exlarge High	TRANSPORTATION
423	24EN	FT1 Exlarge High	TRANSPORTATION
443	2121	FT2 Small	TRANSPORTATION
Z407	22EN	FT1 Medium	TRANSPORTATION
Z411	33EN	FT1 Large Low	TRANSPORTATION
Z415	34EN	FT1 Exlarge Low	TRANSPORTATION
Z419	23EN	FT1 Large High	TRANSPORTATION
Z423	24EN	FT1 Exlarge High	TRANSPORTATION
438	71,72,73EN	NFT Large High	NON_FIRM TRANSPORTATION
442	77,78,79EN	NFT XL High	NON_FIRM TRANSPORTATION
434	52,53,54EN	NFT Medium	NON_FIRM TRANSPORTATION
436	55,56,57EN	NFT Large Low	NON_FIRM TRANSPORTATION
440	74,75,76EN	NFT XL Low	NON_FIRM TRANSPORTATION
429	50EN	Pawtucket Power	SPECIAL CONTRACT
430	S350	Manchester St (VA Power)	SPECIAL CONTRACT
430	51EN	Virginia Power	SPECIAL CONTRACT

Econometric and Demographic Input Variables

Series	Description	Var
FHHOLDA	Total Households, (Ths., SA)	HH
FPOPA	Total Population, (Ths., SA)	POP
FNMA	Total Net Migration, (Ths., SAAR)	NMA
FGDP$A	Gross Product: Total, (Mil. Chained 2000 $)	GDPR
FYHHMEDA	Income: Median Household, ($, SAAR)	INC
FYPA	Income: Total Personal, (Mil. $, SAAR)	PI
FYPCPIA	Income: Per Capita, (2005 $, SAAR)	PIP
FYPDPIA	Income: Disposable Personal, (Mil. $, SAAR)	PID
FLBFA	Household Survey: Total Labor Force, (Ths., SA)	LBF
FLBEA	Household Survey: Total Employed, (Ths., SA)	EMP
FLBUA	Household Survey: Total Unemployed, (Ths., SA)	UEM
FLBRA	Household Survey: Unemployment Rate, (%, SA)	UER
FHSTA	Housing Starts: Total, (#, SAAR)	HST
FHST1A	Housing starts: Single-family privately owned, (# of units, SAAR)	HSS
FHSTMFA	Housing starts: Multi-family privately owned, (# of units, SAAR)	HSM
FHPNRA	Permits: Residential - Total, (# of units, SAAR)	HPT
FHPN1A	Permits: Residential - Single-Family, (# of units, SAAR)	HPS
FHPNMA	Permits: Residential - Multifamily, (# of units, SAAR)	HPM
FHX1MEDA	Median Existing Home Sales Price, (Ths., SA)	XHP
FHXAFFA	Affordability Index - Single-family Housing, (Index)	HID
FHX1A	Existing Home Sales, (Ths., SA)	XHS
FHSTKA	Housing stock: Total, (Ths., SA)	HTT
FHSTK1A	Housing stock: Single-family, (Ths., SA)	HSF
FHSTKMFA	Housing stock: Multi-family, (Ths., SA)	HMF
FHSTKOTA	Housing Stock: Other, (Ths.)	HOT
FRTFSA	Total Retail Sales, (Mil $, SAAR)	RSL
FETA	Employment: Total nonfarm, (Ths., SA)	EE
FERMA	Employment: Natural Resources & Mining, (Ths.)	ERMA
FE23A	Employment: Construction, (Ths.)	ECON
FEMFA	Employment: Manufacturing, (Ths., SA)	EMFA
FETLA	Employment: Trade, Transportation, & Utilities, (Ths.)	ETLA
FE51A	Employment: Information, (Ths.)	EINF
FEFIA	Employment: Financial Activities, (Ths., SA)	EFIA
FEPSA	Employment: Professional & Business Services, (Ths.)	EPSA
FEEHA	Employment: Education & Health Services, (Ths.)	EEHA
FELHA	Employment: Leisure & Hospitality, (Ths.)	ELHA
FE81A	Employment: Other Services (except Public Administration), (Ths.)	EOTH
FEGVA	Employment: Government, (Ths., SA)	EGVA
FEGVFA	Employment: Federal government, (Ths.)	EGVF
FEGVSA	Employment: State government, (Ths.)	EGVS
FEGVLA	Employment: Local government, (Ths.)	EGVL
FGDP	Gross Product: Total, (Mil.$)	GDP
FCPIU	CPI: Urban Consumer - All Items, (Index, 1982-84=100, SA)	CPI

Narragansett Electric Company d/b/a NATIONAL GRID
Input Economic Data

Mnemonic:	FHHOLDA.NarragansettGas	FHSTKA.NarragansettGas	FLBEA.NarragansettGas	FPOPA.NarragansettGas	FYPDPIA.NarragansettGas
Concept:	**FHHOLDA**	**FHSTKA**	**FLBEA**	**FPOPA**	**FYPDPIA**
Description:	**Number of Households: Total, (Ths.)**	**Housing Stock: Total, (Ths. of units)**	**Employment, (Ths.)**	**Total Population, (Ths.)**	**Income: Disposable Personal, (Mil. $2005)**
Source:	U.S. Census Bureau (BOC); Moody's Analytics (ECCA) Forecast	U.S. Census Bureau (BOC); Moody's Analytics (ECCA) Forecast	U.S. Bureau of Labor Statistics: Census Housing Stock Estimates - State & County (Annual); Moody's Analytics (ECCA) Forecast	U.S. Census Bureau (BOC); Moody's Analytics (ECCA) Forecast	U.S. Bureau of Economic Analysis (BEA); Moody's Analytics (ECCA) Forecast
Databank:	CTFOR.db	CTFOR.db	CTFOR.db	CTFOR.db	CTFOR.db
Native Frequency:	ANNUAL	ANNUAL	ANNUAL	ANNUAL	ANNUAL
Transformation:	None	None	None	None	None
Geography:	**Narragansett Gas**	**Narragansett Gas**	**Narragansett Gas**	**Narragansett Gas**	**Narragansett Gas**
FIP:	25017	25017	25017	25017	25017
GeoCode:	NarragansettGas	NarragansettGas	NarragansettGas	NarragansettGas	NarragansettGas
Begin Date:	12/31/1970	12/31/1971	12/31/1978	12/31/1970	12/31/1970
Last Updated:	02/25/2013	02/26/2013	02/25/2013	02/22/2013	02/26/2013
Historical End Date:	12/31/10	12/31/09	12/31/12	12/31/11	12/31/11
1990	378.93	415.37	493.67	1005.99	26239.70
1991	381.95	418.25	480.59	1010.65	25614.33
1992	383.96	420.93	483.33	1012.58	26063.39
1993	386.21	423.38	484.97	1015.11	26280.54
1994	387.83	425.65	480.67	1015.96	26305.55
1995	389.54	427.94	477.41	1017.00	26953.93
1996	392.35	430.14	489.93	1020.89	27205.30
1997	395.41	432.66	504.15	1025.35	27890.44
1998	399.00	435.14	509.55	1031.16	28889.17
1999	403.95	437.74	518.85	1040.40	29315.20
2000	409.32	440.67	520.76	1050.27	30193.28
2001	412.35	443.25	520.68	1057.14	31385.82
2002	416.22	445.85	525.72	1066.00	32892.38
2003	418.66	448.66	533.27	1071.34	33950.21
2004	420.25	451.04	526.05	1074.58	34686.45
2005	417.95	453.70	532.96	1067.92	34228.58
2006	416.26	456.47	543.97	1063.10	34830.41
2007	414.78	458.78	544.44	1057.31	35375.78
2008	414.54	460.61	527.30	1055.00	35624.45
2009	414.46	461.90	503.81	1053.65	35235.49
2010	414.50	463.51	503.58	1052.77	35954.19
2011	414.67	462.99	500.01	1050.65	35942.75
2012	411.83	462.24	499.43	1045.99	36051.41
2013	410.52	461.47	505.34	1047.42	35111.82
2014	411.25	461.05	513.77	1049.39	35213.75
2015	413.05	461.39	527.89	1051.27	35565.55
2016	415.11	462.29	539.92	1053.25	35969.63
2017	417.17	463.38	546.47	1055.37	36265.81
2018	418.70	464.38	547.72	1057.59	36196.63
2019	419.82	465.13	548.07	1059.90	36354.32
2020	421.13	465.70	548.34	1062.36	36709.04
2021	422.31	466.23	548.21	1064.84	37192.15
2022	423.61	466.75	547.47	1067.32	37731.98
2023	424.83	467.29	545.66	1069.75	38260.50
Annual Growth					
1991	0.8%	0.7%	-2.7%	0.5%	-2.4%
1992	0.5%	0.6%	0.6%	0.2%	1.8%
1993	0.6%	0.6%	0.3%	0.2%	0.8%
1994	0.4%	0.5%	-0.9%	0.1%	0.1%
1995	0.4%	0.5%	-0.7%	0.1%	2.5%
1996	0.7%	0.5%	2.6%	0.4%	0.9%
1997	0.8%	0.6%	2.9%	0.4%	2.5%
1998	0.9%	0.6%	1.1%	0.6%	3.6%
1999	1.2%	0.6%	1.8%	0.9%	1.5%
2000	1.3%	0.7%	0.4%	0.9%	3.0%
2001	0.7%	0.6%	0.0%	0.7%	3.9%
2002	0.9%	0.6%	1.0%	0.8%	4.8%
2003	0.6%	0.6%	1.4%	0.5%	3.2%
2004	0.4%	0.5%	-1.4%	0.3%	2.2%
2005	-0.5%	0.6%	1.3%	-0.6%	-1.3%
2006	-0.4%	0.6%	2.1%	-0.5%	1.8%
2007	-0.4%	0.5%	0.1%	-0.5%	1.6%
2008	-0.1%	0.4%	-3.1%	-0.2%	0.7%
2009	0.0%	0.3%	-4.5%	-0.1%	-1.1%
2010	0.0%	0.3%	0.0%	-0.1%	2.0%
2011	0.0%	-0.1%	-0.7%	-0.2%	0.0%
2012	-0.7%	-0.2%	-0.1%	-0.4%	0.3%
2013	-0.3%	-0.2%	1.2%	0.1%	-2.6%
2014	0.2%	-0.1%	1.7%	0.2%	0.3%
2015	0.4%	0.1%	2.7%	0.2%	1.0%
2016	0.5%	0.2%	2.3%	0.2%	1.1%
2017	0.5%	0.2%	1.2%	0.2%	0.8%
2018	0.4%	0.2%	0.2%	0.2%	-0.2%
2019	0.3%	0.2%	0.1%	0.2%	0.4%
2020	0.3%	0.1%	0.0%	0.2%	1.0%
2021	0.3%	0.1%	0.0%	0.2%	1.3%
2022	0.3%	0.1%	-0.1%	0.2%	1.5%
2023	0.3%	0.1%	-0.3%	0.2%	1.4%
Average Change					
2005-2013	-0.2%	0.2%	-0.7%	-0.2%	0.3%
2013-2023	0.3%	0.1%	0.8%	0.2%	0.9%

Narragansett Electric Company d/b/a NATIONAL GRID | CHART III-B-3

Forecasted Gas Deliveries by Rate Class in Dth (2013/14 - 2022/23)

		235	236	237	238	239	240	241	242	243	244
Rate Code	Rate Code Name	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
400	Residential Heating	16,488,706	16,425,085	16,563,775	16,218,747	16,195,621	16,149,294	16,046,725	16,049,283	16,000,981	16,296,412
401	Residential Non-Heating	685,875	692,027	705,409	709,840	723,984	741,066	754,671	771,432	778,486	801,434
402	Residential Low Income Heating	1,773,915	1,771,359	1,775,139	1,759,136	1,756,692	1,757,374	1,750,259	1,746,861	1,751,553	1,759,926
403	Residential Low Income Non-Heating	28,918	28,918	28,918	28,918	28,918	28,918	28,918	28,918	28,918	28,918
404	C&I Small	2,338,302	2,304,993	2,308,388	2,270,763	2,266,717	2,261,556	2,226,944	2,213,660	2,202,501	2,197,395
405	C&I Medium	3,096,957	3,081,813	3,086,285	3,036,536	3,043,426	3,027,782	3,010,086	2,993,692	2,979,888	3,013,707
406	FT2 Medium	1,454,208	1,477,111	1,511,701	1,514,847	1,538,871	1,536,841	1,550,616	1,560,792	1,553,448	1,567,092
407	FT1 Medium	644,294	647,967	659,002	662,680	664,311	665,007	667,363	662,673	665,772	668,906
408	TSS Medium	32,609	41,825	49,725	53,889	53,206	52,144	53,640	55,283	58,752	63,686
409	C&I Low Load - Large	633,000	657,458	690,196	713,997	725,529	725,918	725,473	721,695	722,894	723,818
410	FT2 Large Low	1,142,095	1,202,657	1,277,527	1,299,251	1,339,652	1,371,863	1,406,813	1,443,616	1,472,346	1,531,945
411	FT1 Large Low	810,778	817,628	833,527	836,951	839,090	839,596	842,859	835,229	838,918	842,652
412	TSS Large Low Load	43,005	61,855	80,733	94,771	103,646	112,956	124,676	134,971	149,512	163,853
413	C&I Low Load - Extra Large	169,332	186,437	205,208	217,256	225,326	230,956	238,937	240,601	245,408	250,336
414	FT2 Exlarge Low	33,718	36,224	39,764	42,530	44,317	46,155	47,883	48,516	50,027	51,572
415	FT1 Exlarge Low	972,624	992,712	1,014,749	1,023,162	1,027,762	1,033,440	1,041,973	1,040,198	1,048,105	1,055,984
416	TSS Extra Large Low Load	0	0	0	0	0	0	0	0	0	0
417	C&I High Load - Large	308,413	313,606	316,364	311,860	304,870	297,276	288,081	283,381	279,151	274,963
418	FT2 Large High	373,674	372,189	374,311	372,045	372,127	373,911	376,915	385,131	391,662	399,382
419	FT1 Large High	354,084	353,259	353,759	351,575	350,453	349,694	350,468	348,571	349,555	350,663
420	TSS Large High Load	0	0	0	0	0	0	0	0	0	0
421	C&I High Load - Extra Large	267,925	285,291	298,386	302,510	281,032	279,648	281,775	283,856	290,661	297,290
422	FT2 Exlarge High	227,761	236,205	249,008	262,138	269,676	285,155	300,757	311,977	328,505	345,546
423	FT1 Exlarge High	1,284,460	1,332,051	1,365,745	1,348,006	1,323,032	1,251,716	1,194,069	1,143,971	1,079,161	1,016,755
424	TSS Extra Large High Load	0	0	0	0	0	0	0	0	0	0
443	FT2 Small	14,807	15,450	15,662	15,824	16,265	16,545	15,766	16,239	16,067	15,978
444	TSS Small	0	0	0	0	0	0	0	0	0	0
	TOTAL	33,179,459	33,334,121	33,803,282	33,447,231	33,494,525	33,434,811	33,325,665	33,320,548	33,282,270	33,718,211
RH	Residential Heating	18,262,621	18,196,444	18,338,915	17,977,883	17,952,313	17,906,668	17,796,984	17,796,144	17,752,533	18,056,338
RN	Residential Non-heating	714,793	720,945	734,327	738,758	752,902	769,984	783,589	800,350	807,404	830,352
CH	Comm & Ind Heating	11,385,728	11,524,130	11,772,468	11,782,456	11,888,119	11,920,760	11,953,027	11,967,166	12,003,638	12,146,923
CN	Comm & Ind Non-heating	2,816,318	2,892,602	2,957,572	2,948,133	2,901,190	2,837,400	2,792,065	2,756,887	2,718,695	2,684,598
	TOTAL	33,179,459	33,334,121	33,803,282	33,447,231	33,494,525	33,434,811	33,325,665	33,320,548	33,282,270	33,718,211
	ANNUAL CHANGE										
	Residential Heating		-66,176	142,470	-361,031	-25,570	-45,645	-109,684	-839	-43,611	303,804
	Residential Non-heating		6,152	13,382	4,431	14,144	17,082	13,604	16,762	7,054	22,948
	Comm & Ind Heating		138,402	248,338	9,988	105,663	32,640	32,268	14,139	36,471	143,286
	Comm & Ind Non-heating		76,284	64,971	-9,439	-46,943	-63,791	-45,334	-35,178	-38,192	-34,098
	TOTAL		154,662	469,161	-356,051	47,294	-59,714	-109,147	-5,116	-38,278	435,941
	ANNUAL AVERAGE CHANGE										
	Residential Heating										-22,920
	Residential Non-heating										12,840
	Comm & Ind Heating										84,577
	Comm & Ind Non-heating										-14,636
	TOTAL										59,861
	ANNUAL PERCENTAGE CHANGE										
	Residential Heating		-0.4%	0.8%	-2.0%	-0.1%	-0.3%	-0.6%	0.0%	-0.2%	1.7%
	Residential Non-heating		0.9%	1.9%	0.6%	1.9%	2.3%	1.8%	2.1%	0.9%	2.8%
	Comm & Ind Heating		1.2%	2.2%	0.1%	0.9%	0.3%	0.3%	0.1%	0.3%	1.2%
	Comm & Ind Non-heating		2.7%	2.2%	-0.3%	-1.6%	-2.2%	-1.6%	-1.3%	-1.4%	-1.3%
	TOTAL		0.5%	1.4%	-1.1%	0.1%	-0.2%	-0.3%	0.0%	-0.1%	1.3%
	ANNUAL AVERAGE PERCENTAGE CHANGE										
	Residential Heating										-0.1%
	Residential Non-heating										1.7%
	Comm & Ind Heating										0.7%
	Comm & Ind Non-heating										-0.5%
	TOTAL										0.2%

Narragansett Electric Company d/b/a NATIONAL GRID — CHART III-B-4

Forecasted Number of Customers by Rate Class at End of Planning Year (2013/14 - 2022/23)

Rate Code	Rate Code Name	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
400	Residential Heating	183,959	184,114	183,883	183,699	183,639	183,756	183,942	184,094	184,230	184,366
401	Residential Non-Heating	25,744	25,696	25,688	25,697	25,713	25,731	25,750	25,772	25,792	25,812
402	Residential Low Income Heating	19,892	19,896	19,900	19,904	19,909	19,912	19,916	19,920	19,924	19,928
403	Residential Low Income Non-Heating	387	387	387	387	387	388	388	388	388	388
404	C&I Small	18,490	18,655	18,781	18,917	18,995	19,048	19,105	19,164	19,221	19,278
405	C&I Medium	3,041	3,044	3,046	3,049	3,050	3,051	3,052	3,053	3,053	3,053
406	FT2 Medium	1,247	1,257	1,264	1,269	1,274	1,280	1,285	1,290	1,295	1,300
407	FT1 Medium	413	413	414	414	414	414	415	415	415	415
408	TSS Medium	32	32	32	32	32	32	32	32	32	32
409	C&I Low Load - Large	124	125	128	127	123	118	113	108	104	100
410	FT2 Large Low	204	211	218	223	229	235	241	247	253	259
411	FT1 Large Low	127	127	127	127	127	127	127	127	127	127
412	TSS Large Low Load	4	4	4	4	4	4	4	4	4	4
413	C&I Low Load - Extra Large	6	6	6	6	6	6	6	6	6	6
414	FT2 Exlarge Low	2	2	2	2	2	2	2	2	2	2
415	FT1 Exlarge Low	10	10	10	10	10	10	10	10	10	10
416	TSS Extra Large Low Load	0	0	0	0	0	0	0	0	0	0
417	C&I High Load - Large	59	59	59	59	59	59	59	59	58	57
418	FT2 Large High	65	64	64	64	64	63	63	63	63	63
419	FT1 Large High	57	57	57	57	57	57	57	57	57	57
420	TSS Large High Load	0	0	0	0	0	0	0	0	0	0
421	C&I High Load - Extra Large	6	6	6	5	5	5	5	5	5	5
422	FT2 Exlarge High	9	9	9	9	9	9	9	9	9	9
423	FT1 Exlarge High	32	33	33	34	34	34	35	35	35	35
424	TSS Extra Large High Load	0	0	0	0	0	0	0	0	0	0
443	FT2 Small	55	55	55	55	55	55	55	55	55	55
444	TSS Small	1	1	1	1	1	1	1	1	1	1
	TOTAL	253,966	254,263	254,174	254,151	254,198	254,397	254,672	254,916	255,139	255,363
	Residential Heating	203,851	204,010	203,783	203,603	203,548	203,668	203,858	204,014	204,154	204,294
	Residential Non-heating	26,131	26,083	26,075	26,084	26,100	26,119	26,138	26,160	26,180	26,200
	Comm & Ind Heating	23,756	23,942	24,088	24,236	24,322	24,383	24,448	24,514	24,578	24,642
	Comm & Ind Non-heating	228	228	228	228	228	227	228	228	227	226
	TOTAL	253,966	254,263	254,174	254,151	254,198	254,397	254,672	254,916	255,139	255,363
	ANNUAL CHANGE										
	Residential Heating		159	-227	-180	-55	120	190	156	140	140
	Residential Non-heating		-48	-8	9	16	19	19	22	20	20
	Comm & Ind Heating		186	146	148	86	61	65	66	64	64
	Comm & Ind Non-heating		0	0	0	0	-1	1	0	-1	-1
	TOTAL		297	-89	-23	47	199	275	244	223	224
	ANNUAL AVERAGE CHANGE										
	Residential Heating										49
	Residential Non-heating										8
	Comm & Ind Heating										98
	Comm & Ind Non-heating										0
	TOTAL										155
	ANNUAL PERCENTAGE CHANGE										
	Residential Heating		0.1%	-0.1%	-0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
	Residential Non-heating		-0.2%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	Comm & Ind Heating		0.8%	0.6%	0.6%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%
	Comm & Ind Non-heating		0.0%	0.0%	0.0%	0.0%	-0.4%	0.4%	0.0%	-0.4%	-0.4%
	TOTAL		0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
	ANNUAL AVERAGE PERCENTAGE CHANGE										
	Residential Heating										0.0%
	Residential Non-heating										0.0%
	Comm & Ind Heating										0.4%
	Comm & Ind Non-heating										-0.1%
	TOTAL										0.1%

Narragansett Electric Company d/b/a NATIONAL GRID — CHART III-B-5

Forecasted Use Per Customers by Rate Class in Dth/customer (2013/14 - 2022/23)

Rate Code	Rate Code Name	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
		235	236	237	238	239	240	241	242	243	244
400	Residential Heating	89.6	89.2	90.1	88.3	88.2	87.9	87.2	87.2	86.9	88.4
401	Residential Non-Heating	26.6	26.9	27.5	27.6	28.2	28.8	29.3	29.9	30.2	31.0
402	Residential Low Income Heating	89.2	89.0	89.2	88.4	88.2	88.3	87.9	87.7	87.9	88.3
403	Residential Low Income Non-Heating	74.7	74.7	74.7	74.7	74.7	74.5	74.5	74.5	74.5	74.5
404	C&I Small	126.5	123.6	122.9	120.0	119.3	118.7	116.6	115.5	114.6	114.0
405	C&I Medium	1018.4	1012.4	1013.2	995.9	997.8	992.4	986.3	980.6	976.1	987.1
406	FT2 Medium	1166.2	1175.1	1196.0	1193.7	1207.9	1200.7	1206.7	1209.9	1199.6	1205.4
407	FT1 Medium	1560.0	1568.9	1591.8	1600.7	1604.6	1606.3	1608.1	1596.8	1604.3	1611.8
408	TSS Medium	1019.0	1307.0	1553.9	1684.0	1662.7	1629.5	1676.2	1727.6	1836.0	1990.2
409	C&I Low Load - Large	5104.8	5259.7	5392.2	5622.0	5898.6	6151.8	6420.1	6682.4	6950.9	7227.5
410	FT2 Large Low	5598.5	5699.8	5860.2	5826.2	5850.0	5837.7	5837.4	5844.6	5819.5	5911.5
411	FT1 Large Low	6384.1	6438.0	6563.2	6590.2	6607.0	6611.0	6636.7	6576.6	6605.7	6635.1
412	TSS Large Low Load	10751.2	15463.7	20183.4	23692.9	25911.6	28239.1	31169.0	33742.7	37378.0	40963.3
413	C&I Low Load - Extra Large	28222.0	31072.8	34201.3	36209.3	37554.4	38492.7	39822.9	40100.2	40901.3	41722.7
414	FT2 Exlarge Low	16859.2	18112.1	19881.9	21265.1	22158.7	23077.7	23941.3	24258.2	25013.3	25786.0
415	FT1 Exlarge Low	97262.4	99271.2	101474.9	102316.2	102776.2	103344.0	104197.3	104019.8	104810.5	105598.4
416	TSS Extra Large Low Load	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
417	C&I High Load - Large	5227.3	5315.4	5362.1	5285.8	5167.3	5038.6	4882.7	4803.1	4812.9	4822.5
418	FT2 Large High	5748.8	5815.5	5848.6	5813.2	5814.5	5935.1	5982.8	6113.2	6216.9	6339.4
419	FT1 Large High	6212.0	6197.5	6206.3	6168.0	6148.3	6135.0	6148.6	6115.3	6132.6	6152.0
420	TSS Large High Load	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
421	C&I High Load - Extra Large	44654.2	47548.6	49730.9	60501.9	56206.4	55929.6	56355.0	56771.3	58132.2	59457.9
422	FT2 Exlarge High	25306.8	26245.0	27667.6	29126.4	29964.0	31683.9	33417.4	34664.1	36500.5	38394.0
423	FT1 Exlarge High	40139.4	40365.2	41386.2	39647.2	38912.7	36815.2	34116.3	32684.9	30833.2	29050.1
424	TSS Extra Large High Load	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
443	FT2 Small	269.2	280.9	284.8	287.7	295.7	300.8	286.7	295.3	292.1	290.5
444	TSS Small	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	TOTAL	130.6	131.1	133.0	131.6	131.8	131.4	130.9	130.7	130.4	132.0
RH	Residential Heating	89.6	89.2	90.0	88.3	88.2	87.9	87.3	87.2	87.0	88.4
RN	Residential Non-heating	27.4	27.6	28.2	28.3	28.8	29.5	30.0	30.6	30.8	31.7
CH	Comm & Ind Heating	479.3	481.3	488.7	486.2	488.8	488.9	488.9	488.2	488.4	492.9
CN	Comm & Ind Non-heating	12352.3	12686.8	12971.8	12930.4	12724.5	12499.6	12245.9	12091.6	11976.6	11877.9
	TOTAL	130.6	131.1	133.0	131.6	131.8	131.4	130.9	130.7	130.4	132.0
	ANNUAL CHANGE										
	Residential Heating		-0.4	0.8	-1.7	-0.1	-0.3	-0.6	-0.1	-0.3	1.4
	Residential Non-heating		0.3	0.5	0.2	0.5	0.6	0.5	0.6	0.2	0.9
	Comm & Ind Heating		2.1	7.4	-2.6	2.6	0.1	0.0	-0.7	0.2	4.5
	Comm & Ind Non-heating		334.6	285.0	-41.4	-205.9	-225.0	-253.7	-154.3	-115.0	-98.8
	TOTAL		0.5	1.9	-1.4	0.2	-0.3	-0.6	-0.1	-0.3	1.6
	ANNUAL AVERAGE CHANGE										
	Residential Heating										-0.1
	Residential Non-heating										0.5
	Comm & Ind Heating										1.5
	Comm & Ind Non-heating										-52.7
	TOTAL										0.2
	ANNUAL PERCENTAGE CHANGE										
	Residential Heating		-0.4%	0.9%	-1.9%	-0.1%	-0.3%	-0.7%	-0.1%	-0.3%	1.6%
	Residential Non-heating		1.0%	1.9%	0.6%	1.9%	2.2%	1.7%	2.1%	0.8%	2.8%
	Comm & Ind Heating		0.4%	1.5%	-0.5%	0.5%	0.0%	0.0%	-0.2%	0.0%	0.9%
	Comm & Ind Non-heating		2.7%	2.2%	-0.3%	-1.6%	-1.8%	-2.0%	-1.3%	-1.0%	-0.8%
	TOTAL		0.3%	1.4%	-1.0%	0.1%	-0.3%	-0.4%	-0.1%	-0.2%	1.2%
	ANNUAL AVERAGE PERCENTAGE CHANGE										
	Residential Heating										-0.2%
	Residential Non-heating										1.6%
	Comm & Ind Heating										0.3%
	Comm & Ind Non-heating										-0.4%
	TOTAL										0.1%

Narragansett Electric Company d/b/a NATIONAL GRID

Historical Actual Gas Deliveries by Rate Class in Dth (2005/06 - 2012/13)

CHART III-B-6

Rate Code	Rate Code Name	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
400	Residential Heating	17,182,669	17,070,977	17,613,581	16,377,590	14,576,207	16,095,890	13,930,781	17,184,029
401	Residential Non-Heating	626,694	615,868	655,161	750,048	637,955	589,526	625,315	699,945
402	Residential Low Income Heating	0	0	0	1,435,541	1,739,300	1,707,163	1,455,599	1,709,529
403	Residential Low Income Non-Heating	0	0	0	16,128	22,032	22,180	18,931	28,505
404	C&I Small	2,234,090	2,223,383	2,282,549	2,359,367	2,216,103	2,395,459	2,040,763	2,548,200
405	C&I Medium	3,954,222	3,848,323	3,916,037	3,678,930	3,147,971	3,190,356	2,830,599	3,124,263
406	FT2 Medium	375,654	493,747	594,071	632,034	915,723	1,283,349	1,273,478	1,426,519
407	FT1 Medium	657,117	642,637	687,714	621,625	706,536	738,786	655,985	649,729
408	TSS Medium	32,389	26,001	17,657	40,267	33,779	22,018	36,309	34,913
409	C&I Low Load - Large	1,326,892	1,267,258	1,109,378	1,041,226	687,098	643,264	555,840	596,618
410	FT2 Large Low	150,578	261,947	416,487	531,942	645,379	831,951	782,258	1,101,248
411	FT1 Large Low	998,781	1,086,586	1,071,071	965,846	918,291	891,395	804,086	796,918
412	TSS Large Low Load	27,597	10,744	23,702	41,175	4,853	13,008	39,877	34,655
413	C&I Low Load - Extra Large	166,108	98,632	180,074	238,364	68,618	56,888	80,624	145,781
414	FT2 Exlarge Low	19,902	13,488	11,909	14,819	56,179	65,387	40,920	28,352
415	FT1 Exlarge Low	566,624	611,569	656,607	525,405	530,389	501,341	520,599	732,870
416	TSS Extra Large Low Load	0	0	0	0	0	4,884	2,419	2,594
417	C&I High Load - Large	496,870	413,473	477,687	392,085	280,601	267,130	250,571	311,430
418	FT2 Large High	63,945	77,717	85,687	115,196	203,409	258,776	235,582	351,035
419	FT1 Large High	411,987	475,526	430,361	386,608	544,090	366,342	319,066	353,039
420	TSS Large High Load	5,920	4,067	3,006	25,971	22,800	8,145	4,854	1,663
421	C&I High Load - Extra Large	413,955	394,806	296,941	294,851	205,065	162,115	198,743	240,930
422	FT2 Exlarge High	7,135	20,788	28,379	79,121	88,550	148,059	131,265	204,852
423	FT1 Exlarge High	3,012,948	3,721,123	3,541,742	3,307,503	3,440,905	925,285	1,012,591	1,192,511
424	TSS Extra Large High Load	0	0	0	0	0	1,777	1,355	2,988
443	FT2 Small	0	0	0	0	0	0	266	13,075
444	TSS Small	0	0	0	0	0	0	0	0
	TOTAL	32,732,075	33,378,660	34,099,799	33,871,643	31,691,835	31,190,476	27,848,674	33,516,192
	Residential Heating	17,182,669	17,070,977	17,613,581	17,813,131	16,315,507	17,803,053	15,386,379	18,893,558
	Residential Non-heating	626,694	615,868	655,161	766,176	659,986	611,706	644,245	728,449
	Comm & Ind Heating	10,509,953	10,584,314	10,967,256	10,691,000	9,930,921	10,638,086	9,664,023	11,235,736
	Comm & Ind Non-heating	4,412,760	5,107,501	4,863,802	4,601,336	4,785,421	2,137,630	2,154,027	2,658,448
	TOTAL	32,732,075	33,378,660	34,099,799	33,871,643	31,691,835	31,190,476	27,848,674	33,516,192
	ANNUAL CHANGE								
	Residential Heating		-111,692	542,604	199,551	-1,497,624	1,487,546	-2,416,674	3,507,179
	Residential Non-heating		-10,826	39,293	111,016	-106,190	-48,280	32,539	84,204
	Comm & Ind Heating		74,361	382,941	-276,256	-760,079	707,166	-974,063	1,571,713
	Comm & Ind Non-heating		694,741	-243,699	-262,466	184,086	-2,647,792	16,397	504,422
	TOTAL		646,585	721,139	-228,156	-2,179,808	-501,360	-3,341,801	5,667,518

CHARTS AND TABLES

Narragansett Electric Company d/b/a NATIONAL GRID — CHART III-B-7

Historical Number of Customers by Rate Class at End of Planning Year (2005/06 - 2012/13)

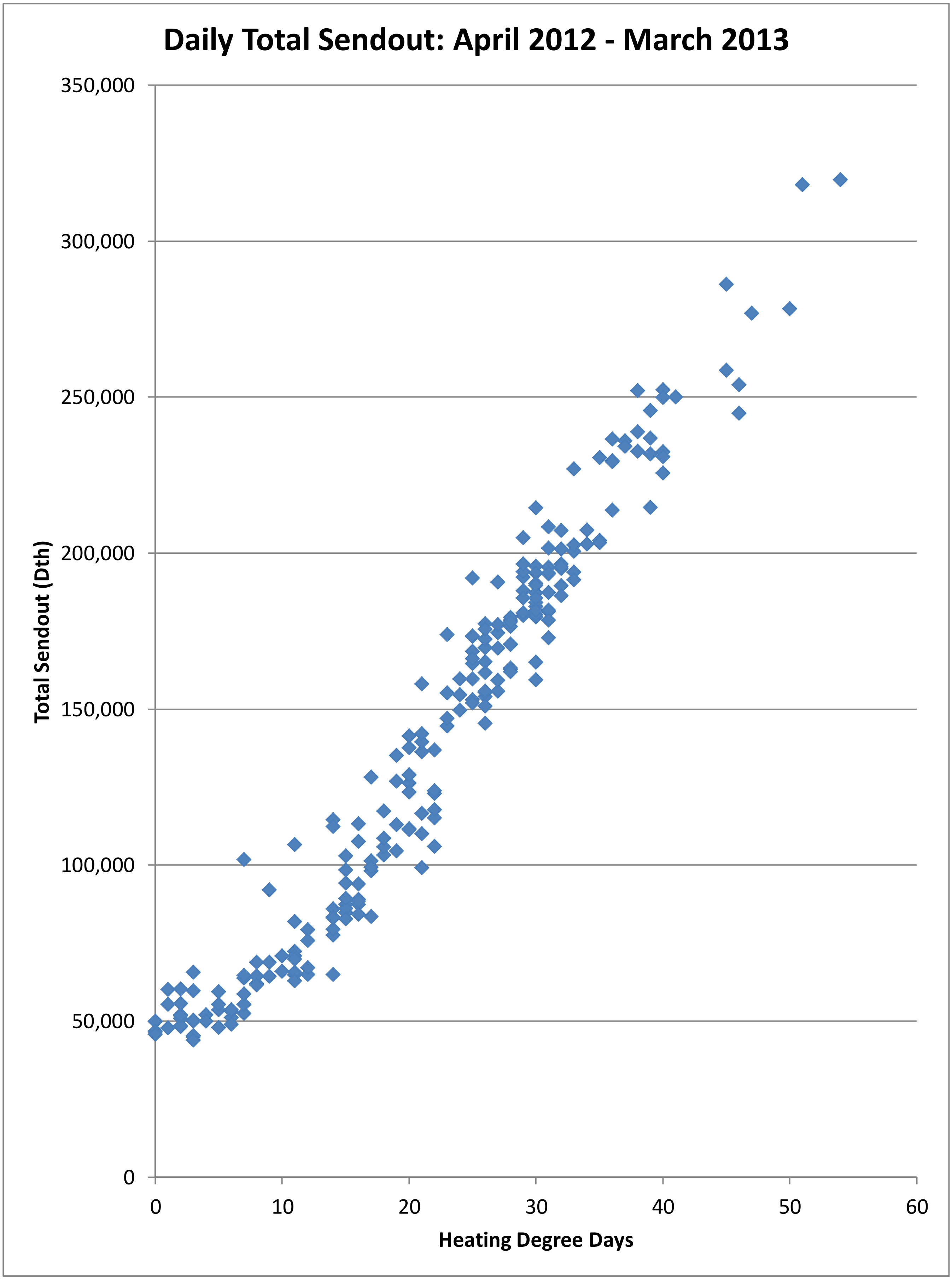
Rate Code	Rate Code Name	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
400	Residential Heating	188,985	190,389	191,776	174,750	175,754	178,451	184,453	183,103
401	Residential Non-Heating	32,693	31,991	31,308	29,718	27,304	26,770	25,995	25,870
402	Residential Low Income Heating	0	0	0	19,232	20,273	21,151	20,228	19,889
403	Residential Low Income Non-Heating	0	0	0	328	356	340	409	387
404	C&I Small	17,648	17,736	17,876	18,092	18,051	18,543	18,519	18,394
405	C&I Medium	3,599	3,600	3,499	3,231	2,963	3,011	3,050	3,040
406	FT2 Medium	352	393	399	602	848	1,091	1,205	1,224
407	FT1 Medium	394	394	404	426	418	438	424	413
408	TSS Medium	6	11	8	21	18	17	33	32
409	C&I Low Load - Large	241	213	212	142	120	116	115	123
410	FT2 Large Low	30	54	68	101	129	159	185	193
411	FT1 Large Low	173	170	147	139	151	137	125	127
412	TSS Large Low Load	1	1	6	3	3	3	11	4
413	C&I Low Load - Extra Large	7	7	9	8	2	5	6	6
414	FT2 Exlarge Low	1	1	1	3	5	4	3	2
415	FT1 Exlarge Low	24	25	21	19	23	10	7	10
416	TSS Extra Large Low Load	0	0	0	0	0	0	1	0
417	C&I High Load - Large	80	85	79	57	47	45	58	59
418	FT2 Large High	13	18	16	31	41	40	61	66
419	FT1 Large High	62	63	69	68	69	50	57	57
420	TSS Large High Load	0	0	1	4	-1	1	2	0
421	C&I High Load - Extra Large	15	12	12	8	8	8	4	6
422	FT2 Exlarge High	1	2	2	3	6	5	9	9
423	FT1 Exlarge High	47	56	48	53	57	30	29	32
424	TSS Extra Large High Load	0	0	0	0	0	0	0	0
443	FT2 Small	0	0	0	0	0	0	8	55
444	TSS Small	0	0	0	0	0	0	0	1
	TOTAL	244,372	245,221	245,961	247,039	246,645	250,425	254,997	253,102
RH	Residential Heating	188,985	190,389	191,776	193,982	196,027	199,602	204,681	202,992
RN	Residential Non-heating	32,693	31,991	31,308	30,046	27,660	27,110	26,404	26,257
CH	Comm & Ind Heating	22,476	22,605	22,650	22,787	22,731	23,534	23,692	23,624
CN	Comm & Ind Non-heating	218	236	227	224	227	179	220	229
	TOTAL	244,372	245,221	245,961	247,039	246,645	250,425	254,997	253,102
	ANNUAL CHANGE								
	Residential Heating		1,404	1,387	2,206	2,045	3,575	5,079	-1,689
	Residential Non-heating		-702	-683	-1,262	-2,386	-550	-706	-147
	Comm & Ind Heating		129	45	137	-56	803	158	-68
	Comm & Ind Non-heating		18	-9	-3	3	-48	41	9
	TOTAL		849	740	1,078	-394	3,780	4,572	-1,895
	ANNUAL AVERAGE CHANGE								
	Residential Heating								2,001
	Residential Non-heating								-919
	Comm & Ind Heating								164
	Comm & Ind Non-heating								2
	TOTAL								1,247
	ANNUAL PERCENTAGE CHANGE								
	Residential Heating		0.7%	0.7%	1.2%	1.1%	1.8%	2.5%	-0.8%
	Residential Non-heating		-2.1%	-2.1%	-4.0%	-7.9%	-2.0%	-2.6%	-0.6%
	Comm & Ind Heating		0.6%	0.2%	0.6%	-0.2%	3.5%	0.7%	-0.3%
	Comm & Ind Non-heating		8.3%	-3.8%	-1.3%	1.3%	-21.1%	22.9%	4.1%
	TOTAL		0.3%	0.3%	0.4%	-0.2%	1.5%	1.8%	-0.7%
	ANNUAL AVERAGE PERCENTAGE CHANGE								
	Residential Heating								1.0%
	Residential Non-heating								-3.1%
	Comm & Ind Heating								0.7%
	Comm & Ind Non-heating								0.7%
	TOTAL								0.5%

Narragansett Electric Company d/b/a NATIONAL GRID | CHART III-B-8

Historical Use Per Customers by Rate Class in Dth/customer (2005/06 - 2012/13)

		235	236	237	238	239	240	241	242	243	244
Rate Code	Rate Code Name	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
400	Residential Heating	89.6	89.2	90.1	88.3	88.2	87.9	87.2	87.2	86.9	88.4
401	Residential Non-Heating	26.6	26.9	27.5	27.6	28.2	28.8	29.3	29.9	30.2	31.0
402	Residential Low Income Heating	89.2	89.0	89.2	88.4	88.2	88.3	87.9	87.7	87.9	88.3
403	Residential Low Income Non-Heating	74.7	74.7	74.7	74.7	74.7	74.5	74.5	74.5	74.5	74.5
404	C&I Small	126.5	123.6	122.9	120.0	119.3	118.7	116.6	115.5	114.6	114.0
405	C&I Medium	1018.4	1012.4	1013.2	995.9	997.8	992.4	986.3	980.6	976.1	987.1
406	FT2 Medium	1166.2	1175.1	1196.0	1193.7	1207.9	1200.7	1206.7	1209.9	1199.6	1205.4
407	FT1 Medium	1560.0	1568.9	1591.8	1600.7	1604.6	1606.3	1608.1	1596.8	1604.3	1611.8
408	TSS Medium	1019.0	1307.0	1553.9	1684.0	1662.7	1629.5	1676.2	1727.6	1836.0	1990.2
409	C&I Low Load - Large	5104.8	5259.7	5392.2	5622.0	5898.6	6151.8	6420.1	6682.4	6950.9	7227.5
410	FT2 Large Low	5598.5	5699.8	5860.2	5826.2	5850.0	5837.7	5837.4	5844.6	5819.5	5911.5
411	FT1 Large Low	6384.1	6438.0	6563.2	6590.2	6607.0	6611.0	6636.7	6576.6	6605.7	6635.1
412	TSS Large Low Load	10751.2	15463.7	20183.4	23692.9	25911.6	28239.1	31169.0	33742.7	37378.0	40963.3
413	C&I Low Load - Extra Large	28222.0	31072.8	34201.3	36209.3	37554.4	38492.7	39822.9	40100.2	40901.3	41722.7
414	FT2 Exlarge Low	16859.2	18112.1	19881.9	21265.1	22158.7	23077.7	23941.3	24258.2	25013.3	25786.0
415	FT1 Exlarge Low	97262.4	99271.2	101474.9	102316.2	102776.2	103344.0	104197.3	104019.8	104810.5	105598.4
416	TSS Extra Large Low Load	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
417	C&I High Load - Large	5227.3	5315.4	5362.1	5285.8	5167.3	5038.6	4882.7	4803.1	4812.9	4822.5
418	FT2 Large High	5748.8	5815.5	5848.6	5813.2	5814.5	5935.1	5982.8	6113.2	6216.9	6339.4
419	FT1 Large High	6212.0	6197.5	6206.3	6168.0	6148.3	6135.0	6148.6	6115.3	6132.6	6152.0
420	TSS Large High Load	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
421	C&I High Load - Extra Large	44654.2	47548.6	49730.9	60501.9	56206.4	55929.6	56355.0	56771.3	58132.2	59457.9
422	FT2 Exlarge High	25306.8	26245.0	27667.6	29126.4	29964.0	31683.9	33417.4	34664.1	36500.5	38394.0
423	FT1 Exlarge High	40139.4	40365.2	41386.2	39647.2	38912.7	36815.2	34116.3	32684.9	30833.2	29050.1
424	TSS Extra Large High Load	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
443	FT2 Small	269.2	280.9	284.8	287.7	295.7	300.8	286.7	295.3	292.1	290.5
444	TSS Small	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	TOTAL	130.6	131.1	133.0	131.6	131.8	131.4	130.9	130.7	130.4	132.0
RH	Residential Heating	89.6	89.2	90.0	88.3	88.2	87.9	87.3	87.2	87.0	88.4
RN	Residential Non-heating	27.4	27.6	28.2	28.3	28.8	29.5	30.0	30.6	30.8	31.7
CH	Comm & Ind Heating	479.3	481.3	488.7	486.2	488.8	488.9	488.9	488.2	488.4	492.9
CN	Comm & Ind Non-heating	12352.3	12686.8	12971.8	12930.4	12724.5	12499.6	12245.9	12091.6	11976.6	11877.9
	TOTAL	130.6	131.1	133.0	131.6	131.8	131.4	130.9	130.7	130.4	132.0
	ANNUAL CHANGE										
	Residential Heating		-0.4	0.8	-1.7	-0.1	-0.3	-0.6	-0.1	-0.3	1.4
	Residential Non-heating		0.3	0.5	0.2	0.5	0.6	0.5	0.6	0.2	0.9
	Comm & Ind Heating		2.1	7.4	-2.6	2.6	0.1	0.0	-0.7	0.2	4.5
	Comm & Ind Non-heating		334.6	285.0	-41.4	-205.9	-225.0	-253.7	-154.3	-115.0	-98.8
	TOTAL		0.5	1.9	-1.4	0.2	-0.3	-0.6	-0.1	-0.3	1.6
	ANNUAL AVERAGE CHANGE										
	Residential Heating										-0.1
	Residential Non-heating										0.5
	Comm & Ind Heating										1.5
	Comm & Ind Non-heating										-52.7
	TOTAL										0.2
	ANNUAL PERCENTAGE CHANGE										
	Residential Heating		-0.4%	0.9%	-1.9%	-0.1%	-0.3%	-0.7%	-0.1%	-0.3%	1.6%
	Residential Non-heating		1.0%	1.9%	0.6%	1.9%	2.2%	1.7%	2.1%	0.8%	2.8%
	Comm & Ind Heating		0.4%	1.5%	-0.5%	0.5%	0.0%	0.0%	-0.2%	0.0%	0.9%
	Comm & Ind Non-heating		2.7%	2.2%	-0.3%	-1.6%	-1.8%	-2.0%	-1.3%	-1.0%	-0.8%
	TOTAL		0.3%	1.4%	-1.0%	0.1%	-0.3%	-0.4%	-0.1%	-0.2%	1.2%
	ANNUAL AVERAGE PERCENTAGE CHANGE										
	Residential Heating										-0.2%
	Residential Non-heating										1.6%
	Comm & Ind Heating										0.3%
	Comm & Ind Non-heating										-0.4%
	TOTAL										0.1%

Chart III-C-1


Daily Total Sendout: April 2012 - March 2013
Total Sendout (Dth)
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
0
10
20
30
40
50
60
Heating Degree Days

National Grid Rhode Island **Chart III-E-1**
2012 Long Range Plan

Assumptions:

Mean Peak Day =	**56.00**	**HDD**
Std Dev Peak Day =	**5.08**	**HDD**
Heating Increment =	**5,514.19**	**MMBtu/HDD**
No. of Firm Customers =	**248,500**	

HDD Level	Cumulative Probability Of Occurrence (p)	Probability Of Exceeding (1-p)	Frequency of Occurrence 1/(1-p) (years)	HDD Excess	Delta Supply (MMBtu)	Requirements Of An Average Customer At HDD Level (MMBtu/cust)	Equivalent Number of Customers
56.0	0.5000	0.5000	2.00	0.0	0	1.24	0
57.0	0.5780	0.4220	2.37	1.0	5,514	1.26	4,360
58.0	0.6530	0.3470	2.88	2.0	11,028	1.29	8,569
59.0	0.7225	0.2775	3.60	3.0	16,543	1.31	12,636
60.0	0.7843	0.2157	4.64	4.0	22,057	1.33	16,567
61.0	0.8373	0.1627	6.15	5.0	27,571	1.35	20,369
62.0	0.8811	0.1189	8.41	6.0	33,085	1.38	24,048
63.0	0.9158	0.0842	11.87	7.0	38,599	1.40	27,611
64.0	0.9422	0.0578	17.31	8.0	44,114	1.42	31,063
65.0	0.9617	0.0383	26.09	9.0	49,628	1.44	34,408
66.0	0.9754	0.0246	40.69	10.0	55,142	1.46	37,652
67.0	0.9848	0.0152	65.64	11.0	60,656	1.49	40,799
68.0	0.9909	0.0091	109.64	12.0	66,170	1.51	43,853
69.0	0.9947	0.0053	189.65	13.0	71,684	1.53	46,819
70.0	0.9971	0.0029	339.84	14.0	77,199	1.55	49,700
71.0	0.9984	0.0016	631.09	15.0	82,713	1.58	52,500
72.0	0.9992	0.0008	1214.78	16.0	88,227	1.60	55,222
73.0	0.9996	0.0004	2424.38	17.0	93,741	1.62	57,870
74.0	0.9998	0.0002	5017.51	18.0	99,255	1.64	60,446
75.0	0.9999	0.0001	10770.63	19.0	104,770	1.66	62,953
76.0	1.0000	0.0000	23984.56	20.0	110,284	1.69	65,395
77.0	1.0000	0.0000	55414.63	21.0	115,798	1.71	67,773
78.0	1.0000	0.0000	132854.83	22.0	121,312	1.73	70,090
79.0	1.0000	0.0000	330554.37	23.0	126,826	1.75	72,348
65.6	0.9705	0.0295	33.92	**(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)**

National Grid Rhode Island **Chart III-E-2**
2012 Long Range Plan

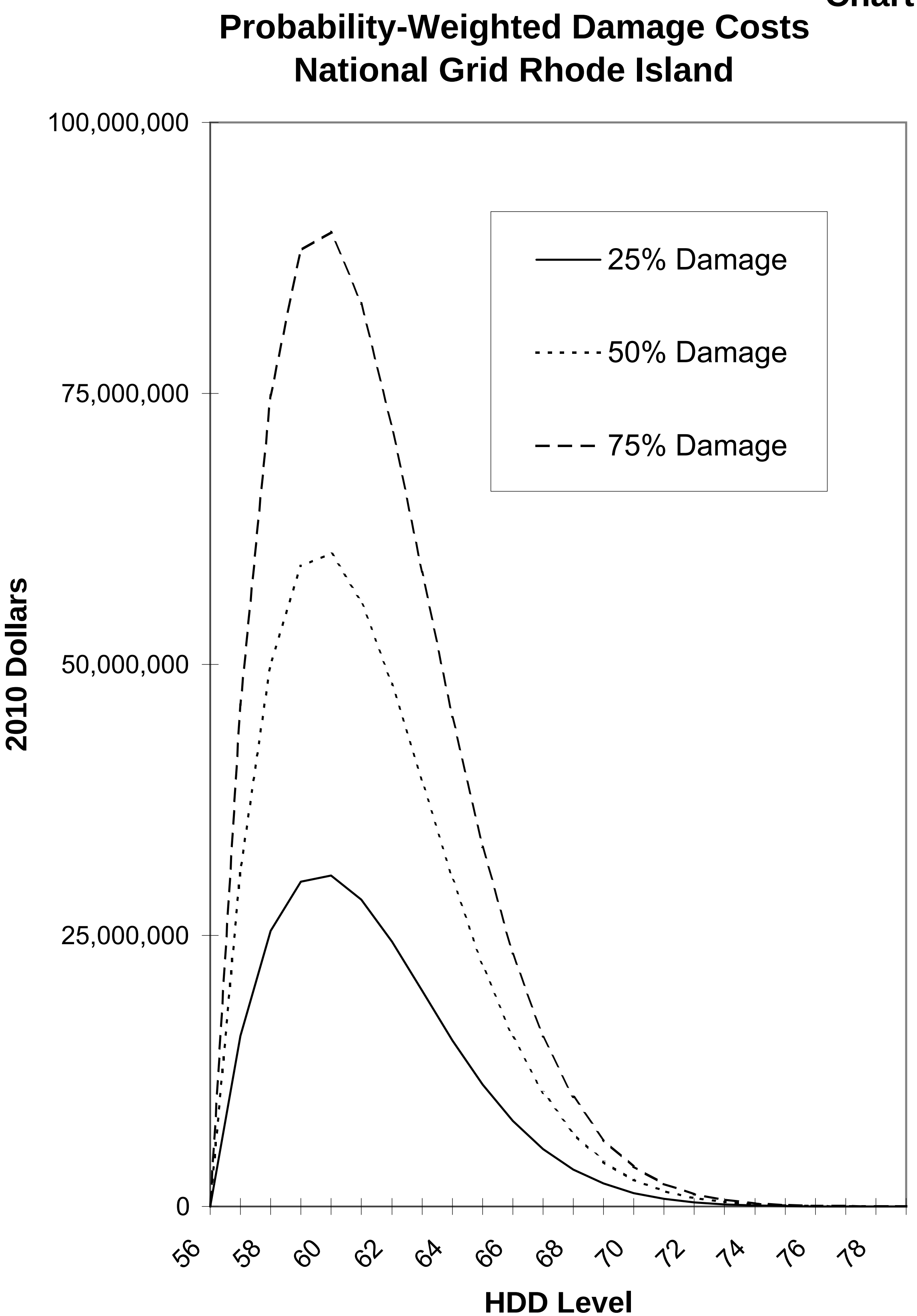
Assumptions:

Mean Peak Day =	**56.00**	**EDD**
Std Dev Peak Day =	**5.08**	**EDD**
Heating Increment =	**5,514.19**	**MMBtu/EDD**
No. of Firm Customers =	**248,500**	
	2010 dollars	
Relight Costs =	**$86.57**	**/customer**
Freeze-Up Damages =	**$36,567.16**	**/customer**
Total =	**$36,653.74**	**/customer**
2010 Average:		
Residential Customers	**225,204**	
Comm/Ind Customers	**23,296**	
Total Customers	**248,500**	
Percent C&I of Total	**9.4%**	
Cost of Interruption/Day = (2010 dollars)	**$59,665,627**	

						Probability-Weighted Cost Of Damages Given X% of Residential Customers With Damages PLUS Cost of Interruption to Comm/Ind Customers (2010 dollars)		
EDD Level	**Probability Of Exceeding (1-p)**	**Equivalent Number of Customers**	**Residential Customers**	**Comm/Ind Customers**	**Cost Of Interruption to Comm/Ind Customers**	**25%**	**50%**	**75%**
56.0	0.5000	0	0	0	$0	0	0	0
57.0	0.4220	4,360	3,951	409	$1,046,765	15,720,759	30,999,760	46,278,760
58.0	0.3470	8,569	7,766	803	$2,057,435	25,406,136	50,098,352	74,790,568
59.0	0.2775	12,636	11,451	1,185	$3,033,845	29,964,455	59,086,899	88,209,344
60.0	0.2157	16,567	15,014	1,553	$3,977,708	30,529,351	60,200,818	89,872,285
61.0	0.1627	20,369	18,459	1,910	$4,890,625	28,308,384	55,821,294	83,334,204
62.0	0.1189	24,048	21,794	2,254	$5,774,093	24,438,606	48,190,480	71,942,353
63.0	0.0842	27,611	25,023	2,588	$6,629,514	19,875,851	39,193,185	58,510,518
64.0	0.0578	31,063	28,151	2,912	$7,458,203	15,332,697	30,234,541	45,136,385
65.0	0.0383	34,408	31,182	3,226	$8,261,395	11,266,440	22,216,290	33,166,139
66.0	0.0246	37,652	34,122	3,530	$9,040,247	7,907,263	15,592,330	23,277,396
67.0	0.0152	40,799	36,974	3,825	$9,795,849	5,310,671	10,472,111	15,633,551
68.0	0.0091	43,853	39,742	4,111	$10,529,228	3,417,636	6,739,235	10,060,834
69.0	0.0053	46,819	42,430	4,389	$11,241,350	2,109,427	4,159,579	6,209,731
70.0	0.0029	49,700	45,041	4,659	$11,933,125	1,249,586	2,464,059	3,678,531
71.0	0.0016	52,500	47,578	4,922	$12,605,414	710,813	1,401,652	2,092,491
72.0	0.0008	55,222	50,045	5,177	$13,259,028	388,421	765,927	1,143,433
73.0	0.0004	57,870	52,445	5,425	$13,894,735	203,957	402,183	600,408
74.0	0.0002	60,446	54,779	5,667	$14,513,261	102,936	202,979	303,022
75.0	0.0001	62,953	57,052	5,902	$15,115,292	49,942	98,480	147,019
76.0	0.0000	65,395	59,264	6,131	$15,701,481	23,297	45,939	68,581
77.0	0.0000	67,773	61,419	6,353	$16,272,444	10,450	20,606	30,763
78.0	0.0000	70,090	63,519	6,571	$16,828,767	4,508	8,889	13,270
79.0	0.0000	72,348	65,566	6,782	$17,371,005	1,870	3,688	5,505

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

Chart III-E-3


Probability-Weighted Damage Costs
National Grid Rhode Island
100,000,000
75,000,000
50,000,000
25,000,000
0
2010 Dollars
25% Damage
50% Damage
75% Damage
56
58
60
62
64
66
68
70
72
74
76
78
HDD Level

National Grid Rhode Island **Chart III-E-4**
2012 Long Range Plan

Assumptions:

Mean Peak Day = 56.0 EDD
Std Dev Peak Day = 5.1 EDD

2010 dollars

Cost of Incr. LNG Vaporization = $65.30 /MMBtu
Cost of New Pipeline Capacity = $593.26 /MMBtu

		Low Upgrade Costs Case	High Upgrade Costs Case
EDD Level	**Delta Supply (MMBtu)**	**LNG Vaporization Costs**	**Pipeline Capacity Costs**
56.0	0	$0	$0
57.0	5,514	$360,096	$3,271,360
58.0	11,028	$720,192	$6,542,721
59.0	16,543	$1,080,289	$9,814,081
60.0	22,057	$1,440,385	$13,085,442
61.0	27,571	$1,800,481	$16,356,802
62.0	33,085	$2,160,577	$19,628,162
63.0	38,599	$2,520,673	$22,899,523
64.0	44,114	$2,880,769	$26,170,883
65.0	49,628	$3,240,866	$29,442,244
66.0	55,142	$3,600,962	$32,713,604
67.0	60,656	$3,961,058	$35,984,965
68.0	66,170	$4,321,154	$39,256,325
69.0	71,684	$4,681,250	$42,527,685
70.0	77,199	$5,041,346	$45,799,046
71.0	82,713	$5,401,443	$49,070,406
72.0	88,227	$5,761,539	$52,341,767
73.0	93,741	$6,121,635	$55,613,127
74.0	99,255	$6,481,731	$58,884,487
75.0	104,770	$6,841,827	$62,155,848
76.0	110,284	$7,201,923	$65,427,208
77.0	115,798	$7,562,020	$68,698,569
78.0	121,312	$7,922,116	$71,969,929
79.0	126,826	$8,282,212	$75,241,289

Chart III-E-5

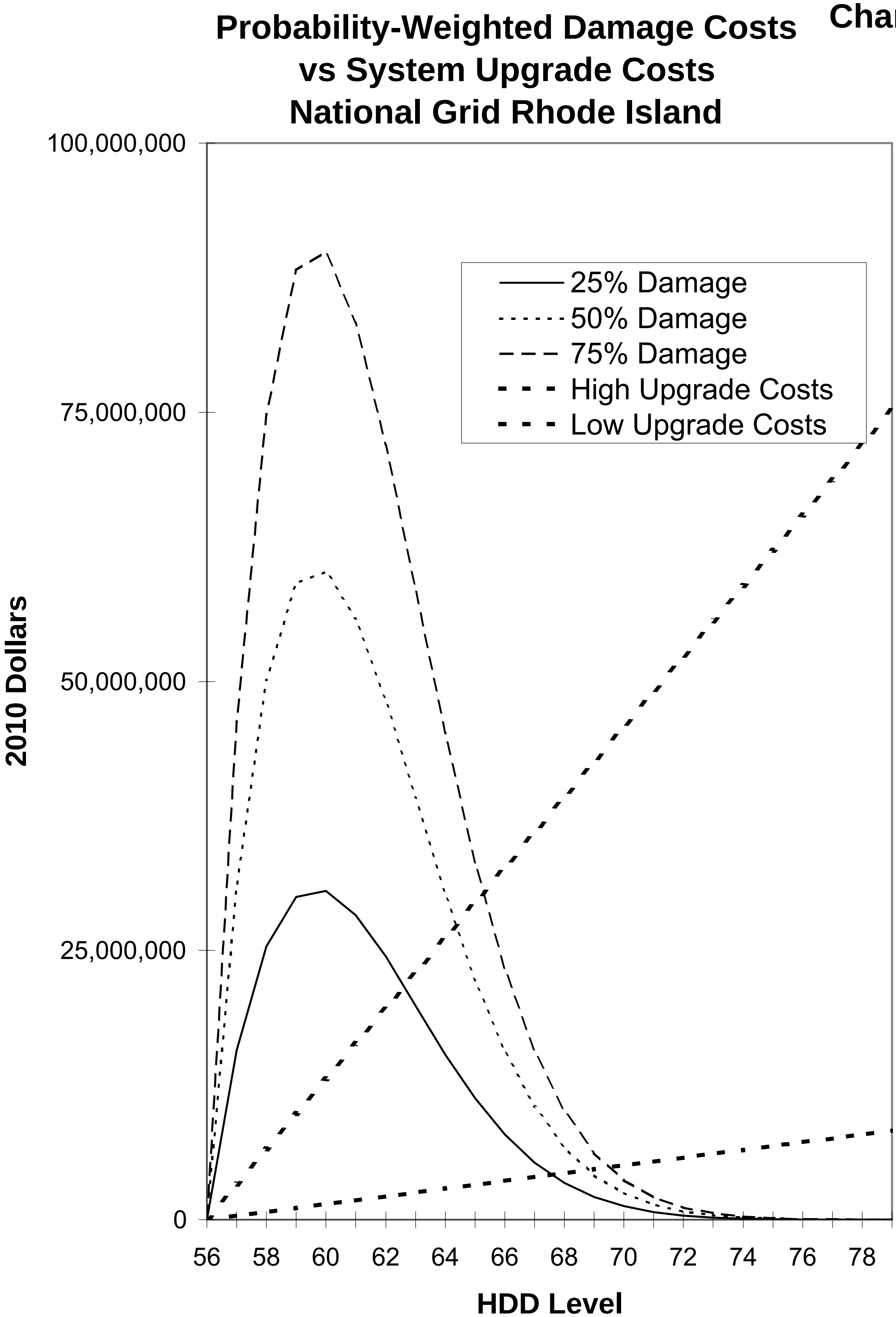
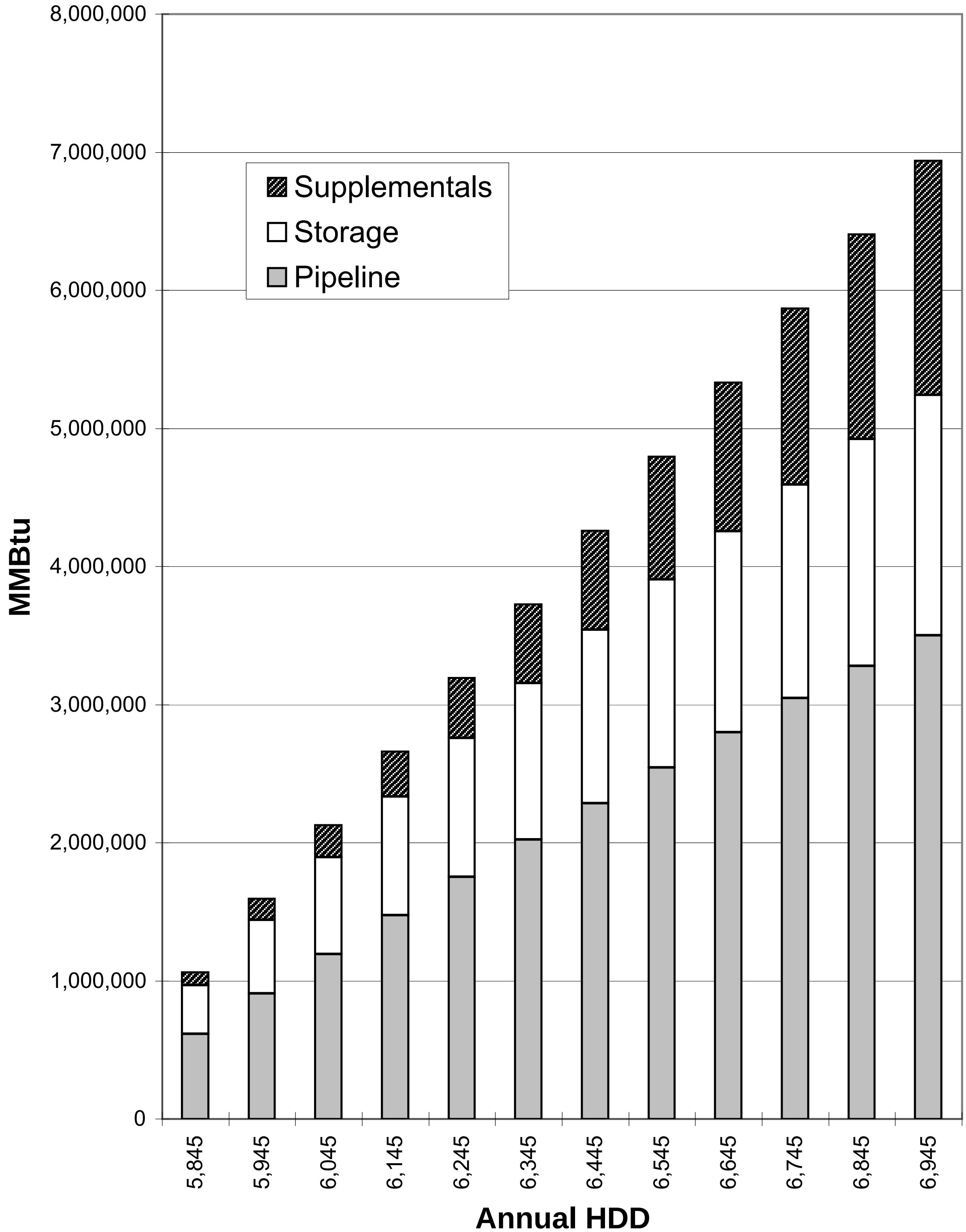

Probability-Weighted Damage Costs
vs System Upgrade Costs
National Grid Rhode Island
100,000,000
75,000,000
50,000,000
25,000,000
0
2010 Dollars
56
58
60
62
64
66
68
70
72
74
76
78
HDD Level
25% Damage
50% Damage
75% Damage
High Upgrade Costs
Low Upgrade Costs

Chart III-E-6

Supply Shortfall Versus Annual HDD Level of Design
National Grid Rhode Island



National Grid Rhode Island **Chart III-E-7**
2012 Long Range Plan

Pipeline Shortfall At HDD Level Above 5,645 Normal Annual HDD
By Month

	Annual HDD Level													
	5,645	5,745	5,845	5,945	6,045	6,145	6,245	6,345	6,445	6,545	6,645	6,745	6,845	6,945
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	13,715	242,162	466,470	683,789	886,160	1,078,967
Oct	0	314,667	617,240	909,146	1,193,760	1,476,448	1,752,660	2,023,332	2,270,442	2,301,076	2,331,744	2,362,411	2,393,079	2,423,746
Total	0	314,667	617,240	909,146	1,193,760	1,476,448	1,752,660	2,023,332	2,284,156	2,543,238	2,798,213	3,046,200	3,279,239	3,502,713

Storage Shortfall At HDD Level Above 5,645 Normal Annual HDD
By Month

	Annual HDD Level													
	5,645	5,745	5,845	5,945	6,045	6,145	6,245	6,345	6,445	6,545	6,645	6,745	6,845	6,945
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	11,902	98,166	177,705	243,476	303,440	352,925	397,316	444,256	491,834	542,032
Feb	0	33,117	178,427	328,015	460,424	505,713	549,877	587,548	626,659	661,911	690,782	718,021	748,289	773,922
Mar	0	124,824	153,189	180,133	204,705	224,290	243,856	266,889	289,663	308,616	325,189	340,949	356,963	373,712
Apr	0	14,785	18,268	21,752	25,235	28,719	32,202	35,686	38,680	39,367	42,209	45,052	47,894	50,736
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	172,725	349,884	529,900	702,267	856,888	1,003,641	1,133,599	1,258,442	1,362,819	1,455,496	1,548,277	1,644,980	1,740,402

Supplementals Shortfall At HDD Level Above 5,645 Normal Annual HDD
By Month

	Annual HDD Level													
	5,645	5,745	5,845	5,945	6,045	6,145	6,245	6,345	6,445	6,545	6,645	6,745	6,845	6,945
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	13,494	66,419	121,296
Jan	0	0	0	0	41,007	103,127	176,014	264,817	366,184	479,891	598,691	705,635	780,595	856,478
Feb	0	43,087	95,646	154,616	185,175	209,331	234,612	266,750	302,800	342,839	389,259	438,898	489,340	544,773
Mar	0	0	0	1,421	5,213	13,994	25,302	36,609	48,176	63,564	83,350	105,164	129,752	155,764
Apr	0	0	0	0	0	0	0	0	490	3,973	7,457	10,940	14,424	17,908
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	43,087	95,646	156,037	231,395	326,452	435,927	568,176	717,651	890,267	1,078,757	1,274,130	1,480,530	1,696,219

National Grid Rhode Island **Chart III-E-8**
2012 Long Range Plan

Assumptions:

Mean Annual HDD = 5,645.3 EDD
Std Dev Annual HDD = 261.6 EDD

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
5,745	0.6484	0.3516	2.84	99.7	314,667	172,725	43,087	530,479
5,845	0.7774	0.2226	4.49	199.7	617,240	349,884	95,646	1,062,769
5,945	0.8740	0.1260	7.94	299.7	909,146	529,900	156,037	1,595,083
6,045	0.9367	0.0633	15.81	399.7	1,193,760	702,267	231,395	2,127,423
6,145	0.9719	0.0281	35.65	499.7	1,476,448	856,888	326,452	2,659,788
6,245	0.9891	0.0109	91.42	599.7	1,752,660	1,003,641	435,927	3,192,228
6,345	0.9963	0.0037	267.46	699.7	2,023,332	1,133,599	568,176	3,725,108
6,445	0.9989	0.0011	894.78	799.7	2,284,156	1,258,442	717,651	4,260,249
6,545	0.9997	0.0003	3429.82	899.7	2,543,238	1,362,819	890,267	4,796,325
6,645	0.9999	0.0001	15086.09	999.7	2,798,213	1,455,496	1,078,757	5,332,466
6,745	1.0000	0.0000	76237.41	1,099.7	3,046,200	1,548,277	1,274,130	5,868,608
6,845	1.0000	0.0000	443076.13	1,199.7	3,279,239	1,644,980	1,480,530	6,404,749
6,945	1.0000	0.0000	2963889.21	1,299.7	3,502,713	1,740,402	1,696,219	6,939,335
6,168	0.9771	0.0229	43.76					
				(EDD Level MINUS Mean Peak)	**(EDD Excess TIMES Heating Increment) (MMBtu)**			

National Grid Rhode Island **Chart III-E-9**
2012 Long Range Plan

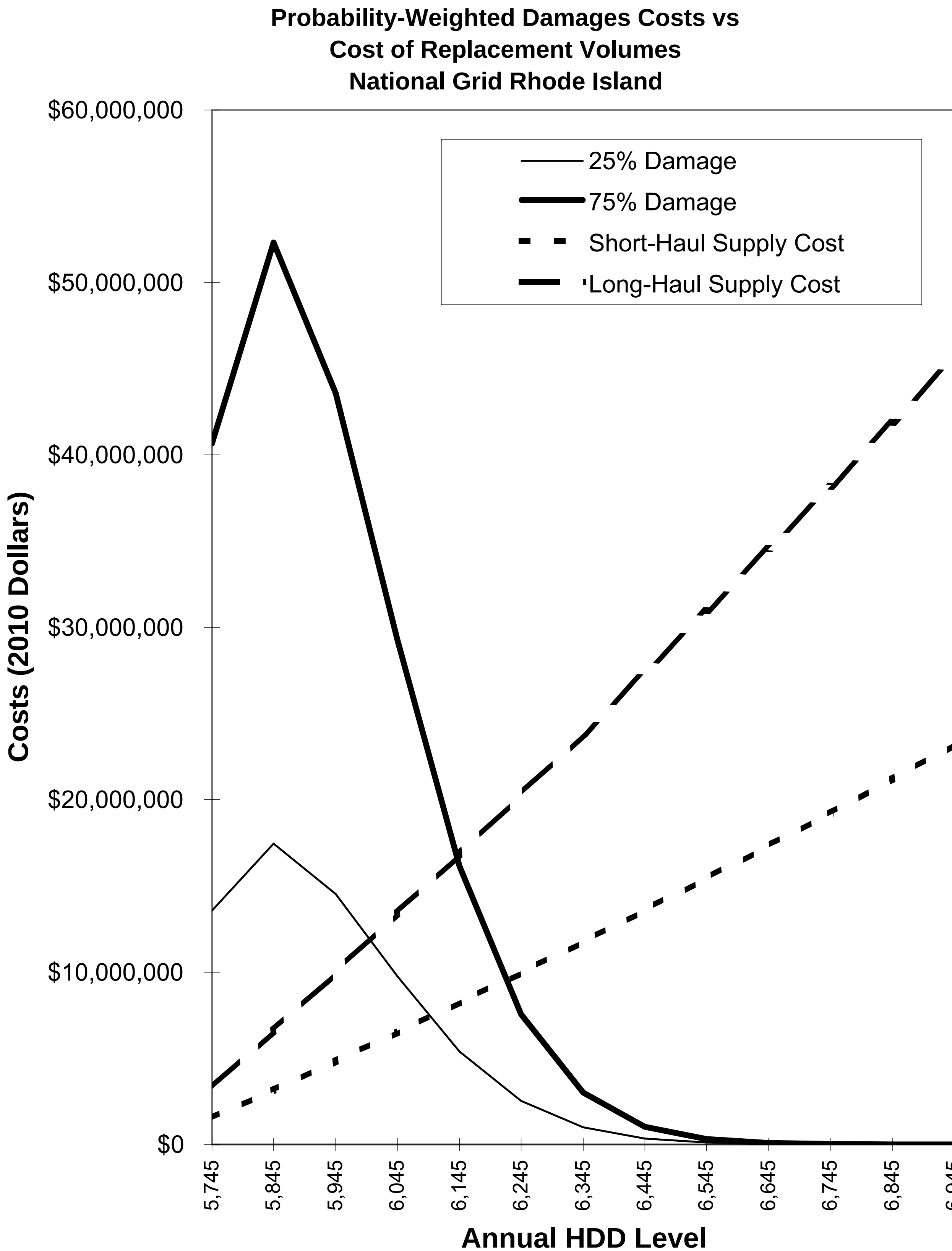
Assumptions:

Mean Annual HDD =	**5,645.3**	
Std Dev Annual HDD =	**261.6**	
Cost of Interruption/Day =	**$59,665,627**	
Peak Period Supply Cost	**$4.749**	**$/MMBtu**
Long-Haul Capacity Cost	**$593.26**	**$/MMBtu**
Offpeak Period Supply Cost	**$4.770**	
Short-Haul Capacity Cost	**$101.875**	**$/MMBtu**
Storage D1 Cost	**$18.480**	**$/MMBtu**
Storage D2 Cost	**$0.253**	**$/MMBtu**

					Costs in 2010 Dollars				Costs in 2010 Dollars	
HDD 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**
5,745	0.6484	0.3516	2.84	3	$38,536,527	$13,548,471	3,772	215,812	$1,537,934	$3,262,671
5,845	0.7774	0.2226	4.49	5	$78,346,777	$17,441,982	7,553	445,529	$3,146,870	$6,597,080
5,945	0.8740	0.1260	7.94	8	$115,278,219	$14,521,819	11,335	685,936	$4,809,565	$9,982,602
6,045	0.9367	0.0633	15.81	10	$154,309,946	$9,762,510	15,121	933,662	$6,509,408	$13,404,779
6,145	0.9719	0.0281	35.65	13	$191,653,505	$5,376,484	18,913	1,183,340	$8,219,873	$16,840,268
6,245	0.9891	0.0109	91.42	15	$229,645,982	$2,512,005	22,713	1,439,568	$9,964,199	$20,311,609
6,345	0.9963	0.0037	267.46	18	$267,528,903	$1,000,275	26,519	1,701,776	$11,739,317	$23,815,069
6,445	0.9989	0.0011	894.78	21	$306,401,397	$342,432	30,325	1,976,093	$13,575,258	$27,376,042
6,545	0.9997	0.0003	3429.82	23	$344,097,474	$100,325	34,131	2,253,087	$15,424,640	$30,949,725
6,645	0.9999	0.0001	15086.09	26	$381,858,677	$25,312	37,938	2,534,253	$17,294,981	$34,543,225
6,745	1.0000	0.0000	76237.41	28	$420,502,597	$5,516	41,744	2,822,407	$19,200,422	$38,169,915
6,845	1.0000	0.0000	443076.13	31	$462,491,451	$1,044	45,555	3,125,511	$21,181,536	$41,870,506
6,945	1.0000	0.0000	2963889.21	34	$504,553,136	$170	49,369	3,436,621	$23,203,177	$45,610,643
					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**
5,745	$115,609,580	$40,645,413
5,845	$235,040,332	$52,325,947
5,945	$345,834,658	$43,565,456
6,045	$462,929,837	$29,287,530
6,145	$574,960,514	$16,129,453
6,245	$688,937,945	$7,536,015
6,345	$802,586,708	$3,000,826
6,445	$919,204,190	$1,027,295
6,545	$1,032,292,421	$300,976
6,645	$1,145,576,031	$75,936
6,745	$1,261,507,791	$16,547
6,845	$1,387,474,352	$3,131
6,945	$1,513,659,407	$511

Chart III-E-10



National Grid Rhode Island
Comparison of Resources and Requirements
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(BBtu)

HEATING SEASON (Nov-Mar)

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	5,053	5,081	5,228	5,124	5,130	5,083	5,122	5,109	5,085	5,143
		Providence	20,080	20,192	20,774	20,361	20,383	20,198	20,354	20,300	20,205	20,438
		Warren	507	510	525	515	515	511	514	513	511	517
		Westerly	421	423	435	427	427	423	427	425	423	428
2	Fuel Reimbursement		955	984	958	947	948	943	952	944	943	946
3	Storage Refill		0	0	0	0	0	0	0	0	0	0
4	TOTAL		27,016	27,190	27,921	27,374	27,403	27,158	27,370	27,290	27,167	27,473
	RESOURCES											
5	TGP	Dawn	104	94	136	132	134	134	135	134	134	135
6		Niagara	144	163	164	163	163	163	164	163	163	163
7		Gulf Coast	5,418	5,522	5,234	5,212	5,223	5,175	5,237	5,177	5,171	5,194
8		Dracut	826	746	940	759	743	741	778	800	737	843
9		Storage	1,257	1,374	1,354	1,347	1,348	1,344	1,328	1,351	1,351	1,351
10	TET/AGT	TET Long-Haul	4,223	4,457	4,506	4,447	4,448	4,447	4,496	4,450	4,446	4,449
11		TCO	5,654	6,462	5,773	5,584	5,588	5,502	5,537	5,495	5,502	5,562
12		Transco	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	490	539	650	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	1,286	1,353	1,323	1,340	1,346	1,330	1,346
15		M3	5,909	4,442	6,020	5,526	5,486	5,410	5,425	5,444	5,398	5,475
16		Storage	1,930	2,400	1,941	1,929	1,930	1,929	1,935	1,931	1,949	1,940
17	GDF Suez	Liquid	0	0	0	0	0	0	0	0	0	0
18	LNG From Storage		848	848	849	848	848	849	848	848	849	848
19	Other Purchased Resource	Valley	164	145	201	140	139	142	148	151	139	160
		Providence	36	0	153	0	0	0	0	0	0	8
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		27,016	27,191	27,921	27,373	27,403	27,157	27,370	27,290	27,167	27,473

National Grid Rhode Island
Comparison of Resources and Requirements
Base Design Year
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NON-HEATING SEASON (Apr-Oct)

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	2,150	2,160	2,163	2,142	2,147	2,157	2,161	2,147	2,169	2,168
		Providence	8,544	8,583	8,594	8,511	8,533	8,571	8,588	8,532	8,620	8,616
		Warren	216	217	217	215	216	217	217	216	218	218
		Westerly	179	180	180	178	179	180	180	179	181	180
2	Fuel Reimbursement		404	453	396	386	387	387	391	387	389	386
3	Storage Refill		4,354	4,938	4,412	4,376	4,396	4,390	4,432	4,396	4,416	4,338
4	TOTAL		15,846	16,530	15,962	15,809	15,857	15,902	15,969	15,857	15,992	15,906
	RESOURCES											
5	TGP	Dawn	7	38	38	37	36	36	35	34	39	43
6		Niagara	148	211	231	231	231	231	231	231	231	231
7		Gulf Coast	2,684	2,634	2,340	2,289	2,293	2,295	2,335	2,299	2,310	2,259
8		Dracut	539	551	796	818	822	825	825	820	827	822
9		Storage	180	177	131	116	135	133	127	122	142	122
10	TET/AGT	TET Long-Haul	1,906	2,421	1,918	1,905	1,905	1,905	1,911	1,905	1,905	1,905
11		TCO	396	461	469	265	265	275	306	289	294	276
12		Transco	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	0	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	1,550	1,551	1,552	1,554	1,552	1,554	1,554
15		M3	8,865	8,916	8,919	7,481	7,501	7,532	7,528	7,488	7,573	7,576
16		Storage	4	5	4	1	1	1	1	1	1	1
17	GDF Suez	Liquid	983	983	983	983	983	983	983	983	983	983
18	LNG From Storage		134	134	134	134	134	134	134	134	134	134
19	Other Purchased Resource	Valley	0	0	0	0	0	0	0	0	0	0
		Providence	0	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		15,846	16,531	15,962	15,809	15,858	15,902	15,969	15,857	15,992	15,907

National Grid Rhode Island
Comparison of Resources and Requirements
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			ANNUAL									
			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	7,204	7,241	7,391	7,266	7,277	7,240	7,284	7,256	7,254	7,312
		Providence	28,624	28,775	29,368	28,873	28,916	28,770	28,943	28,832	28,825	29,054
		Warren	723	727	742	730	731	727	732	729	728	734
		Westerly	600	603	616	605	606	603	606	604	604	609
2	Fuel Reimbursement		1,358	1,437	1,354	1,333	1,335	1,330	1,343	1,331	1,332	1,332
3	Storage Refill		4,354	4,938	4,412	4,376	4,396	4,390	4,432	4,396	4,416	4,338
4	TOTAL		42,863	43,721	43,882	43,182	43,261	43,060	43,339	43,147	43,159	43,378
	RESOURCES											
5	TGP	Dawn	111	132	174	169	170	169	170	168	173	178
6		Niagara	292	374	395	394	394	394	395	394	394	394
7		Gulf Coast	8,102	8,155	7,574	7,501	7,516	7,470	7,572	7,475	7,481	7,453
8		Dracut	1,365	1,297	1,736	1,577	1,565	1,566	1,603	1,620	1,564	1,665
9		Storage	1,437	1,551	1,485	1,464	1,483	1,477	1,455	1,472	1,492	1,473
					0	0	0	0	0	0	0	0
10	TET/AGT	TET Long-Haul	6,129	6,879	6,424	6,351	6,353	6,351	6,407	6,355	6,351	6,354
11		TCO	6,050	6,923	6,243	5,849	5,853	5,777	5,843	5,784	5,796	5,838
12		Transco	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	490	539	650	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	2,836	2,904	2,876	2,894	2,898	2,884	2,900
15		M3	14,774	13,358	14,939	13,007	12,987	12,942	12,952	12,932	12,970	13,051
16		Storage	1,934	2,405	1,945	1,931	1,931	1,930	1,936	1,932	1,950	1,941
17	GDF Suez	Liquid	983	983	983	983	983	983	983	983	983	983
18	LNG From Storage		983	983	983	983	983	983	983	983	983	983
19	Other Purchased Resource	Valley	164	145	201	140	139	142	148	151	139	160
		Providence	36	0	153	0	0	0	0	0	0	8
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		42,863	43,722	43,883	43,182	43,261	43,059	43,339	43,147	43,159	43,379

National Grid Rhode Island
Comparison of Resources and Requirements
Base Design Year
(BBtu)

Base Design Day

			Jan 2014	Jan 2015	Jan 2016	Jan 2017	Jan 2018	Jan 2019	Jan 2020	Jan 2021	Jan 2022	Jan 2023
	REQUIREMENTS											
1	Firm Sendout	Valley	64	65	63	61	63	65	65	65	64	65
		Providence	252	258	250	242	250	259	260	258	256	258
		Warren	6	7	6	6	6	7	7	7	7	7
		Westerly	5	5	5	5	5	5	5	5	5	5
2	Fuel Reimbursement		10	9	9	9	9	10	10	9	9	9
3	Storage Refill		0	0	0	0	0	0	0	0	0	0
4	TOTAL		337	344	334	323	334	346	347	344	341	344
	RESOURCES											
5	TGP	Dawn	1	1	1	1	1	1	1	1	1	1
6		Niagara	1	1	1	1	1	1	1	1	1	1
7		Gulf Coast	43	43	43	43	43	43	43	43	43	43
8		Dracut	15	15	15	6	6	6	6	6	15	15
9		Storage	11	11	11	11	11	11	11	11	11	11
10	TET/AGT	TET Long-Haul	49	50	50	50	50	50	50	50	50	50
11		TCO	48	48	48	48	48	48	48	48	48	48
12		Transco	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	12	12	12	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	15	15	15	15	15	15	15
15		M3	19	16	16	12	26	12	12	12	25	14
16		Storage	25	27	27	28	14	28	28	28	14	26
17	GDF Suez	Liquid	0	0	0	0	0	0	0	0	0	0
18	LNG From Storage		104	98	87	109	113	123	123	117	111	110
19	Other Purchased Resource	Valley	9	21	23	0	6	8	8	12	6	10
		Providence	0	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		337	344	334	323	334	346	347	344	341	344

National Grid Rhode Island
Comparison of Resources and Requirements
Base Normal Year
(BBtu)

HEATING SEASON (Nov-Mar)

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	4,561	4,582	4,709	4,621	4,626	4,584	4,614	4,607	4,585	4,638
		Providence	17,827	17,909	18,404	18,059	18,078	17,914	18,033	18,004	17,920	18,127
		Warren	451	453	465	457	457	453	456	455	453	458
		Westerly	376	378	388	381	381	378	380	380	378	382
2	Fuel Reimbursement		921	960	932	916	917	912	921	913	912	916
3	Storage Refill		0	0	0	0	0	0	0	0	0	0
4	TOTAL		24,135	24,280	24,898	24,433	24,459	24,240	24,404	24,359	24,249	24,521
	RESOURCES											
5	TGP	Dawn	93	78	125	120	124	126	127	127	126	128
6		Niagara	137	163	164	163	163	163	164	163	163	163
7		Gulf Coast	5,161	5,492	5,083	5,014	5,025	4,960	5,021	4,967	4,957	4,985
8		Dracut	125	86	169	113	100	105	109	115	105	129
9		Storage	1,223	1,374	1,355	1,344	1,344	1,344	1,328	1,352	1,352	1,351
10	TET/AGT	TET Long-Haul	4,268	4,458	4,511	4,456	4,457	4,454	4,504	4,457	4,455	4,456
11		TCO	5,211	6,103	5,413	5,126	5,101	5,084	5,122	5,084	5,078	5,115
12		Transco	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	67	72	93	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	1,043	1,081	1,049	1,072	1,076	1,066	1,082
15		M3	5,189	3,735	5,719	4,966	4,954	4,794	4,785	4,864	4,787	4,945
16		Storage	1,920	2,400	1,941	1,933	1,933	1,933	1,940	1,935	1,953	1,945
17	GDF Suez	Liquid	0	0	0	0	0	0	0	0	0	0
18	LNG From Storage		729	321	326	157	178	228	233	220	208	222
19	Other Purchased Resource	Valley	0	0	0	0	0	0	0	0	0	0
		Providence	0	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		24,135	24,281	24,898	24,434	24,459	24,241	24,404	24,359	24,249	24,521

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NON-HEATING SEASON (Apr-Oct)

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	1,939	1,948	1,950	1,932	1,937	1,945	1,949	1,936	1,956	1,955
		Providence	7,578	7,613	7,622	7,549	7,568	7,602	7,617	7,568	7,645	7,642
		Warren	192	192	193	191	191	192	193	191	193	193
		Westerly	160	161	161	159	160	160	161	160	161	161
2	Fuel Reimbursement		380	432	379	371	372	373	377	373	375	371
3	Storage Refill		4,205	4,411	3,851	3,662	3,701	3,747	3,800	3,748	3,755	3,690
4	TOTAL		14,452	14,756	14,156	13,864	13,928	14,020	14,095	13,975	14,085	14,012
	RESOURCES											
5	TGP	Dawn	8	38	27	26	26	26	26	26	26	26
6		Niagara	144	193	231	231	231	231	231	231	231	231
7		Gulf Coast	2,420	2,442	2,272	2,228	2,232	2,236	2,273	2,239	2,253	2,205
8		Dracut	521	541	659	672	674	679	681	675	681	676
9		Storage	185	183	96	94	111	108	100	96	117	98
10	TET/AGT	TET Long-Haul	1,909	2,421	1,918	1,909	1,909	1,909	1,920	1,910	1,910	1,907
11		TCO	297	351	353	230	230	236	259	248	252	238
12		Transco	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	0	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	1,526	1,527	1,528	1,529	1,527	1,529	1,529
15		M3	7,959	7,999	8,007	6,523	6,542	6,571	6,574	6,534	6,610	6,610
16		Storage	13	0	0	1	1	1	3	1	1	1
17	GDF Suez	Liquid	863	455	460	291	312	362	366	354	342	356
18	LNG From Storage		134	134	134	134	134	134	134	134	134	134
19	Other Purchased Resource	Valley	0	0	0	0	0	0	0	0	0	0
		Providence	0	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		14,452	14,757	14,156	13,864	13,928	14,020	14,096	13,975	14,086	14,012

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			ANNUAL								
			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	6,500	6,530	6,660	6,552	6,562	6,529	6,563	6,543	6,542	6,594
		Providence	25,404	25,521	26,026	25,608	25,646	25,516	25,650	25,572	25,565	25,769
		Warren	642	645	658	647	648	645	648	646	646	651
		Westerly	536	538	549	540	541	538	541	539	539	543
2	Fuel Reimbursement		1,301	1,391	1,311	1,288	1,289	1,285	1,298	1,286	1,287	1,287
3	Storage Refill		4,205	4,411	3,851	3,662	3,701	3,747	3,800	3,748	3,755	3,690
4	TOTAL		38,588	39,037	39,054	38,297	38,387	38,260	38,499	38,334	38,334	38,533
	RESOURCES											
5	TGP	Dawn	101	115	152	145	149	152	153	153	152	154
6		Niagara	281	355	395	394	394	394	395	394	394	394
7		Gulf Coast	7,580	7,934	7,355	7,242	7,257	7,196	7,294	7,206	7,210	7,191
8		Dracut	645	627	827	785	774	784	789	790	787	805
9		Storage	1,409	1,557	1,451	1,437	1,455	1,451	1,428	1,448	1,468	1,450
					0	0	0	0	0	0	0	0
10	TET/AGT	TET Long-Haul	6,177	6,880	6,429	6,365	6,366	6,363	6,424	6,366	6,365	6,363
11		TCO	5,508	6,454	5,766	5,356	5,331	5,321	5,381	5,332	5,330	5,353
12		Transco	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	67	72	93	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	2,569	2,608	2,577	2,601	2,603	2,594	2,611
15		M3	13,148	11,733	13,726	11,489	11,496	11,365	11,359	11,398	11,397	11,555
16		Storage	1,933	2,400	1,941	1,935	1,934	1,934	1,943	1,936	1,955	1,946
17	GDF Suez	Liquid	863	455	460	291	312	362	366	354	342	356
18	LNG From Storage		863	455	460	291	312	362	367	355	342	356
19	Other Purchased Resource	Valley	0	0	0	0	0	0	0	0	0	0
		Providence	0	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		38,588	39,037	39,054	38,298	38,387	38,261	38,499	38,335	38,335	38,533

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HEATING SEASON (Nov-Mar)

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	5,104	5,184	5,386	5,332	5,391	5,396	5,492	5,532	5,561	5,681
		Providence	20,281	20,597	21,401	21,188	21,422	21,441	21,822	21,981	22,097	22,574
		Warren	513	520	541	535	541	542	552	556	559	570
		Westerly	425	432	448	444	449	449	457	461	463	473
2	Fuel Reimbursement		959	989	966	959	963	960	972	965	968	973
3	Storage Refill		0	0	0	0	0	0	0	0	0	0
4	TOTAL		27,282	27,721	28,742	28,458	28,767	28,787	29,294	29,494	29,647	30,271
	RESOURCES											
5	TGP	Dawn	105	98	137	136	137	137	138	139	139	140
6		Niagara	145	163	164	163	163	163	164	163	163	163
7		Gulf Coast	5,444	5,550	5,288	5,280	5,330	5,275	5,360	5,307	5,317	5,347
8		Dracut	854	847	1,048	957	977	995	1,041	1,083	1,091	1,150
9		Storage	1,263	1,374	1,355	1,357	1,330	1,352	1,330	1,356	1,360	1,371
10	TET/AGT	TET Long-Haul	4,241	4,462	4,509	4,457	4,462	4,462	4,511	4,462	4,462	4,462
11		TCO	5,687	6,504	5,870	5,733	5,777	5,716	5,788	5,796	5,843	5,958
12		Transco	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	510	580	734	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	1,380	1,451	1,441	1,480	1,505	1,510	1,544
15		M3	5,947	4,599	6,135	5,714	5,750	5,726	5,781	5,828	5,827	5,902
16		Storage	1,930	2,400	1,941	1,934	1,934	1,934	1,941	1,936	1,954	1,945
17	GDF Suez	Liquid	0	0	0	0	0	0	0	0	0	0
18	LNG From Storage		849	849	849	849	849	849	848	849	849	849
19	Other Purchased Resource	Valley	184	187	279	234	255	283	320	355	368	432
		Providence	109	111	433	264	352	457	591	718	765	1,010
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		27,281	27,722	28,742	28,458	28,767	28,787	29,295	29,494	29,647	30,272

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NON-HEATING SEASON (Apr-Oct)

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	2,171	2,203	2,228	2,229	2,257	2,290	2,317	2,325	2,372	2,395
		Providence	8,629	8,755	8,853	8,857	8,968	9,099	9,208	9,239	9,427	9,516
		Warren	218	221	224	224	227	230	233	233	238	240
		Westerly	181	184	186	186	188	191	193	194	198	200
2	Fuel Reimbursement		406	457	401	394	395	399	405	403	407	406
3	Storage Refill		4,360	4,938	4,421	4,407	4,393	4,434	4,479	4,447	4,479	4,421
4	TOTAL		15,965	16,759	16,313	16,296	16,427	16,642	16,834	16,840	17,121	17,178
	RESOURCES											
5	TGP	Dawn	8	41	44	46	47	49	50	51	62	69
6		Niagara	150	215	231	231	231	231	231	231	231	231
7		Gulf Coast	2,714	2,672	2,366	2,336	2,321	2,362	2,407	2,382	2,410	2,384
8		Dracut	541	552	831	862	876	890	901	908	923	926
9		Storage	181	179	141	132	144	160	160	160	188	180
10	TET/AGT	TET Long-Haul	1,906	2,421	1,918	1,910	1,910	1,910	1,921	1,911	1,911	1,907
11		TCO	409	498	529	312	327	355	408	403	426	421
12		Transco	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	0	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	1,561	1,564	1,568	1,572	1,573	1,578	1,581
15		M3	8,937	9,062	9,135	7,789	7,888	7,995	8,064	8,103	8,272	8,359
16		Storage	3	4	2	1	3	5	4	4	4	4
17	GDF Suez	Liquid	983	983	983	983	983	983	983	983	983	983
18	LNG From Storage		134	134	134	134	134	134	134	134	134	134
19	Other Purchased Resource	Valley	0	0	0	0	0	0	0	0	0	0
		Providence	0	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		15,966	16,759	16,313	16,296	16,427	16,642	16,834	16,841	17,121	17,179

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ANNUAL

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	7,275	7,387	7,614	7,561	7,648	7,686	7,809	7,857	7,933	8,076
		Providence	28,910	29,352	30,254	30,044	30,390	30,540	31,030	31,220	31,524	32,090
		Warren	731	742	765	759	768	772	784	789	797	811
		Westerly	606	615	634	630	637	640	650	654	661	673
2	Fuel Reimbursement		1,366	1,446	1,367	1,353	1,358	1,359	1,376	1,368	1,375	1,380
3	Storage Refill		4,360	4,938	4,421	4,407	4,393	4,434	4,479	4,447	4,479	4,421
4	TOTAL		43,247	44,480	45,055	44,754	45,193	45,430	46,128	46,334	46,768	47,449
	RESOURCES											
5	TGP	Dawn	114	139	182	183	184	186	188	190	201	209
6		Niagara	295	378	395	394	394	394	395	394	394	394
7		Gulf Coast	8,158	8,222	7,654	7,616	7,651	7,637	7,767	7,689	7,727	7,731
8		Dracut	1,395	1,398	1,879	1,819	1,853	1,885	1,941	1,991	2,014	2,076
9		Storage	1,443	1,552	1,495	1,490	1,474	1,513	1,490	1,515	1,548	1,552
					0	0	0	0	0	0	0	0
10	TET/AGT	TET Long-Haul	6,148	6,883	6,427	6,367	6,371	6,371	6,432	6,372	6,372	6,369
11		TCO	6,096	7,002	6,399	6,044	6,104	6,071	6,197	6,199	6,268	6,379
12		Transco	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	510	580	734	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	2,941	3,015	3,009	3,052	3,077	3,089	3,124
15		M3	14,884	13,661	15,270	13,503	13,638	13,720	13,845	13,930	14,099	14,261
16		Storage	1,934	2,404	1,943	1,935	1,937	1,939	1,945	1,940	1,958	1,949
17	GDF Suez	Liquid	983	983	983	983	983	983	983	983	983	983
18	LNG From Storage		983	983	983	983	983	983	983	983	983	983
19	Other Purchased Resource	Valley	184	187	279	234	255	283	320	355	368	432
		Providence	109	111	433	264	352	457	591	718	765	1,010
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		43,247	44,481	45,055	44,754	45,194	45,429	46,129	46,335	46,769	47,450

National Grid Rhode Island
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High Design Year
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High Design Day

			Jan 2014	Jan 2015	Jan 2016	Jan 2017	Jan 2018	Jan 2019	Jan 2020	Jan 2021	Jan 2022	Jan 2023
	REQUIREMENTS											
1	Firm Sendout	Valley	64	66	65	63	66	69	70	70	70	72
		Providence	255	263	258	252	263	275	279	279	280	285
		Warren	6	7	7	6	7	7	7	7	7	7
		Westerly	5	6	5	5	6	6	6	6	6	6
2	Fuel Reimbursement		9	10	9	9	10	10	10	9	9	9
3	Storage Refill		0	0	0	0	0	0	0	0	0	0
4	TOTAL		340	351	344	336	351	367	371	372	372	379
	RESOURCES											
5	TGP	Dawn	1	1	1	1	1	1	1	1	1	1
6		Niagara	1	1	1	1	1	1	1	1	1	1
7		Gulf Coast	43	43	43	43	43	43	43	43	43	43
8		Dracut	15	15	15	15	15	15	15	15	15	15
9		Storage	11	11	11	11	11	11	11	11	11	11
10	TET/AGT	TET Long-Haul	49	50	50	50	50	50	50	50	50	50
11		TCO	48	48	48	48	48	48	48	48	48	48
12		Transco	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	12	12	12	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	15	16	16	16	16	16	17
15		M3	19	16	16	12	26	12	12	12	25	14
16		Storage	25	27	27	28	14	28	28	28	14	26
17	GDF Suez	Liquid	0	0	0	0	0	0	0	0	0	0
18	LNG From Storage		102	100	95	94	100	112	113	113	113	113
19	Other Purchased Resource	Valley	14	26	25	18	26	29	30	30	30	32
		Providence	0	0	0	0	0	0	3	3	4	9
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		340	351	344	336	351	367	371	372	372	379

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HEATING SEASON (Nov-Mar)

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	4,607	4,674	4,851	4,808	4,861	4,866	4,947	4,988	5,015	5,123
		Providence	18,005	18,268	18,959	18,792	19,000	19,017	19,333	19,495	19,599	20,021
		Warren	455	462	479	475	480	481	489	493	495	506
		Westerly	380	385	400	396	401	401	408	411	413	422
2	Fuel Reimbursement		926	965	942	931	935	932	945	941	943	950
3	Storage Refill		0	0	0	0	0	0	0	0	0	0
4	TOTAL		24,373	24,754	25,631	25,402	25,677	25,696	26,121	26,328	26,465	27,022
	RESOURCES											
5	TGP	Dawn	95	87	132	127	132	132	134	134	134	136
6		Niagara	138	163	164	163	163	163	164	163	163	163
7		Gulf Coast	5,186	5,524	5,157	5,117	5,142	5,103	5,189	5,154	5,171	5,218
8		Dracut	145	130	260	214	230	263	300	346	358	403
9		Storage	1,232	1,373	1,355	1,347	1,349	1,345	1,328	1,352	1,352	1,355
10	TET/AGT	TET Long-Haul	4,297	4,460	4,511	4,460	4,462	4,460	4,511	4,462	4,462	4,462
11		TCO	5,238	6,148	5,523	5,279	5,278	5,255	5,330	5,349	5,384	5,493
12		Transco	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	73	84	138	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	1,133	1,182	1,164	1,203	1,235	1,245	1,281
15		M3	5,236	4,014	5,968	5,397	5,540	5,503	5,607	5,747	5,761	5,929
16		Storage	1,918	2,400	1,941	1,933	1,933	1,933	1,940	1,936	1,954	1,945
17	GDF Suez	Liquid	0	0	0	0	0	0	0	0	0	0
18	LNG From Storage		802	371	484	234	267	373	416	448	474	603
19	Other Purchased Resource	Valley	0	0	0	0	0	0	0	2	7	35
		Providence	0	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		24,373	24,754	25,631	25,403	25,677	25,696	26,121	26,328	26,465	27,022

National Grid Rhode Island
Comparison of Resources and Requirements
High Normal Year
(BBtu)

NON-HEATING SEASON (Apr-Oct)

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	1,958	1,987	2,009	2,010	2,035	2,065	2,090	2,097	2,139	2,160
		Providence	7,653	7,765	7,852	7,855	7,954	8,070	8,166	8,195	8,361	8,440
		Warren	194	196	198	199	201	204	206	207	211	213
		Westerly	161	164	166	166	168	170	172	173	176	178
2	Fuel Reimbursement		383	436	384	378	380	382	387	385	389	387
3	Storage Refill		4,287	4,466	4,018	3,759	3,816	3,917	4,007	4,006	4,057	4,113
4	TOTAL		14,636	15,014	14,627	14,366	14,554	14,807	15,028	15,062	15,333	15,491
	RESOURCES											
5	TGP	Dawn	8	38	29	28	28	30	32	32	34	39
6		Niagara	145	195	231	231	231	231	231	231	231	231
7		Gulf Coast	2,449	2,476	2,298	2,265	2,280	2,289	2,334	2,309	2,334	2,295
8		Dracut	523	544	691	717	730	745	757	763	781	787
9		Storage	189	188	105	107	130	129	125	125	150	136
10	TET/AGT	TET Long-Haul	1,906	2,421	1,918	1,909	1,909	1,909	1,920	1,911	1,911	1,907
11		TCO	307	380	395	263	273	292	328	324	344	341
12		Transco	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	0	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	1,535	1,538	1,541	1,544	1,544	1,549	1,552
15		M3	8,026	8,132	8,209	6,806	6,896	6,998	7,072	7,104	7,256	7,330
16		Storage	13	0	0	4	4	2	2	2	1	1
17	GDF Suez	Liquid	936	505	618	368	401	507	550	583	609	738
18	LNG From Storage		134	134	134	134	134	134	134	134	134	134
19	Other Purchased Resource	Valley	0	0	0	0	0	0	0	0	0	0
		Providence	0	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		14,636	15,014	14,627	14,366	14,554	14,808	15,029	15,062	15,334	15,491

National Grid Rhode Island
Comparison of Resources and Requirements
High Normal Year
(BBtu)

			ANNUAL									
			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	6,565	6,661	6,860	6,818	6,897	6,931	7,037	7,085	7,154	7,282
		Providence	25,658	26,033	26,811	26,647	26,953	27,087	27,499	27,690	27,959	28,461
		Warren	649	658	677	674	681	685	695	700	707	719
		Westerly	541	549	565	562	568	571	580	584	590	600
2	Fuel Reimbursement		1,309	1,401	1,325	1,309	1,315	1,314	1,332	1,326	1,332	1,337
3	Storage Refill		4,287	4,466	4,018	3,759	3,816	3,917	4,007	4,006	4,057	4,113
4	TOTAL		39,009	39,768	40,257	39,768	40,230	40,503	41,149	41,389	41,798	42,512
	RESOURCES											
5	TGP	Dawn	103	125	161	155	160	162	166	166	169	175
6		Niagara	282	358	395	394	394	394	395	394	394	394
7		Gulf Coast	7,636	8,001	7,454	7,382	7,422	7,393	7,523	7,463	7,504	7,513
8		Dracut	667	674	951	930	960	1,008	1,057	1,110	1,139	1,190
9		Storage	1,421	1,561	1,459	1,454	1,479	1,474	1,453	1,476	1,502	1,491
					0	0	0	0	0	0	0	0
10	TET/AGT	TET Long-Haul	6,203	6,882	6,429	6,369	6,371	6,369	6,431	6,372	6,372	6,369
11		TCO	5,545	6,527	5,918	5,542	5,552	5,547	5,658	5,673	5,728	5,834
12		Transco	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	73	84	138	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	2,667	2,720	2,705	2,747	2,779	2,794	2,832
15		M3	13,262	12,146	14,177	12,202	12,436	12,501	12,678	12,851	13,018	13,258
16		Storage	1,931	2,400	1,941	1,937	1,937	1,936	1,942	1,938	1,956	1,946
17	GDF Suez	Liquid	936	505	618	368	401	507	550	583	609	738
18	LNG From Storage		936	506	618	369	401	508	550	583	609	738
19	Other Purchased Resource	Valley	0	0	0	0	0	0	0	2	7	35
		Providence	0	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		39,009	39,768	40,258	39,769	40,231	40,503	41,149	41,389	41,798	42,513

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap Year
(BBtu)

HEATING SEASON (Nov-Mar)

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	4,735	4,756	4,882	4,793	4,799	4,758	4,789	4,780	4,757	4,810
		Providence	18,507	18,586	19,081	18,734	18,756	18,597	18,716	18,679	18,592	18,799
		Warren	468	470	482	474	474	470	473	472	470	475
		Westerly	390	392	402	395	395	392	395	394	392	396
2	Fuel Reimbursement		925	961	934	919	919	913	922	914	913	917
3	Storage Refill		0	0	0	0	0	0	0	0	0	0
4	TOTAL		25,025	25,165	25,782	25,315	25,342	25,130	25,294	25,239	25,125	25,397
	RESOURCES											
5	TGP	Dawn	93	78	125	120	124	126	127	127	126	128
6		Niagara	137	163	164	163	163	163	164	163	163	163
7		Gulf Coast	5,161	5,492	5,083	5,014	5,025	4,960	5,021	4,967	4,957	4,985
8		Dracut	298	181	243	201	171	207	217	203	176	215
9		Storage	1,223	1,374	1,355	1,344	1,344	1,344	1,328	1,352	1,352	1,351
10	TET/AGT	TET Long-Haul	4,268	4,458	4,511	4,456	4,457	4,454	4,504	4,457	4,455	4,456
11		TCO	5,214	6,103	5,416	5,187	5,136	5,096	5,132	5,098	5,098	5,129
12		Transco	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	193	199	258	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	1,080	1,115	1,081	1,104	1,107	1,097	1,114
15		M3	5,469	3,749	5,734	4,984	4,955	4,794	4,785	4,864	4,787	4,945
16		Storage	1,920	2,400	1,941	1,933	1,933	1,933	1,940	1,935	1,953	1,945
17	GDF Suez	Liquid	0	0	0	0	0	0	0	0	0	0
18	LNG From Storage		849	849	849	749	819	849	849	849	849	849
19	Other Purchased Resource	Valley	151	119	102	84	103	123	125	119	113	118
		Providence	35	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	3	2	1	0	0	0	0	0	0	0
20	TOTAL		25,025	25,165	25,782	25,315	25,343	25,130	25,294	25,240	25,125	25,397

National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap Year
(BBtu)

NON-HEATING SEASON (Apr-Oct)

			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	1,939	1,948	1,950	1,932	1,937	1,945	1,949	1,936	1,956	1,955
		Providence	7,578	7,613	7,622	7,549	7,568	7,602	7,617	7,568	7,645	7,642
		Warren	192	192	193	191	191	192	193	191	193	193
		Westerly	160	161	161	159	160	160	161	160	161	161
2	Fuel Reimbursement		380	432	379	371	372	373	377	373	375	371
3	Storage Refill		4,324	4,939	4,374	4,254	4,342	4,368	4,416	4,376	4,396	4,316
4	TOTAL		14,572	15,284	14,679	14,456	14,569	14,641	14,711	14,604	14,726	14,638
	RESOURCES											
5	TGP	Dawn	8	38	27	26	26	26	26	26	26	26
6		Niagara	144	193	231	231	231	231	231	231	231	231
7		Gulf Coast	2,420	2,442	2,272	2,228	2,232	2,236	2,273	2,239	2,253	2,205
8		Dracut	521	541	659	672	674	679	681	675	681	676
9		Storage	185	183	96	94	111	108	100	96	117	98
10	TET/AGT	TET Long-Haul	1,909	2,421	1,918	1,909	1,909	1,909	1,920	1,910	1,910	1,907
11		TCO	297	351	353	230	230	236	259	248	252	238
12		Transco	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	0	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	1,526	1,527	1,528	1,529	1,527	1,529	1,529
15		M3	7,959	7,999	8,007	6,523	6,542	6,571	6,574	6,534	6,610	6,610
16		Storage	13	0	0	1	1	1	3	1	1	1
17	GDF Suez	Liquid	983	983	983	883	953	983	983	983	983	983
18	LNG From Storage		134	134	134	134	134	134	134	134	134	134
19	Other Purchased Resource	Valley	0	0	0	0	0	0	0	0	0	0
		Providence	0	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	0	0	0	0	0	0	0	0	0	0
20	TOTAL		14,572	15,284	14,679	14,456	14,569	14,641	14,712	14,604	14,727	14,639

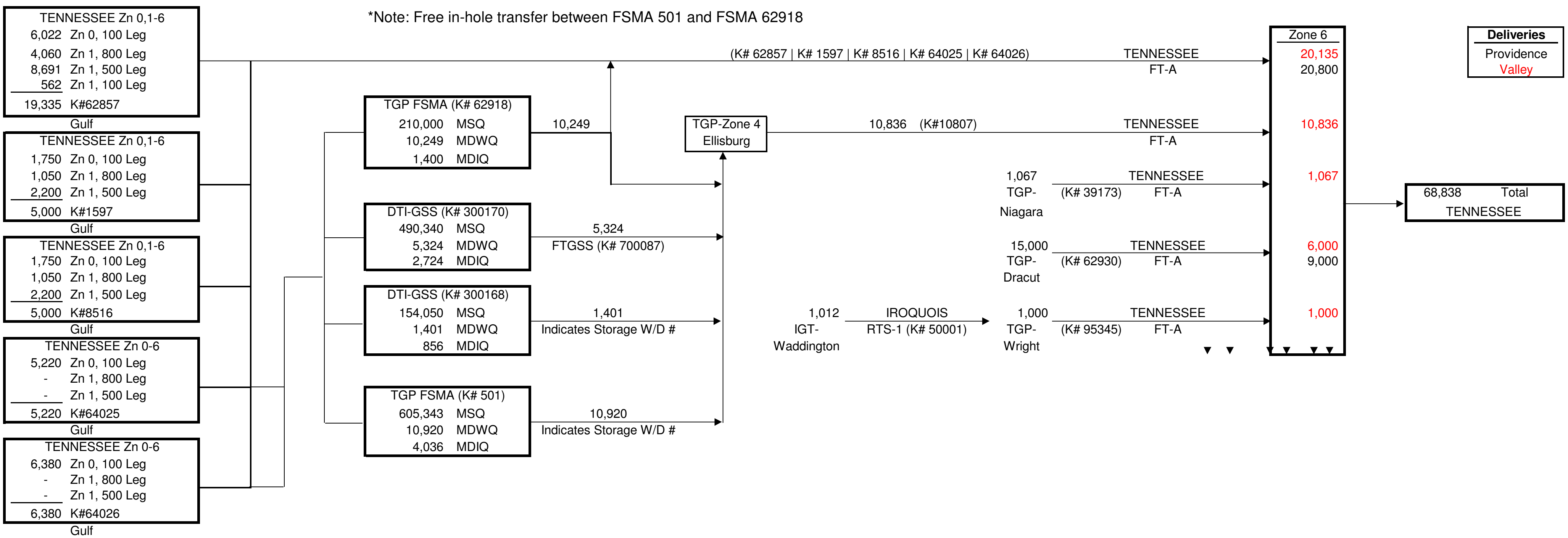
National Grid Rhode Island
Comparison of Resources and Requirements
Cold Snap Year
(BBtu)

			ANNUAL									
			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
	REQUIREMENTS											
1	Firm Sendout	Valley	6,674	6,704	6,833	6,725	6,735	6,704	6,738	6,716	6,713	6,765
		Providence	26,084	26,199	26,703	26,283	26,323	26,199	26,333	26,247	26,237	26,440
		Warren	659	662	675	664	665	662	666	663	663	668
		Westerly	550	552	563	554	555	552	555	553	553	557
2	Fuel Reimbursement		1,306	1,393	1,313	1,291	1,291	1,286	1,299	1,287	1,288	1,288
3	Storage Refill		4,324	4,939	4,374	4,254	4,342	4,368	4,416	4,376	4,396	4,316
4	TOTAL		39,597	40,449	40,461	39,771	39,911	39,771	40,006	39,842	39,851	40,035
	RESOURCES											
5	TGP	Dawn	101	115	152	145	149	152	153	153	152	154
6		Niagara	281	355	395	394	394	394	395	394	394	394
7		Gulf Coast	7,580	7,934	7,355	7,242	7,257	7,196	7,294	7,206	7,210	7,191
8		Dracut	818	722	902	873	845	886	897	877	857	891
9		Storage	1,409	1,557	1,451	1,437	1,455	1,451	1,428	1,448	1,468	1,450
					0	0	0	0	0	0	0	0
10	TET/AGT	TET Long-Haul	6,177	6,880	6,429	6,365	6,366	6,363	6,424	6,366	6,365	6,363
11		TCO	5,511	6,454	5,768	5,417	5,366	5,332	5,391	5,346	5,351	5,367
12		Transco	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13		HubLine	193	199	258	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14		AIM	N/A	N/A	N/A	2,607	2,641	2,609	2,633	2,634	2,626	2,642
15		M3	13,428	11,748	13,741	11,507	11,496	11,365	11,359	11,398	11,397	11,555
16		Storage	1,933	2,400	1,941	1,935	1,934	1,934	1,943	1,936	1,955	1,946
17	GDF Suez	Liquid	983	983	983	883	953	983	983	983	983	983
18	LNG From Storage		983	983	983	883	953	983	983	983	983	983
19	Other Purchased Resource	Valley	151	119	102	84	103	123	125	119	113	118
		Providence	35	0	0	0	0	0	0	0	0	0
		Warren	0	0	0	0	0	0	0	0	0	0
		Westerly	3	2	1	0	0	0	0	0	0	0
20	TOTAL		39,597	40,449	40,461	39,771	39,912	39,771	40,006	39,843	39,852	40,035

RHODE ISLAND COMPANIES - TENNESSEE GAS PIPELINE
PORTFOLIO SCHEMATIC

Peak Season Volumes

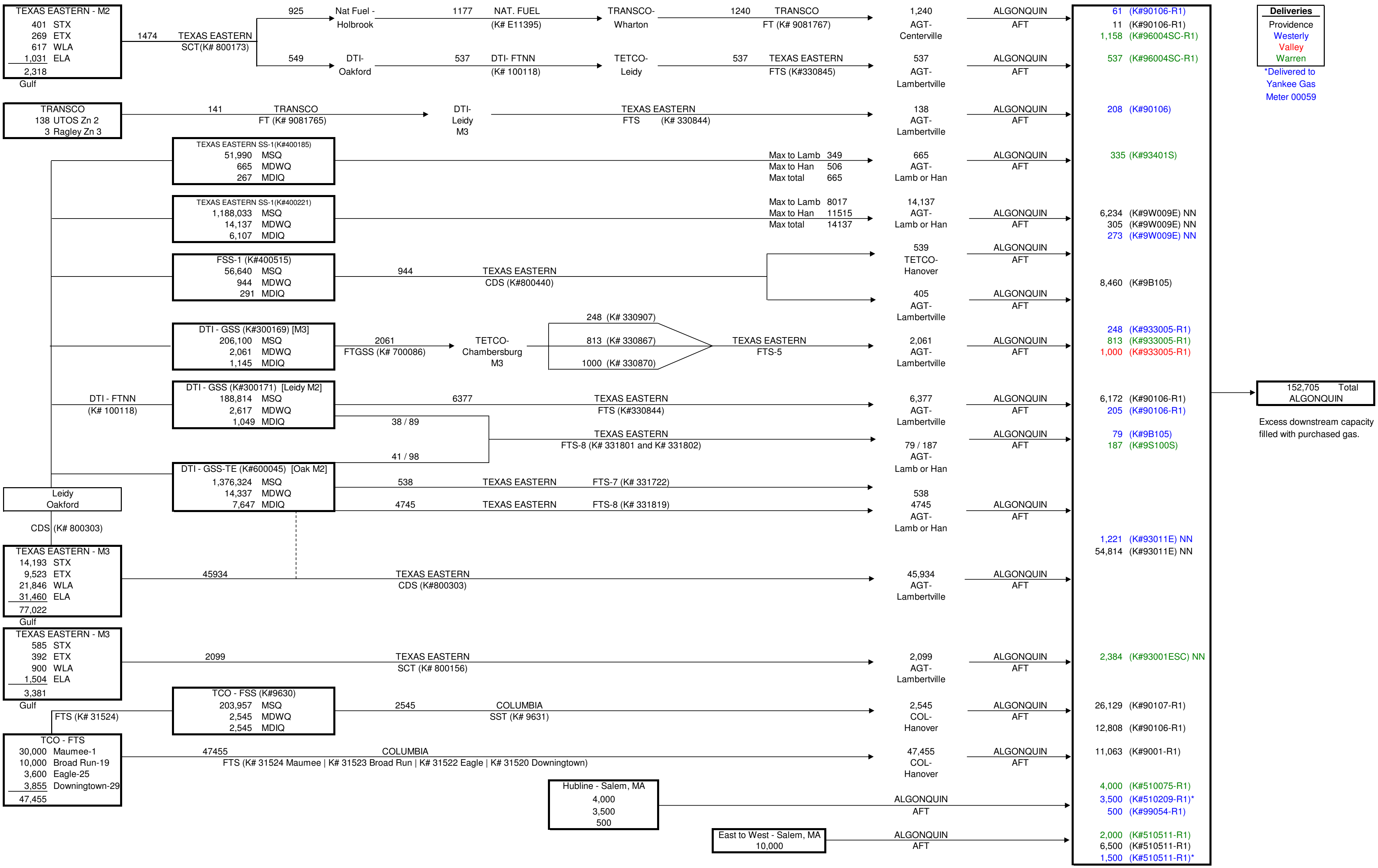
As of November 1, 2013

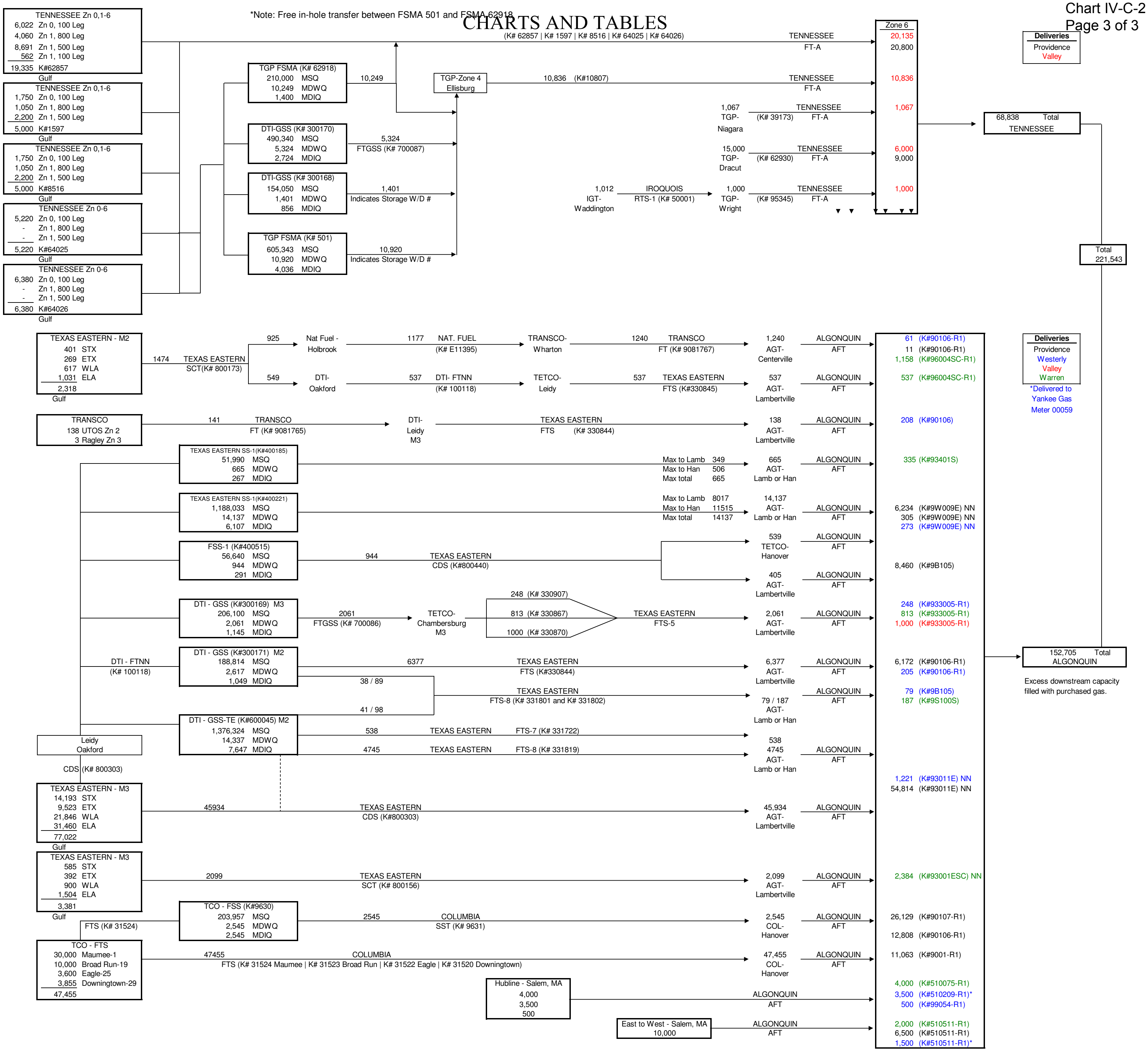


RHODE ISLAND COMPANIES - ALGONQUIN GAS TRANSMISSION
PORTFOLIO SCHEMATIC

Peak Season Volumes

As of November 1, 2013




*Note: Free in-hole transfer between FSMA 501 and FSMA 62918
TENNESSEE Zn 0,1-6
6,022 Zn 0, 100 Leg
4,060 Zn 1, 800 Leg
8,691 Zn 1, 500 Leg
562 Zn 1, 100 Leg
19,335 K#62857
Gulf
TENNESSEE Zn 0,1-6
1,750 Zn 0, 100 Leg
1,050 Zn 1, 800 Leg
2,200 Zn 1, 500 Leg
5,000 K#1597
Gulf
TENNESSEE Zn 0,1-6
1,750 Zn 0, 100 Leg
1,050 Zn 1, 800 Leg
2,200 Zn 1, 500 Leg
5,000 K#8516
Gulf
TENNESSEE Zn 0-6
5,220 Zn 0, 100 Leg
- Zn 1, 800 Leg
- Zn 1, 500 Leg
5,220 K#64025
Gulf
TENNESSEE Zn 0-6
6,380 Zn 0, 100 Leg
- Zn 1, 800 Leg
- Zn 1, 500 Leg
6,380 K#64026
Gulf
(K# 62857 | K# 1597 | K# 8516 | K# 64025 | K# 64026)
TENNESSEE
FT-A
TGP FSMA (K# 62918)
210,000 MSQ
10,249 MDWQ
1,400 MDIQ
10,249
TGP-Zone 4
Ellisburg
10,836 (K#10807)
TENNESSEE
FT-A
DTI-GSS (K# 300170)
490,340 MSQ
5,324 MDWQ
2,724 MDIQ
5,324
FTGSS (K# 700087)
DTI-GSS (K# 300168)
154,050 MSQ
1,401 MDWQ
856 MDIQ
1,401
Indicates Storage W/D #
TGP FSMA (K# 501)
605,343 MSQ
10,920 MDWQ
4,036 MDIQ
10,920
Indicates Storage W/D #
1,067
TGP-
Niagara
TENNESSEE
(K# 39173) FT-A
15,000
TGP-
Dracut
TENNESSEE
(K# 62930) FT-A
1,012
IGT-
Waddington
IROQUOIS
RTS-1 (K# 50001)
1,000
TGP-
Wright
TENNESSEE
(K# 95345) FT-A
Zone 6
20,135
20,800
10,836
1,067
6,000
9,000
1,000
Deliveries
Providence
Valley
68,838 Total
TENNESSEE
Total
221,543
TEXAS EASTERN - M2
401 STX
269 ETX
617 WLA
1,031 ELA
2,318
Gulf
1474
TEXAS EASTERN
SCT(K# 800173)
925
Nat Fuel -
Holbrook
1177
NAT. FUEL
(K# E11395)
TRANSCO-
Wharton
1240
TRANSCO
FT (K# 9081767)
1,240
AGT-
Centerville
ALGONQUIN
AFT
549
DTI-
Oakford
537
DTI- FTNN
(K# 100118)
TETCO-
Leidy
537
TEXAS EASTERN
FTS (K#330845)
537
AGT-
Lambertville
ALGONQUIN
AFT
TRANSCO
138 UTOS Zn 2
3 Ragley Zn 3
141
TRANSCO
FT (K# 9081765)
DTI-
Leidy
M3
TEXAS EASTERN
FTS (K# 330844)
138
AGT-
Lambertville
ALGONQUIN
AFT
TEXAS EASTERN SS-1(K#400185)
51,990 MSQ
665 MDWQ
267 MDIQ
Max to Lamb 349
Max to Han 506
Max total 665
665
AGT-
Lamb or Han
ALGONQUIN
AFT
TEXAS EASTERN SS-1(K#400221)
1,188,033 MSQ
14,137 MDWQ
6,107 MDIQ
Max to Lamb 8017
Max to Han 11515
Max total 14137
14,137
AGT-
Lamb or Han
ALGONQUIN
AFT
FSS-1 (K#400515)
56,640 MSQ
944 MDWQ
291 MDIQ
944
TEXAS EASTERN
CDS (K#800440)
539
TETCO-
Hanover
ALGONQUIN
AFT
405
AGT-
Lambertville
ALGONQUIN
AFT
DTI - GSS (K#300169) M3
206,100 MSQ
2,061 MDWQ
1,145 MDIQ
2061
FTGSS (K# 700086)
TETCO-
Chambersburg
M3
248 (K# 330907)
813 (K# 330867)
1000 (K# 330870)
TEXAS EASTERN
FTS-5
2,061
AGT-
Lambertville
ALGONQUIN
AFT
DTI - FTNN
(K# 100118)
DTI - GSS (K#300171) M2
188,814 MSQ
2,617 MDWQ
1,049 MDIQ
6377
TEXAS EASTERN
FTS (K#330844)
6,377
AGT-
Lambertville
ALGONQUIN
AFT
38 / 89
41 / 98
TEXAS EASTERN
FTS-8 (K# 331801 and K# 331802)
79 / 187
AGT-
Lamb or Han
ALGONQUIN
AFT
DTI - GSS-TE (K#600045) M2
1,376,324 MSQ
14,337 MDWQ
7,647 MDIQ
538
TEXAS EASTERN FTS-7 (K# 331722)
4745
TEXAS EASTERN FTS-8 (K# 331819)
538
4745
AGT-
Lamb or Han
ALGONQUIN
AFT
Leidy
Oakford
CDS (K# 800303)
TEXAS EASTERN - M3
14,193 STX
9,523 ETX
21,846 WLA
31,460 ELA
77,022
Gulf
45934
TEXAS EASTERN
CDS (K#800303)
45,934
AGT-
Lambertville
ALGONQUIN
AFT
TEXAS EASTERN - M3
585 STX
392 ETX
900 WLA
1,504 ELA
3,381
Gulf
2099
TEXAS EASTERN
SCT (K# 800156)
2,099
AGT-
Lambertville
ALGONQUIN
AFT
TCO - FSS (K#9630)
203,957 MSQ
2,545 MDWQ
2,545 MDIQ
FTS (K# 31524)
2545
COLUMBIA
SST (K# 9631)
2,545
COL-
Hanover
ALGONQUIN
AFT
TCO - FTS
30,000 Maumee-1
10,000 Broad Run-19
3,600 Eagle-25
3,855 Downingtown-29
47,455
47455
COLUMBIA
FTS (K# 31524 Maumee | K# 31523 Broad Run | K# 31522 Eagle | K# 31520 Downingtown)
47,455
COL-
Hanover
ALGONQUIN
AFT
Hubline - Salem, MA
4,000
3,500
500
ALGONQUIN
AFT
East to West - Salem, MA
10,000
ALGONQUIN
AFT
61 (K#90106-R1)
11 (K#90106-R1)
1,158 (K#96004SC-R1)
537 (K#96004SC-R1)
208 (K#90106)
335 (K#93401S)
6,234 (K#9W009E) NN
305 (K#9W009E) NN
273 (K#9W009E) NN
8,460 (K#9B105)
248 (K#933005-R1)
813 (K#933005-R1)
1,000 (K#933005-R1)
6,172 (K#90106-R1)
205 (K#90106-R1)
79 (K#9B105)
187 (K#9S100S)
1,221 (K#93011E) NN
54,814 (K#93011E) NN
2,384 (K#93001ESC) NN
26,129 (K#90107-R1)
12,808 (K#90106-R1)
11,063 (K#9001-R1)
4,000 (K#510075-R1)
3,500 (K#510209-R1)*
500 (K#99054-R1)
2,000 (K#510511-R1)
6,500 (K#510511-R1)
1,500 (K#510511-R1)*
Deliveries
Providence
Westerly
Valley
Warren
*Delivered to
Yankee Gas
Meter 00059
152,705 Total
ALGONQUIN
Excess downstream capacity
filled with purchased gas.

NATIONAL GRID - RHODE ISLAND ASSETS
Transportation Contracts

Legacy LDC	Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Notes
PG	Narragansett Electric	Algonquin	9001	AFT1FT3	11,063	4,037,995	12/14/2015	Part-284 transportation service (365-day) used to transport gas from the Columbia interconnect at Hanover, NJ (11,063 MMBtu) to National Grid - Dey St (11,063 MMBtu).
PG	Narragansett Electric	Algonquin	90106	AFT-14	19,465	7,104,725	10/31/2016	Part-284 transportation service (365-day) used to transport gas from the Columbia interconnect at Hanover, NJ (12,808 MMBtu), TETCO interconnect at Lamberville (6,585 MMBtu) and Transco interconnect at Centerville (72 MMBtu) to National Grid - Dey St (9,223 MMBtu), National Grid - Tiverton (598 MMBtu), National Grid - Westerly (474 MMBtu), National Grid - E. Providence (4,092 Mmbtu), and National Grid - Portsmouth (5,078 MMBtu).
PG	Narragansett Electric	Algonquin	90107	AFT-1W	26,129	3,945,479	10/31/2016	Part-284 service with a seasonally adjusted MDQ of (26,129 MMBtu), used to transport gas from the Columbia interconnect at Hanover, NJ to National Grid - Dey St (19, 514 MMBtu) and National Grid - E. Providence (6,615 MMBtu).
VG	Narragansett Electric	Algonquin	933005	AFT-1P	2,061	752,265	03/31/2016	Part-284 transportation service (365-day) used to transport gas from the TETCO interconnect at Lamberville, NJ (2,061 MMBtu) to National Grid - Cumberland (1,000 MMBtu), Narragansett Lectric - Westerly (248 MMBtu), and National Grid - Warren (813 MMBtu).
BW	Narragansett Electric	Algonquin	93001ESC	AFT-ES1	2,384	771,904	10/31/2016	Part-284 NO NOTICE service with a seasonally adjusted MDQ of (2,384 MMBtu), used to transport gas from the TETCO interconnect at Lambertville, NJ (1,377 MMBtu) and Hanover, NJ (1,007 MMBtu) to National Grid - Warren (2,384 MMBtu).
PG	Narragansett Electric	Algonquin	93011E	AFT-E1	56,035	19,446,885	10/31/2016	Part-284 NO NOTICE service with a seasonally adjusted MDQ of (56,035 MMBtu), used to transport gas from the TETCO interconnect at Lambertville, NJ (34,668 MMBtu) and Hanover, NJ (21,367 MMBtu) to National Grid - Dey St (25,137 MMBtu), National Grid - Westerly (1,221 MMBtu), National Grid - E. Providence (48,147 MMBtu), National Grid - Warren (4,173 MMBtu), National Grid - Portsmouth (6,504 MMBtu), and National Grid - Tiverton (163 MMBtu).
BW	Narragansett Electric	Algonquin	93401S	AFT-1S4	335	122,275	10/31/2016	Part-284 transportation service (365-day) used to transport gas from the TETCO interconnect at Lambertville, NJ (335 MMBtu) to National Grid - Warren (335 MMBtu).
BW	Narragansett Electric	Algonquin	96004SC	AFT-1S3	1,695	618,675	10/31/2016	Part-284 firm transportation service (365-day) used to transport gas from the TETCO interconnect at Lambertville, NJ (537 MMBtu) and Centerville, NJ (1,158 MMBtu) to National Grid - Warren (1,695 MMBtu).
PG	Narragansett Electric	Algonquin	9B105	AFT-1B	8,539	1,813,145	10/31/2016	Part-284 service with a seasonally adjusted MDQ of (8,539 MMBtu), used to transport gas from the TETCO interconnect at Lambertville, NJ to National Grid - Dey St (4,258 MMBtu), National Grid - Portsmouth (4,202 MMBtu) and National Grid - Westerly (79 MMBtu).

CHARTS AND TABLES

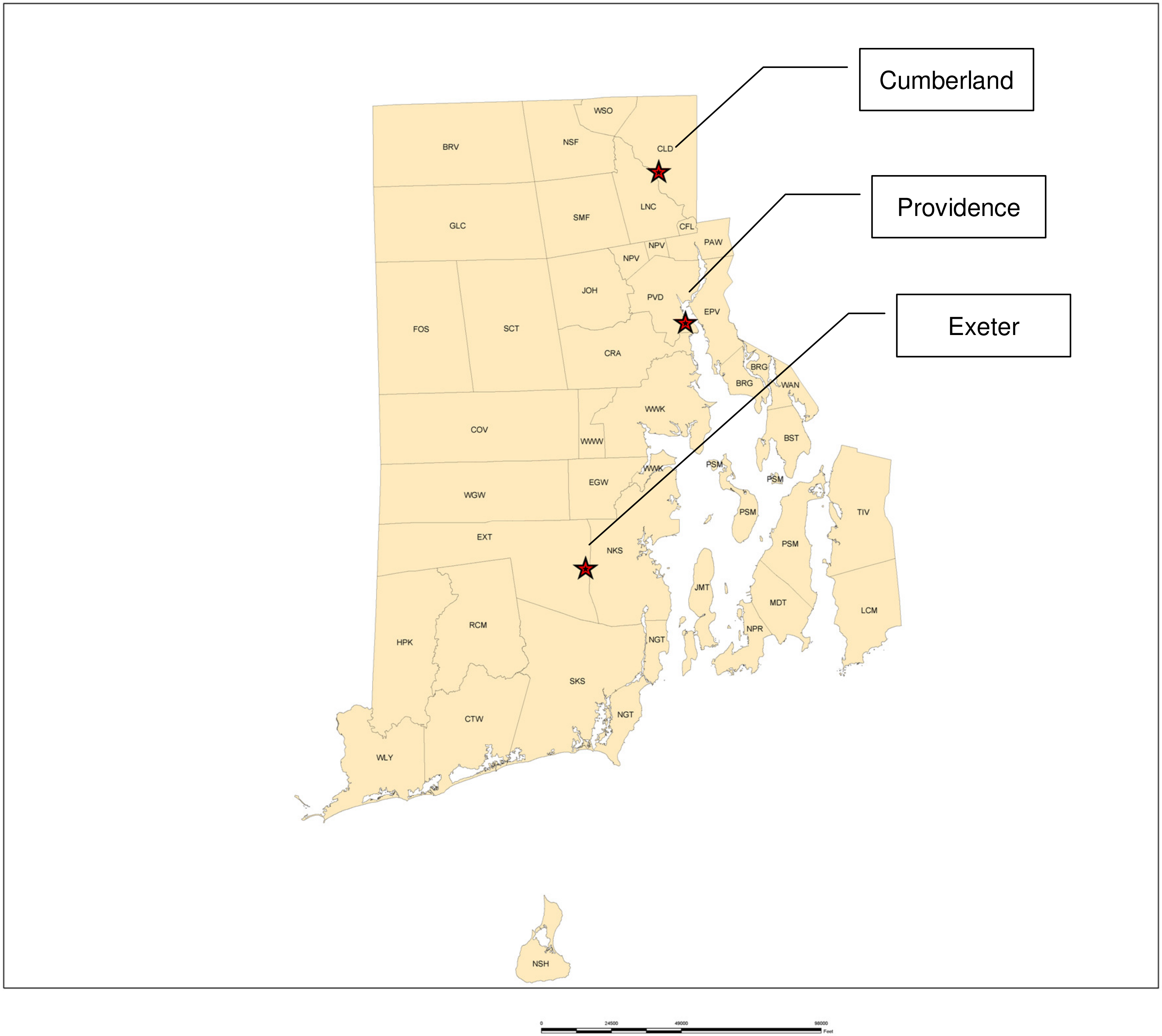
Legacy LDC	Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Notes
BW	Narragansett Electric	Algonquin	9S100S	AFT-1SX	187	39,737	10/31/2016	Part-284 service with a seasonally adjusted MDQ of (187 MMBtu), used to transport gas from the TETCO interconnect at Lambertville, NJ to National Grid - Warren (187 MMBtu).
PG	Narragansett Electric	Algonquin	9W009E	AFT-EW	6,812	1,446,384	10/31/2016	Part-284 NO NOTICE service with a seasonally adjusted MDQ of (6,812 MMBtu), used to transport gas from the TETCO interconnect at Hanover, NJ (4,222 MMBtu) and Lamberville, NJ (2,590 MMBtu) to National Grid - Dey St (6,234 MMBtu), National Grid - Westerly (273 MMBtu), and National Grid - Portsmouth (305 MMBtu).
PG	Narragansett Electric	Algonquin Hubline	99054	AFT1-H	500	182,500	11/30/2023	Part-284 transportation service (365-day) used to transport gas on Hubline at Salem, MA (500 MMBtu) to National Grid - Westerly (500 MMBtu).
BW	Narragansett Electric	Algonquin Hubline	510075	AFT1-H	4,000	1,460,000	11/30/2015	Part-284 transportation service (365-day) used to transport gas on Hubline at Salem, MA (4,000 MMBtu) to National Grid - Warren (4,000 MMBtu).
PG	Narragansett Electric	Algonquin Hubline	510209	AFT1-H	3,500	1,277,500	10/31/2015	Part-284 transportation service (365-day) used to transport gas on Hubline at Salem, MA (3,500 MMBtu) to Montiville (3,500 MMBtu).
NEC	Narragansett Electric	Algonquin Hubline - East to West -	510511	AFT1-H	10,000	3,650,000	10/31/2020	Part-284 transportation service (365-day) used to transport gas on Hubline at Salem, MA (10,000 MMBtu) to National Grid - Warren (2,000 MMBtu), National Grid - Portsmouth (6,000 MMBtu), National Grid - Tiverton (500 MMBtu) and Montiville (1,500 MMBtu).
PG	Narragansett Electric	Columbia	31520	FTS	3,855	1,407,075	10/31/2020	Part-284 transportation service used to transport gas from Downingtown-29 (3,855 MMBtu) to Columbia interconnect at Hanover, NJ (3,855 MMBtu).
PG	Narragansett Electric	Columbia	31522	FTS	3,600	1,314,000	10/31/2020	Part-284 transportation service used to transport gas from Eagle-25 (3,600 MMBtu) to Columbia interconnect at Hanover, NJ (3,600 MMBtu).
PG	Narragansett Electric	Columbia	31523	FTS	10,000	3,650,000	10/31/2020	Part-284 transportation service used to transport gas from Broad Run-19 (10,000 MMBtu) to Columbia interconnect at Hanover, NJ (10,000 MMBtu).
PG	Narragansett Electric	Columbia	31524	FTS	30,000	10,950,000	10/31/2020	Part-284 transportation service used to transport gas from Maumee-1 (30,000 MMBtu) to Columbia interconnect at Hanover, NJ (30,000 MMBtu).
PG	Narragansett Electric	Columbia	9631	SST	2,545	695,966	04/01/2040	Part-284 transportation service used to transport gas from RP Strorage Point TCO-FSS #9630 (2,545 MMBtu) to Columbia interconnect at Hanover, NJ (2,545 MMBtu). MDQ Seasonally adjusted to be 1,272 MDQ from Apr - Sep.
BW	Narragansett Electric	Dominion	100118	FTNN	537	196,005	10/31/2017	Part-284 transportation service used to transport gas from the TETCO interconnect at Oakford (537 MMBtu) to the Leidy Group Meter (537 MMBtu).
RI	Narragansett Electric	Dominion	700086	FTGSS	2,061	311,211	03/31/2017	Transportation contract used to transport gas from DTI-GSS #300169 (2,061MMBtu) to the TETCO interconnect at Chambersburg, PA (2,061 MMBtu).
VG	Narragansett Electric	Dominion	700087	FTGSS	5,324	803,924	03/31/2020	Transportation contract used to transport gas from DTI-GSS #300170 (5,324MMBtu) to Ellisburg, PA (5,324 MMBtu).
VG	Narragansett Electric	Iroquois	50001	RTS-1	1,012	369,380	11/01/2017	Transportation contract used to transport gas from Waddington (1,012 MMBtu) to the IGTS interconnect with TGP at Wright, NY.

Legacy LDC	Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Notes
BW	Narragansett Electric	National Fuel	E11395	EFT	1,177	429,605	03/31/2015	Part-284 transportation service (365-day) used to transport gas from TETCO (907 MMBtu) to Transco - Wharton (907 MMBtu). Storage service from NF Storage to Transco - Wharton (270 MMBtu). (No longer have NF storage).
VG	Narragansett Electric	Tennessee	1597	FT-A	5,000	1,825,000	10/31/2019	Transportation service used to transport gas from Zn1 800 Leg (1,050 MMBtu), Zn1 500 Leg (2,200 MMBtu), and Zn 0 100 Leg (1,750 MMBtu) to National Grid city gates at Pawtucket, RI (5,000 MMBtu).
VG	Narragansett Electric	Tennessee	8516	FT-A	5,000	1,825,000	10/31/2015	Transportation service used to transport gas from Zn1 800 Leg (1,050 MMBtu), Zn1 500 Leg (2,200 MMBtu), and Zn 0 100 Leg (1,750 MMBtu) to National Grid city gates at Pawtucket, RI (5,000 MMBtu).
VG	Narragansett Electric	Tennessee	10807	FT-A	10,836	3,955,140	03/31/2017	Transportation service used to transport gas from Ellisburg (6,581 MMBtu) and Nothern Storage (4,255 MMBtu) to National Grid city gates at Pawtucket, RI (10,836 MMBtu).
VG	Narragansett Electric	Tennessee	39173	FT-A	1,067	389,455	10/31/2019	Transportation service (365-day) used to transport gas from Niagara River (1,067 MMBtu) to National Grid city gates at Pawtucket, RI (1,067 MMBtu).
PG	Narragansett Electric	Tennessee	62857	FT-A	19,335	7,057,275	04/30/2017	Transportation service used to transport gas from Zn1 800 Leg (4,060 MMBtu), Zn1 500 Leg (8,691 MMBtu), Zn0 100 Leg (6,022 MMBtu), and Zn1 100 Leg (562 MMBtu) to National Grid city gates at Pawtucket, RI (4,335 MMBtu), Cranston (10,000 MMBtu), and Smithfield (5,000 MMBtu).
PG	Narragansett Electric	Tennessee	62930	FT-A	15,000	5,475,000	08/31/2017	Transportstion service used to transport gas from the interconnect at Dracut (15,000 MMBtu) to National Grid city gate - Cranston (9,000) and National Grid city gate - Pawtucket, RI (6,000 MMBtu).
NGRI	Narragansett Electric	Tennessee	64025	FT-A	5,220	1,905,300	10/31/2027	TGP ConneXion - Transportation service used to transport gas from Tx Zone 0 (5,220 MMBtu) to National Grid city gates at Lincoln, RI (2,610 MMBtu) and Smithfield, RI (2,610).
NGRI	Narragansett Electric	Tennessee	64026	FT-A	6,380	2,328,700	10/31/2027	TGP ConneXion - Transportation service used to transport gas from Tx Zone 0 (6,380 MMBtu) to National Grid city gates at Lincoln, RI (3,190 MMBtu) and Smithfield, RI (3,190).
VG	Narragansett Electric	Tennessee	95345	FT-A	1,000	365,000	10/31/2017	Transportation service used to transport gas from interconnect at Wright, NY (1,000 MMBtu) to National Grid city gates at Lincoln (1,000 MMBtu).
PG	Narragansett Electric	Texas Eastern	330844	FTS	6,377	2,327,605	10/31/2015	Part-157 (7C) transportation service used to transport gas from Leidy, PA (6,377 MMBtu) to interconnect with AGT at Lambertville, NJ or Hanover, NJ (6,377 MMBtu).
BW	Narragansett Electric	Texas Eastern	330845	FTS	537	196,005	10/31/2015	Part-157 (7C) transportation service used to transport gas from Leidy, PA (537 MMBtu) to interconnect with AGT at Lambertville, NJ or Hanover, NJ (537 MMBtu).
BW	Narragansett Electric	Texas Eastern	330867	FTS-5	813	122,763	03/31/2016	Part-157 (7C) transportation service used to transport gas from Chambersburg, PA (813 MMBtu) to Lambertville, NJ (813 MMBtu). During the period from Apr. 1 to Oct. 31 customer may not tender, without the consent of Pipeline, a daily quantity in excess of the product of the Southern Route Summer Capacity Factor multiplied by 813 dth.
VG	Narragansett Electric	Texas Eastern	330870	FTS-5	1,000	151,000	03/31/2016	Part-157 (7C) transportation service used to transport gas from Chambersburg, PA (1,000 MMBtu) to Lambertville, NJ (1,000 MMBtu). During the period from Apr. 1 to Oct. 31 customer may not tender, without the consent of Pipeline, a daily quantity in excess of the product of the Southern Route Summer Capacity Factor multiplied by 1,000 dth.

CHARTS AND TABLES

Legacy LDC	Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Notes
PG	Narragansett Electric	Texas Eastern	330907	FTS-5	248	37,448	03/31/2016	Part-157 (7C) transportation service used to transport gas from Chambersburg, PA (248 MMBtu) to Lambertville, NJ (248 MMBtu). During the period from Apr. 1 to Oct. 31 customer may not tender, without the consent of Pipeline, a daily quantity in excess of the product of the Southern Route Summer Capacity Factor multiplied by 248 dth.
PG	Narragansett Electric	Texas Eastern	331722	FTS-7	538	196,370	03/31/2016	Part- 157 (7C) transportation service used to transport gas from Oakford, PA (538 MMBtu) to either interconnects at Lambertville or Hanover, NJ (538 MMBtu).
PG	Narragansett Electric	Texas Eastern	331801	FTS-8	79	28,835	03/31/2016	Part-157 (7C) transportation service used to transport gas from Leidy, PA (38 MMBtu) to either interconnects at Lambertville or Hanover, NJ. In addition, Oakford, PA (41 MMBtu) to either interconnects at Lamberville or Hanover, NJ.
BW	Narragansett Electric	Texas Eastern	331802	FTS-8	187	68,255	03/31/2016	Part-157 (7C) transportation service used to transport gas from Leidy, PA (89 MMBtu) to either interconnects at Lambertville or Hanover, NJ. In addition, Oakford, PA (98 MMBtu) to either interconnects at Lamberville or Hanover, NJ.
PG	Narragansett Electric	Texas Eastern	331819	FTS-8	4,745	1,731,925	03/31/2016	Part- 157 (7C) transportation service used to transport gas from Oakford, PA (4,745 MMBtu) to either interconnects at Lambertville or Hanover, NJ (4,745 MMBtu).
BW	Narragansett Electric	Texas Eastern	800156	SCT	2,099	766,135	10/31/2015	Part-284 transportation contract used to transport gas from the access areas at STX (585 MMBtu oper. entitle.), ETX (392 MMBtu oper. entitle.), WLA (900 MMBtu oper. entitle.), and ELA (1,504 MMBtu oper. entitle.) to the TETCO interconnect with AGT at Lambertville, NJ (2,099 MMBtu).
BW	Narragansett Electric	Texas Eastern	800173	SCT	1,474	538,010	10/31/2015	Part-284 transportation contract used to transport gas from the access areas at STX (401 MMBtu oper. entitle.), ETX (269 MMBtu oper. entitle.), WLA (617 MMBtu oper. entitle.), and ELA (1,031 MMBtu oper. entitle.) to the National Fuel interconnect at Holbrook, PA (925 MMBtu) and Oakford, PA (549 MMBtu).
PG	Narragansett Electric	Texas Eastern	800303	CDS	45,934	16,795,910	10/31/2015	Part-284 transportation contract used to transport gas from the access areas at STX (14,193 MMBtu oper. entitle.), ETX (9,523 MMBtu oper. entitle.), WLA (21,846 MMBtu oper. entitle.), and ELA (31,460 MMBtu oper. entitle.) to the TETCO interconnect with AGT at Lambertville, NJ (45,934 MMBtu) or Hanover, NJ (18,656 MMBtu) or Zone M3 Storage Point (6665 MMBtu).
PG	Narragansett Electric	Texas Eastern	800440	CDS	944	344,560	10/31/2015	Part-284 transportation contract used to transport gas from TETCO FSS-1 #400515 to the TETCO interconnects at Lambertville, NJ (405 MMBtu) and Hanover, NJ (539 MMBtu).
NGRI	Narragansett Electric	TransCanada	42386	FT	1,012	369,380	10/31/2016	Transportation service used to transport gas from the Union Gas interconnect at Parkway to the interconnect with Iroquois Gas Transmission at Waddington, NY (1,012 MMBtu).
PG	Narragansett Electric	Transco	9081765	FT	141	51,465	10/30/2014	Part-284 transportation service used to transport gas from the UTOS - TGPL Meter Zn2 (138 MMBtu) to DTI Leidy, PA Zn6 (138 MMBtu). Also, from TETCO interconnect at Ragley Zn3 (3 MMBtu) to DTI Leidy, PA Zn6 (3 MMBtu).
PG	Narragansett Electric	Transco	9081767	FT	1,240	452,600	03/31/2016	Part-284 transportation service used to transport gas from the National Fuel interconnect at Wharton (1,240 MMBtu) to the Algonquin interconnect at Centerville, NJ (1,240 MMBtu).
NGRI	Narragansett Electric	Union Gas	M12164	FT	1,025	374,125	10/31/2020	Transportation service used to transport gas from Dawn, Ontario to the interconnect with TransCanade Pipeline at Parkway (1,025 MMBtu).

Note: If volumes transported to points other than primary points as listed on the contract, maximum commodity rate per TGP's tariff apply.



Rhode Island LNG Facilities

★ LNG Facility

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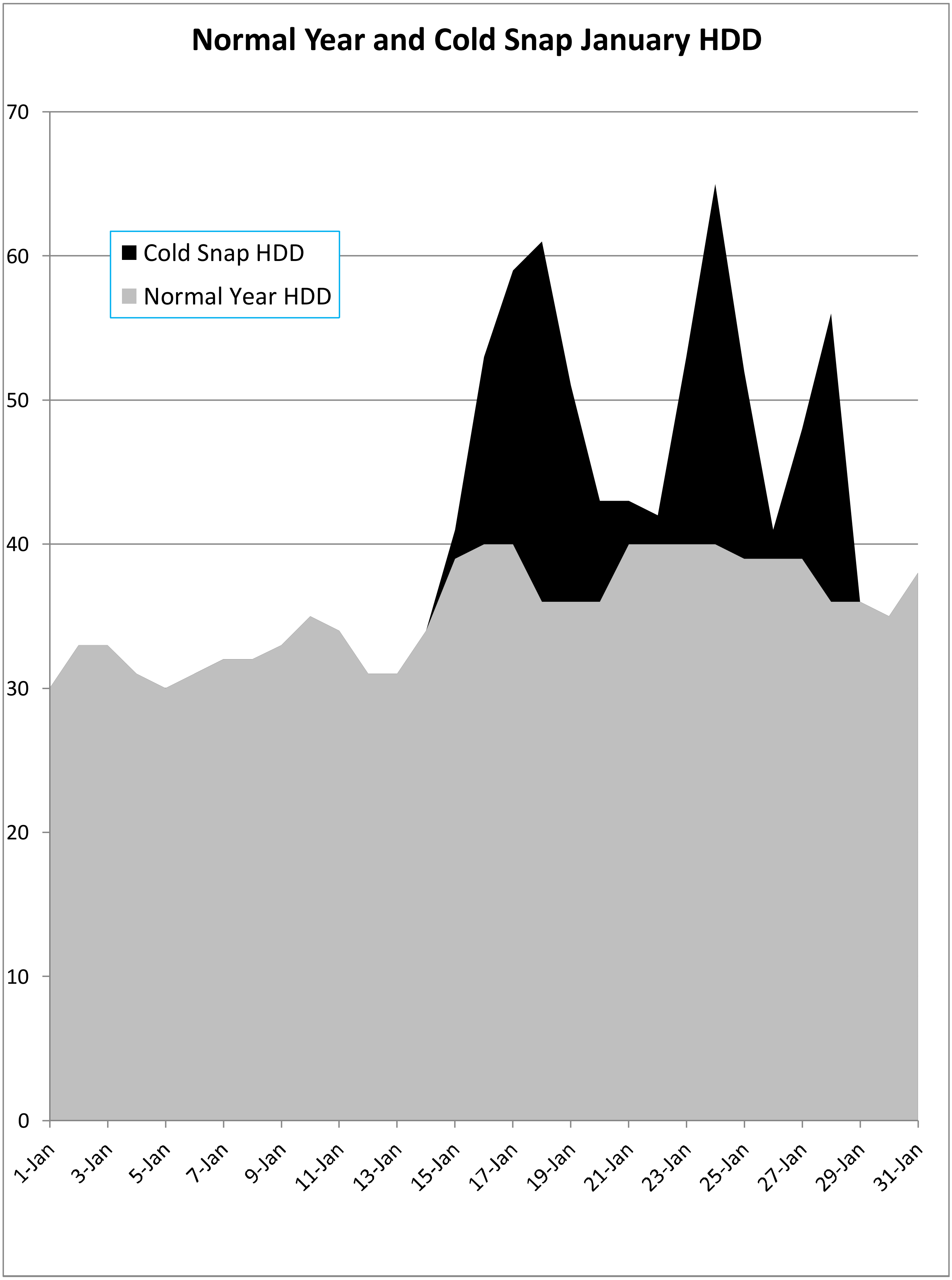
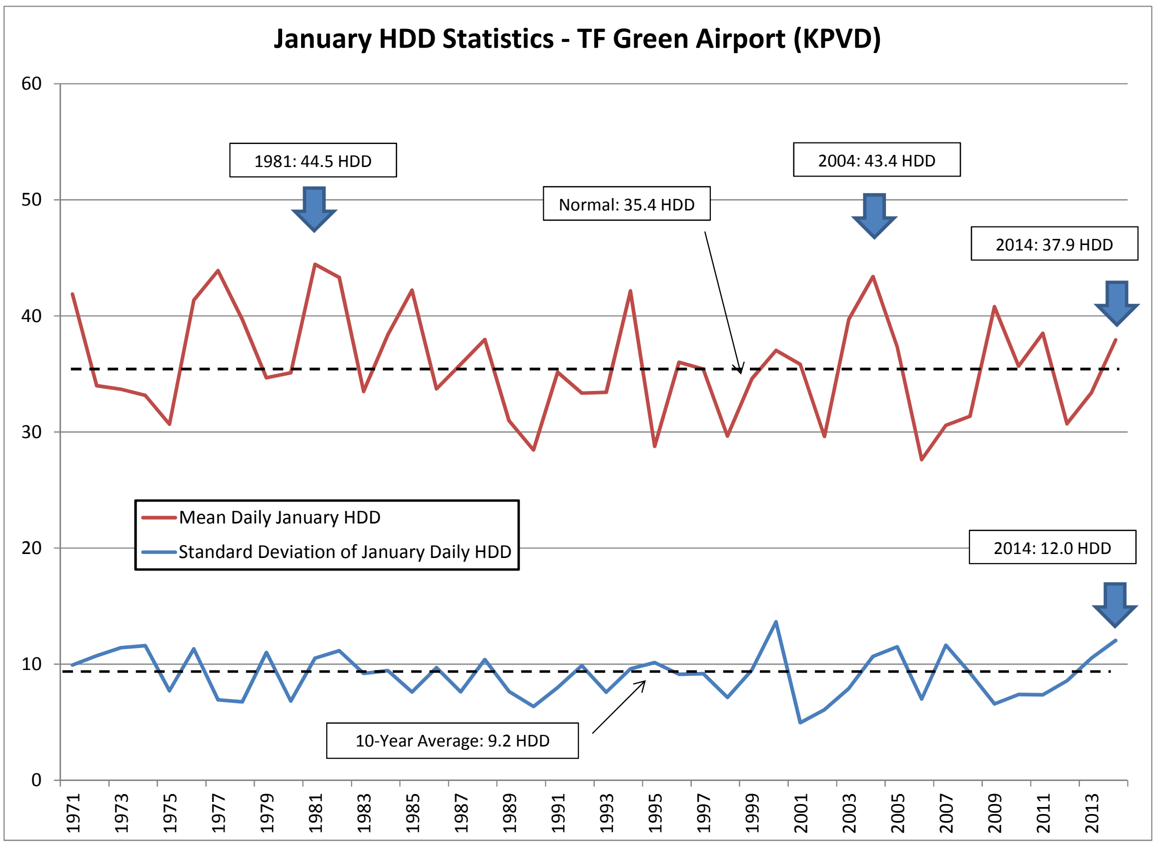

Normal Year and Cold Snap January HDD
Cold Snap HDD
Normal Year HDD
70
60
50
40
30
20
10
0
1-Jan
3-Jan
5-Jan
7-Jan
9-Jan
11-Jan
13-Jan
15-Jan
17-Jan
19-Jan
21-Jan
23-Jan
25-Jan
27-Jan
29-Jan
31-Jan

Appendix A
Misc. Weather
Sendout and
Pricing Info.

Appendix A: Weather and Sendout Information

A. January 2014 Weather Compared to Prior Januarys

The chart below shows the Company's history of January HDD from 1971 - 2014. It shows that Jan 2014 has been colder than normal, but not as cold as either Jan 2004 or Jan 1981 (red line). It also shows that Jan 2014 has had more variability than normal in terms of standard deviation of the daily HDD values. Historically, 2/3rds of the Jan HDD values have been +/- 9.2 HDD of the mean, while in Jan 2014 it has been +/- 12.0 HDD. So, the Company has observed a few 'mild' days in January 2014 and then some cold days. The coldest day in Jan 2014 was 59 HDD; the design day is 68 HDD.



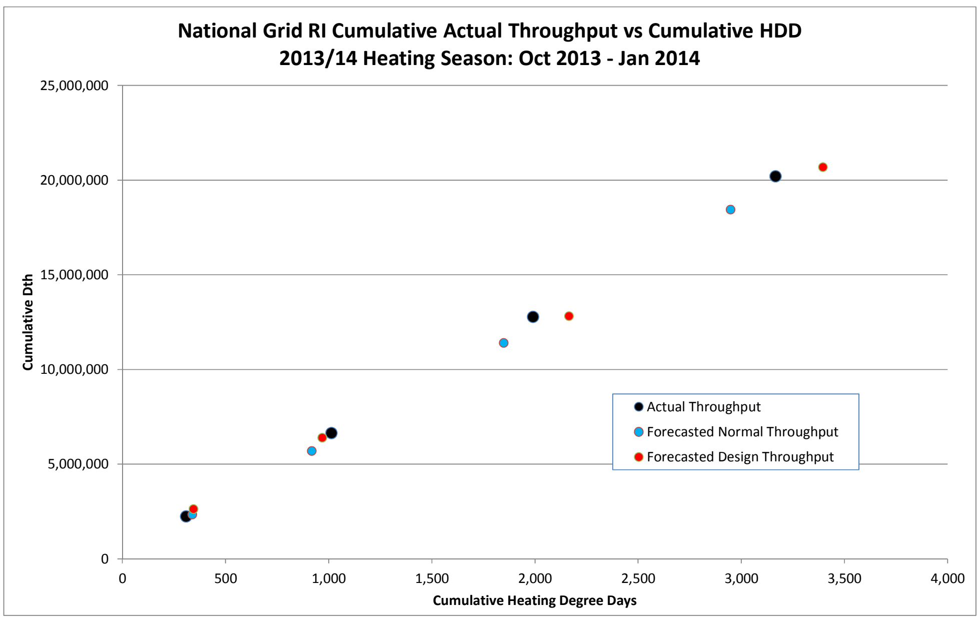
B. January 2014 Weather versus Throughput

The chart below compares the monthly values for HDD and RI total throughput for Oct 2013- Jan 2014 relative to the 2013Q2 forecast for normal and design values. The two sets of numbers highlighted in yellow are the key figures showing that Dec 2013 and Jan 2014 HDD were 105-107 percent of normal and the corresponding throughput figures were also in the range of 105-107 percent of our normal forecast. Design throughput would have been 112 percent of normal.

National Grid RI
Forecast vs Actual Heating Degree Days and Natural Gas Throughput
2013-14 Heating Season

	Monthly Values						Cumulative Monthly Values					
	Heating Degree Days			Throughput (Dth)			Heating Degree Days			Throughput (Dth)		
Date	Actual	Normal	Design	Actual	Forecasted Normal	Forecasted Design	Actual	Normal	Design	Actual	Forecasted Normal	Forecasted Design
Oct-2013	309	339	345	2,230,013	2,330,903	2,619,322	309	339	345	2,230,013	2,330,903	2,619,322
Nov-2013	704	579	625	4,416,689	3,347,739	3,761,977	1,013	918	970	6,646,702	5,678,642	6,381,299
Dec-2013	977	931	1,196	6,137,733	5,717,635	6,425,116	1,990	1,849	2,166	12,784,435	11,396,277	12,806,415
Jan-2014	1,176	1,099	1,231	7,412,925	7,034,474	7,876,115	3,166	2,948	3,397	20,197,360	18,430,751	20,682,530

Date	HDD Actual / Normal	HDD Design / Normal	Throughput Actual / Normal	Throughput Design / Normal	Cumulative HDD Actual / Normal	Cumulative HDD Design / Normal	Cumulative Throughput Actual / Normal	Cumulative Throughput Design / Normal
Oct-2013	91%	102%	96%	112%	91%	102%	96%	112%
Nov-2013	122%	108%	132%	112%	110%	106%	117%	112%
Dec-2013	105%	128%	107%	112%	108%	117%	112%	112%
Jan-2014	107%	112%	105%	112%	107%	115%	110%	112%



C. Volume Changes since 2012 Long-Range Plan

The Company's 2012 Long-Range Plan forecasted volumes by rate class for the years 2012/13 through 2015/16.

Narragansett Electric Company d/b/a NATIONAL GRID
2012 National Grid Long-Range Plan
Plan-Year Forecasted Gas Deliveries by Rate Class in Dth (2012 - 2016)

Rate Code		2011/12	2012/13	2013/14	2014/15	2015/16
401	Residential non-heat (1012)	553,212	532,644	510,884	494,969	475,959
403	Residential non-heat Low Income (1101)	18,054	18,079	17,056	16,521	15,934
400	Residential heat (1247)	15,224,854	15,301,102	15,177,877	15,270,804	15,597,259
402	Residential heat Low Income (1301)	1,761,730	1,875,748	1,805,162	1,825,568	1,868,843
404	C & I small (2107)	2,384,514	2,466,997	2,515,942	2,515,959	2,523,717
405	C & I medium sales (2237+2231)	3,120,859	3,162,177	3,112,343	3,108,379	3,115,510
408	C & I medium sales (2237+2231)	0	0	0	0	0
407	C & I medium FT-1 (22EN)	797,546	810,046	742,289	717,552	715,055
406	C & I medium FT-2 (2221)	1,184,118	1,288,364	1,352,932	1,382,278	1,438,806
409	LLF large sales (3367)	662,747	698,401	769,437	822,037	863,212
411	LLF large FT-1 (33EN)	1,062,354	979,716	918,748	876,785	852,057
410	LLF large FT-2 (3321)	940,010	947,757	842,965	797,225	787,186
417	HLF large sales (2367)	270,540	275,867	278,908	279,303	279,405
419	HLF large FT-1 (23EN)	555,657	646,592	638,657	653,586	665,217
418	HLF large FT-2 (2321)	270,279	309,564	314,486	321,062	323,985
413	LLF XL sales (3496)	46,558	38,220	36,957	41,480	40,980
415	LLF XL FT-1 (34EN)	792,740	700,312	636,900	551,528	514,891
414	LLF XL FT-2 (3421)	95,105	120,179	90,109	82,486	89,934
421	HLF XL sales (2496)	177,492	181,248	183,182	179,954	184,506
423	HLF XL FT-1 (24EN)	4,086,277	3,980,270	4,003,238	4,013,962	4,023,420
422	HLF XL FT-2 (2421)	185,415	205,698	219,569	219,018	221,186
	Total	34,190,063	34,538,981	34,167,640	34,170,454	34,597,062

The Company shows actual historical volumes for the years 2011/12 and 2012/13 plus its forecast for 2013/14 through 2015/16 for the specified rate classes below.

Narragansett Electric Company d/b/a NATIONAL GRID
2014 National Grid Long-Range Plan
Actual 2011/12 and 2012/13, Forecasted 2013/14 - 2015/16 (Dth)

Rate Code		*2011/12*	*2012/13*	2013/14	2014/15	2015/16
401	Residential non-heat (1012)	*625,315*	*699,945*	685,875	692,027	705,409
403	Residential non-heat Low Income (1101)	*18,931*	*28,505*	28,918	28,918	28,918
400	Residential heat (1247)	*13,930,781*	*17,184,029*	16,488,706	16,425,085	16,563,775
402	Residential heat Low Income (1301)	*1,455,599*	*1,709,529*	1,773,915	1,771,359	1,775,139
404	C & I small (2107)	*2,040,763*	*2,548,200*	2,338,302	2,304,993	2,308,388
405	C & I medium sales (2237+2231)	*2,830,599*	*3,124,263*	3,096,957	3,081,813	3,086,285
408	C & I medium sales (2237+2231)	*36,309*	*34,913*	32,609	41,825	49,725
407	C & I medium FT-1 (22EN)	*655,985*	*649,729*	644,294	647,967	659,002
406	C & I medium FT-2 (2221)	*1,273,478*	*1,426,519*	1,454,208	1,477,111	1,511,701
409	LLF large sales (3367)	*555,840*	*596,618*	633,000	657,458	690,196
411	LLF large FT-1 (33EN)	*804,086*	*796,918*	810,778	817,628	833,527
410	LLF large FT-2 (3321)	*782,258*	*1,101,248*	1,142,095	1,202,657	1,277,527
417	HLF large sales (2367)	*250,571*	*311,430*	308,413	313,606	316,364
419	HLF large FT-1 (23EN)	*319,066*	*353,039*	354,084	353,259	353,759
418	HLF large FT-2 (2321)	*235,582*	*351,035*	373,674	372,189	374,311
413	LLF XL sales (3496)	*80,624*	*145,781*	169,332	186,437	205,208
415	LLF XL FT-1 (34EN)	*520,599*	*732,870*	972,624	992,712	1,014,749
414	LLF XL FT-2 (3421)	*40,920*	*28,352*	33,718	36,224	39,764
421	HLF XL sales (2496)	*198,743*	*240,930*	267,925	285,291	298,386
423	HLF XL FT-1 (24EN)	*1,012,591*	*1,192,511*	1,284,460	1,332,051	1,365,745
422	HLF XL FT-2 (2421)	*131,265*	*204,852*	227,761	236,205	249,008
	Total	*27,799,903*	*33,461,218*	33,121,647	33,256,816	33,706,886

The table below compares the 2012 Long-Range Plan forecasted volumes with the historical / forecasted volumes from the instant filing.

Narragansett Electric Company d/b/a NATIONAL GRID
2014 National Grid Long-Range Plan
Changes Since 2012 Long-Range Plan Forecast (Dth)

Rate Code		*2011/12*	*2012/13*	2013/14	2014/15	2015/16
401	Residential non-heat (1012)	*72,102*	*167,300*	*174,991*	*197,058*	*229,451*
403	Residential non-heat Low Income (1101)	*876*	*10,426*	*11,862*	*12,397*	*12,984*
400	Residential heat (1247)	*-1,294,073*	*1,882,927*	*1,310,829*	*1,154,281*	*966,516*
402	Residential heat Low Income (1301)	*-306,132*	*-166,219*	*-31,248*	*-54,209*	*-93,703*
404	C & I small (2107)	*-343,751*	*81,203*	*-177,640*	*-210,966*	*-215,330*
405	C & I medium sales (2237+2231)	*-290,260*	*-37,913*	*-15,386*	*-26,566*	*-29,225*
408	C & I medium sales (2237+2231)	*36,309*	*34,913*	*32,609*	*41,825*	*49,725*
407	C & I medium FT-1 (22EN)	*-141,560*	*-160,317*	*-97,995*	*-69,585*	*-56,054*
406	C & I medium FT-2 (2221)	*89,360*	*138,155*	*101,276*	*94,832*	*72,896*
409	LLF large sales (3367)	*-106,908*	*-101,783*	*-136,437*	*-164,579*	*-173,016*
411	LLF large FT-1 (33EN)	*-258,268*	*-182,798*	*-107,970*	*-59,157*	*-18,530*
410	LLF large FT-2 (3321)	*-157,752*	*153,491*	*299,130*	*405,432*	*490,341*
417	HLF large sales (2367)	*-19,969*	*35,564*	*29,506*	*34,303*	*36,958*
419	HLF large FT-1 (23EN)	*-236,591*	*-293,553*	*-284,573*	*-300,327*	*-311,459*
418	HLF large FT-2 (2321)	*-34,697*	*41,471*	*59,189*	*51,127*	*50,326*
413	LLF XL sales (3496)	*34,065*	*107,561*	*132,375*	*144,957*	*164,228*
415	LLF XL FT-1 (34EN)	*-272,142*	*32,559*	*335,724*	*441,185*	*499,858*
414	LLF XL FT-2 (3421)	*-54,185*	*-91,827*	*-56,391*	*-46,262*	*-50,170*
421	HLF XL sales (2496)	*21,251*	*59,682*	*84,743*	*105,338*	*113,880*
423	HLF XL FT-1 (24EN)	*-3,073,686*	*-2,787,758*	*-2,718,778*	*-2,681,910*	*-2,657,675*
422	HLF XL FT-2 (2421)	*-54,150*	*-846*	*8,192*	*17,187*	*27,823*
	Total	*-6,390,159*	*-1,077,763*	-1,045,993	-913,638	-890,176

D. Status of Conversions to Residential Heating

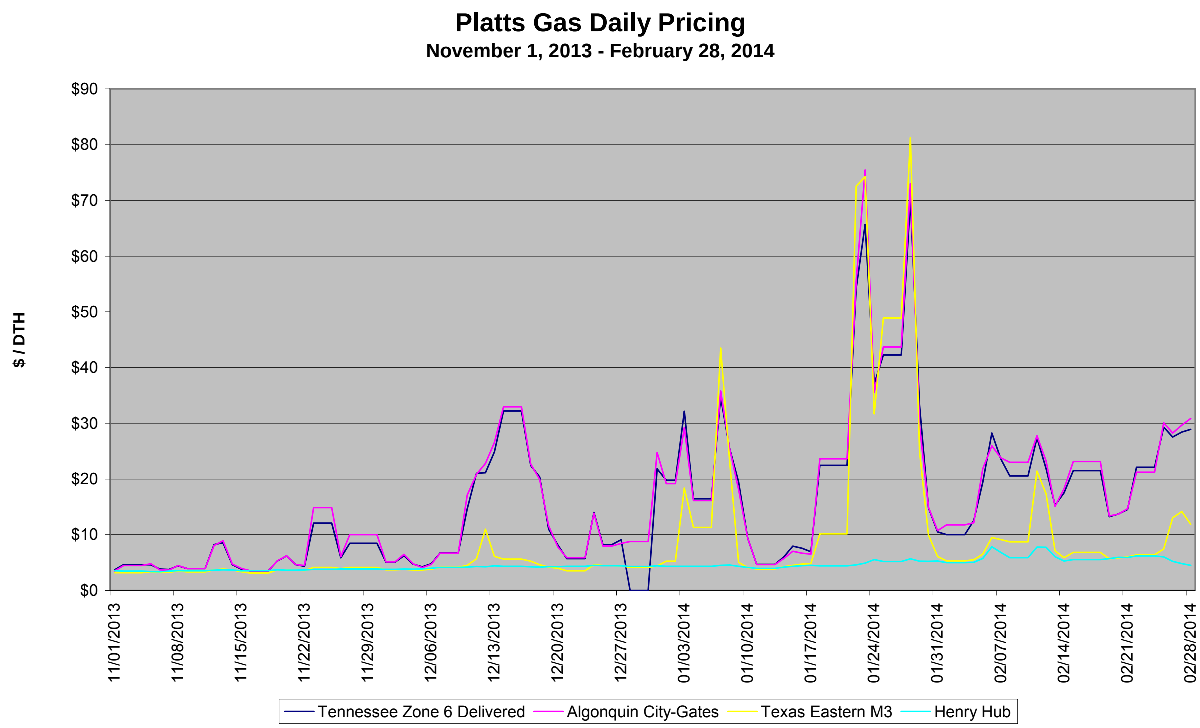
The Company's meter count forecast is a net forecast of new meters plus attrition. From Company records, the annual new meter count (low-use conversion and new construction) has ranged between 1,500 – 2,000 meters per year in the residential sector. This represents the bulk of all residential services installed.

E. Pricing Dynamics for 2013/2014 Peak Season

Throughout the 2013-14 peak season, the Northeast markets posted large increases in demand mostly due to periods of colder than normal weather. In January 2014, the Company experienced three of the top five highest sendouts in Company history within its service territory. The table below shows the top ten highest sendouts in Company history.

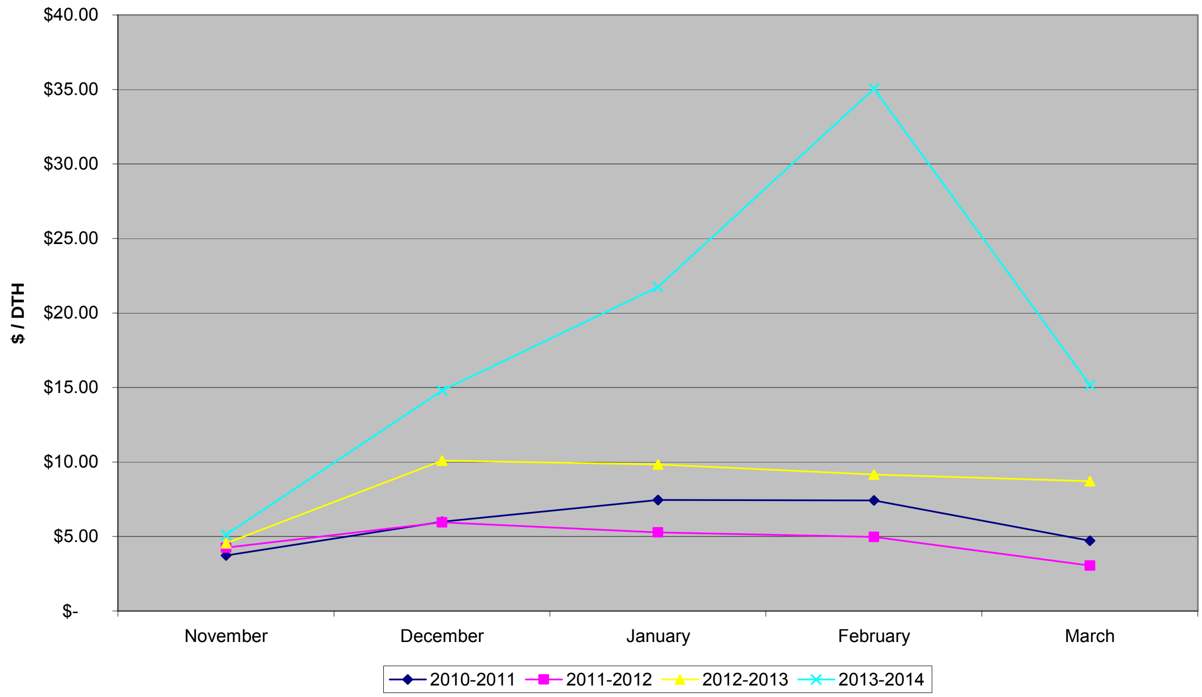
Rank	Date	Sendout	HDD
1	01-15-2004	351,459	64
2	01-03-2014	338,383	59
3	01-07-2014	333,749	55
4	01-16-2004	329,396	53
5	01-22-2014	328,864	55
6	01-09-2004	323,727	60
7	01-23-2013	320,826	55
8	01-22-2003	320,475	51
9	01-14-2004	319,420	59
10	01-24-2013	317,807	51

These high demands and other factors such as ongoing interstate pipeline constraints, compressor station outages and limited imported LNG supplies have contributed to increased costs in the New England area. Furthermore, US storage levels ended January at low levels not seen in 10 years. In January alone, per-dekatherm prices have ranged from $4.66 to $75.48 for the Algonquin Gas Transmission city-gates, $4.70 to $70.08 for Tennessee Gas Pipeline Zone 6 Delivered, and $3.85 to $81.30 for Texas Eastern Market Area zone M-3.

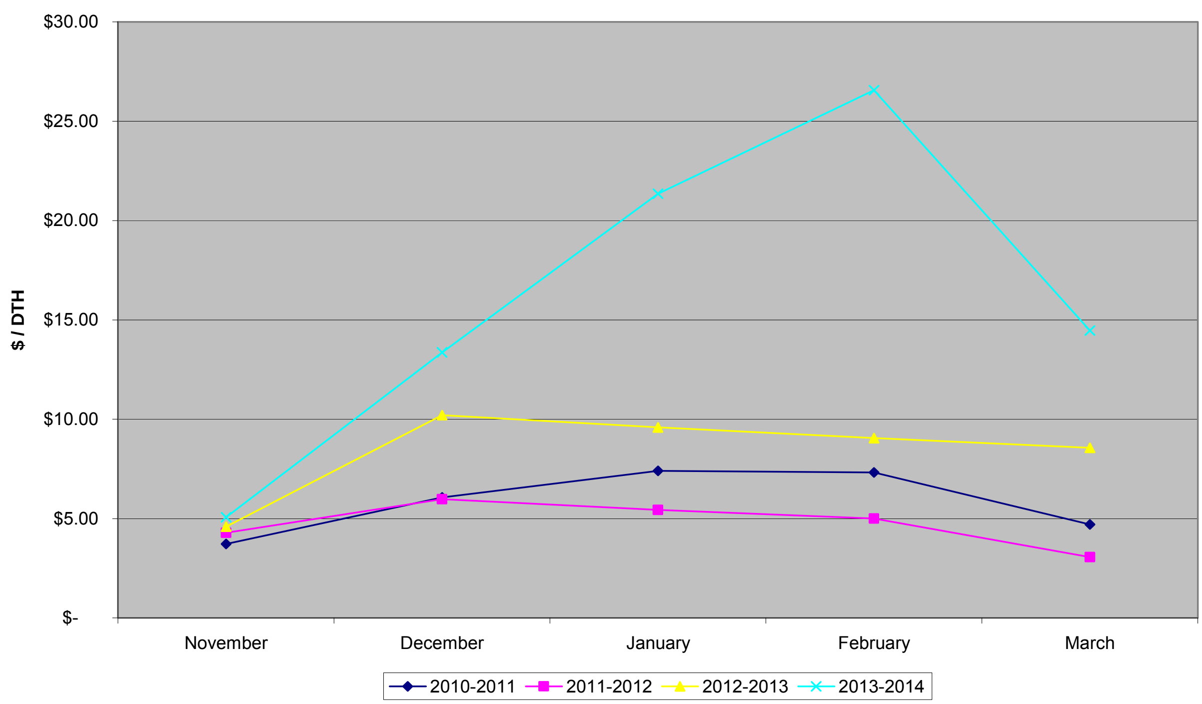


The graph above shows daily pricing for these points as published in "Platts Gas Daily" for the November 1, 2013 through February 28, 2014 time period in relation to the Henry Hub price. As depicted, the market experienced large spikes in these market-area prices during mid-December, the beginning of January and most of February, as well as a major spike at the end of January. The Company is subject to these prices when purchasing the HubLine and Dracut supplies, as well as supplies sourced on Algonquin from the Texas Eastern M-3 market area point.

Algonquin City-gates
November - March, Last 4 Years



Tennessee Zone 6, Delivered
November - March, Last 4 Years



The two graphs above show monthly pricing for Algonquin City-gates and Tennessee Zone 6 Delivered for the last four years, and as you can see, these Market Area points remain high each year. Ongoing pipeline constraints and colder than normal weather drove the cost of gas even higher this peak season and the Company was subject to these extremely expensive Market Area prices.