nationalgrid

Stacey M. Donnelly
Senior Counsel

November 1, 2022

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Boston Gas Company d/b/a National Grid; D.P.U. 22-XXX
November 1, 2022 through October 31, 2025 Long-Range Resource and Requirements Plan

Dear Secretary Marini:

Pursuant to G.L. c. 164, § 69I, enclosed please find the Long-Range Resource and Requirements Plan of Boston Gas Company d/b/a National Grid ("Company"), for the period November 1, 2022 to October 31, 2027.

In addition to the forecast and supply plan, the Company is filing pre-filed direct testimony of Elizabeth D. Arangio, Theodore Poe, Jr., and Maral Fakoor seeking approval to revise the forecast methodology.

Also enclosed, please find my Notice of Appearance, along with the Appearances of John K. Habib, Esq. and Ashley S. Marton of Keegan Werlin, LLP. If you have any questions, please do not hesitate to contact me.

Very truly yours,

Stacey M. Donnelly

Enclosures
cc: Stephanie Mealey – Department of Public Utilities
D.P.U. 20-132, Service List

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THE COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Boston Gas Company d/b/a National Grid	)	D.P.U. 22-XXX

ON BEHALF OF NATIONAL GRID

APPEARANCE OF COUNSEL

In the above referenced proceeding, I hereby appear for and on behalf of National Grid.

Respectfully submitted,

Stacey M. Donnelly
National Grid
40 Sylvan Road
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Dated: November 1, 2022

THE COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Boston Gas Company d/b/a National Grid | D.P.U. 22-XXX

ON BEHALF OF NATIONAL GRID

APPEARANCE OF COUNSEL

In the above-referenced proceeding, I hereby appear for and on behalf of National Grid.

Respectfully submitted,

John K. Habib
Keegan Werlin LLP
99 High Street, 29th Floor
Boston, MA 02110
TEL: (617) 951-1400

Dated: November 1, 2022

THE COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Boston Gas Company d/b/a National Grid	)	D.P.U. 22-XXX

ON BEHALF OF NATIONAL GRID

APPEARANCE OF COUNSEL

In the above-referenced proceeding, I hereby appear for and on behalf of National Grid.

Respectfully submitted,

A. Marton

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TEL: (617) 951-1400

Dated: November 1, 2022

THE COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Boston Gas Company d/b/a National Grid	))))	D.P.U. 22-_____

AFFIDAVIT OF ELIZABETH ARANGIO

Elizabeth Arangio does hereby depose and say as follows:

I, Elizabeth Arangio, on behalf of Boston Gas Company d/b/a National Grid, certify that Sections I, II, and IV of the Company’s Forecast and Supply Plan and Exhibit NG-1, filed on this date were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury as of this 1st day of November 2022.

____
Elizabeth Arangio

THE COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Boston Gas Company d/b/a National Grid	))))	D.P.U. 22-_____

AFFIDAVIT OF DEBORAH M. WHITNEY

Deborah M. Whitney does hereby depose and say as follows:

I, Deborah M. Whitney, on behalf of Boston Gas Company d/b/a National Grid, certify that Table G22 and G23 of the Company's Forecast and Supply Plan and Exhibit NG-1, filed on this date were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury as of this 1st day of November 2022.

Deborah M. Whitney

THE COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Boston Gas Company d/b/a National Grid	)	D.P.U. 22-_____

AFFIDAVIT OF MARAL FAKOOR

Maral Fakoor does hereby depose and say as follows:

I, Maral Fakoor, on behalf of Boston Gas Company d/b/a National Grid, certify that Section III of the Company's Forecast and Supply Plan and Exhibit NG-1, filed on this date were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury as of this 1st day of November 2022.

Maral Fakoor

Maral Fakoor

THE COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Boston Gas Company d/b/a National Grid	)	D.P.U. 22-_____

AFFIDAVIT OF THEODORE POE, JR.

Theodore Poe, Jr. does hereby depose and say as follows:

I, Theodore Poe, Jr., on behalf of Boston Gas Company d/b/a National Grid, certify that Section III of the Company's Forecast and Supply Plan and Exhibit NG-1, filed on this date were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury as of this 1st day of November 2022.

Theodore Poe, Jr

Theodore Poe, Jr.

Long-Range Resource and Requirements Plan of Boston Gas Company d/b/a National Grid for the Forecast Period 2022/23 to 2026/27

November 1, 2022

I. Introduction

This filing presents the Long-Range Resource and Requirements Plan ("Supply Plan") for Boston Gas Company[1] d/b/a National Grid ("National Grid" or the "Company"), for the forecast period November 1, 2022 through October 31, 2027. This filing is submitted to the Department of Public Utilities (the "Department") in compliance with G.L. c. 164 § 69I. Boston Gas Company provides natural gas sales and transportation service to approximately 925,000 residential and commercial customers in 129 cities and towns. This company is a wholly owned subsidiary of National Grid USA. In Boston Gas Company d/b/a National Grid, D.P.U. 20-132 (2020), the Department reviewed and approved the most recent consolidated supply plan for Boston Gas Company for the forecast period 2020/21 through 2024/25.

As a gas company operating under G.L. c. 164 § 1, the Company has an obligation to provide safe, reliable and least-cost gas service to its customers. 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 National Grid's Massachusetts customers at the lowest possible 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 and economic conditions.

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, commercial/industrial heating and commercial/industrial non-heating 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 results of the econometric models are augmented by a specific assessment of non-traditional markets, including natural gas vehicles and large-scale cogeneration projects. The Company then deducts from the results of its econometric models any incremental load reductions expected to be achieved through the implementation of its Energy Efficiency programs, because these reductions are exogenous to the demand forecast generated by the econometric models. The Company has also discretely analyzed the potential impacts of the Electrification of Heat, the Boston Building Emissions Reduction and Disclosure Ordinance (BERDO) and gas demand response efforts in its forecast to ensure its supply portfolio reasonably accounts for potential load reductions associated with these initiatives.

[1] Effective March 15, 2020, Colonial Gas Company was merged with Boston Gas Company, with Boston Gas Company as the surviving legal entity, as approved in Boston Gas Company and Colonial Gas Company d/b/a National Grid, D.P.U. 19-69 (2019).

The results of the Company's normal year sendout requirements forecast (Chart III-A-1)[2] indicates that, over the five-year forecast period for capacity-eligible customers, the residential heating market is projected to increase by an average of 2,042 BBtu per year, the residential non-heat market is projected to decline by an average of 60 BBtu per year and the commercial/industrial market is projected to grow by 932 BBtu per year.

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 projected total sendout increase (excluding powerplants) over the forecast period averaging 2,977 BBtu (approximately 1.8%) per year under normal weather conditions (Chart III-A-1).

To ensure that the Company maintains adequate supplies in its portfolio to meet the projected customer load requirements, the second step in the planning process involves establishing its design year and design day planning standards. In this filing, the Company maintains its standards for design day from its D.P.U. 20-132 filing and proposes a new design year. The Company's revised design year is 7,060 EDD. It is based on the same probability of occurrence of 1in 34.4 years as approved in D.P.U. 20-132, but it reflects the continued slow decline in observed annual EDD. The Company's design day remains at 78 EDD with a decreased frequency of occurrence of 1 in 47.9 years using the Company's entire 51 year history of EDD weather data. Combining the results of the design planning standards definition and the load forecasting process, the Company is projecting its Base Case design-year total sendout (excluding powerplants) to increase over the forecast period by an average of 3,343 BBtu (Chart III-A-1), or approximately 1.8 %, per year, and design day sendout to increase by an average of 34 BBtu, or 2.1%, per year (Table G-5 (B)).

After the forecast of customer requirements is 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 New Energy Associates now ABB) 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 base-case conditions, as well as high and low alternative demand scenarios and a cold snap weather scenario. In the base case, the Company forecasts an average annual increase in sendout requirements under design conditions of approximately 34 BBtu per day for its design day. The Company's resource plan is sufficient to meet base-case design-day and design-year load requirements in year 2022/2023. Beyond the first year, additional resources are needed including but not limited to, additional short-term firm citygate delivery arrangements, incremental long-term capacity resources, on-system resources and/or non-pipeline alternatives.d. This result is similar under both the high-demand and low-demand scenarios.

For the cold-snap weather scenario, the Company has used a 14-day cold snap occurring in the coldest 14-day period of the Company's normal year (9 January - 22 January) by evaluating

2 Chart III-A-1 and the remaining charts referenced in the Supply Plan are provided in Appendix B.

January weather data from 1976 - 2015, 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 year 2022/23. Beyond the first year, additional short-term firm citygate delivery arrangements and/or incremental long-term capacity resources are needed.

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 summary of conditions required by the Department in D.P.U. 20-132 (2020) (the "Order"); and
- Section VI contains the required G-tables for the filing.

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 the lowest possible cost.

III. Forecast Methodology

III.A. Introduction

The Company's[3] forecast methodology supports its supply planning goals of ensuring that: (1) its resource portfolio maintains sufficient supply deliverability to meet customer requirements on the coldest planning day ("design day"); and (2) it maintains sufficient supplies under contract and in storage (underground storage, LNG and propane) to meet customers' requirements over the coldest planning year ("design year"). Each year, the Company employs the same process and it prepares a ten-year forecast 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, herein, "customer" is defined as a customer for whom the Company must make capacity planning decisions.

The Company develops its customer requirements forecast from econometric models of its customer billing data. This data is available by month and by rate class for the four geographic divisions of the Company. One of the goals of the Company's modeling exercise is to translate the Company's monthly forecast of billed sales data (which are lagged in time due to the Company's monthly billing cycle schedule) into a forecast of unlagged daily resource requirements at the Company's city gates. This translation involves accounting for Company use and billing lag each calendar month, quantifying unaccounted-for gas, and allocating these monthly volumes to daily volumes. The Company models its resources and requirements on a daily basis with its SENDOUT® linear programming software modeling package, and hence it needs as input a forecast of daily customer requirements.

Based on the forecast, National Grid projects incremental sendout to its retail markets of 11,908 BBtus over the forecast period or 2,977 BBtus per year (assuming normal weather) (see Chart III-A-1, Base Case). Overall, this growth represents a 7.6 % total increase in sendout requirements over the forecast period, or 1.8 % per year on average. The development of National Grid's five-year forecast of customer sendout requirements, based on the steps set forth above, is described in the following sections.

III.B. Forecast of Customer Billing Data ("Demand Forecast")

III.B.1. Introduction

The first step in the Company's forecasting methodology is the generation of its retail demand forecast. The Company's demand forecast is comprised of two forecasts: a forecast of traditional (residential and commercial/industrial) markets which can be analyzed through econometric modeling and a forecast of its non-traditional markets that is developed using Company market information specific to those markets.

The Company's econometric modeling of its traditional markets can be characterized by:

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[3] Effective March 15, 2020, Colonial Gas Company was merged with Boston Gas Company, with Boston Gas Company as the surviving legal entity, as approved in Boston Gas Company and Colonial Gas Company d/b/a National Grid, D.P.U. 19-69 (2019).

- Using linear regression analysis of the number of customers and of the use-per-customer by rate category for each service territory, where historical use-per-customer is calculated from billed volumes divided by the number of customers.
- Identifying separately sales, capacity-eligible transportation ("Customer Choice"), and capacity-exempt transportation data.
- Basing its models on quarterly data.
- Minimizing the use of time-series analysis.
- Deriving its volume forecast through the product of number of customers times use-per-customer.
- Parsimonious reliance on indicator variables.
- Relying on independent variables whose t-statistics are greater than 2.0 to the greatest extent possible.
- Testing and correction for autocorrelation and/or heteroscedasticity which might occur in the residuals of the various models.
- Selecting stable models using Chow tests and ex-post forecast analyses.

III.B.2. Retail Demand Forecast

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 March 2007 through February 2022 to define two dependent variables in its econometric modeling: number of customers and use-per-customer (volume divided by number of customers). The data was prepared for each of the four divisions which are the service territories of the four National Grid Massachusetts legacy companies: Boston Gas, Essex Gas, Colonial Gas/Lowell, and Colonial Gas/Cape Cod.

The billing data was modeled at the customer class level for the residential heat, residential non-heat, commercial/industrial low-load factor, commercial/industrial high-load factor, and an 'Other' category. The Company's 'Other' category, representing company use, gas lighting, and large-volume transportation. These customer classes include customers receiving Sales service, Capacity-Eligible Transportation service, and Capacity-Exempt Transportation service. From Chart III-A-1 (Base Case), residential heating retail volumes represent approximately 54 % of annual volumes in the Company's capacity-eligible market, residential non-heating represents 1 %, commercial / industrial low-load factor represents 31%, and commercial / industrial high-load factor represents 12%. The table below lists the relevant customer classes by division used in the Company's analysis.

Division	Customer Segment	Rate Classes
Boston	Residential Non-heating	R-1, R-2, R-1T, R-2T
	Residential Heating	R-3, R-4, R-3T, R-4T

Division	Customer Segment	Rate Classes
	C&I Low-Load Factor	G-41, G-42, G-43, G-44, G-41T, G-42T, G-43T, G-44T
	C&I High-Load Factor	G-51, G-52, G-53, G-54, G-51T, G-52T, G-53T, G-54T
	Other	G-7, G-17, G-81T, G-82T
Essex	Residential Non-heating	R-1, R-2, R-1T, R-2T
	Residential Heating	R-3, R-4, R-3T, R-4T
	C&I Low-Load Factor	G-41, G-42, G-43, G-41T, G-42T, G-43T
	C&I High-Load Factor	G-51, G-52, G-53, G-51T, G-52T, G-53T
	Other	G-81T, G-82T
Lowell	Residential Non-heating	R-1, R-2, R-1T, R-2T
	Residential Heating	R-3, R-4, R-3T, R-4T
	C&I Low-Load Factor	G-41, G-42, G-43, G-41T, G-42T, G-43T
	C&I High-Load Factor	G-51, G-52, G-53, G-51T, G-52T, G-53T
	Other	G-81T, G-82T
Cape Cod	Residential Non-heating	R-1, R-2, R-1T, R-2T
	Residential Heating	R-3, R-4, R-3T, R-4T
	C&I Low-Load Factor	G-41, G-42, G-43, G-41T, G-42T, G-43T
	C&I High-Load Factor	G-51, G-52, G-53, G-51T, G-52T, G-53T
	Other	G-81T, G-82T

Table 1

Independent variables for the forecast models include measures for weather, demographic conditions, and economic conditions. Historical and projected values of the economic independent variables were obtained from Moody's Analytics. The general data and variable categories that were utilized in the development of the forecast are described in the following sections.

III.B.2.a.1 Customer Segment Data

The Company analyzed monthly billing data by customer class for its Boston, Essex, Lowell, and Cape Cod divisions for historical periods ending February 2022 (2022 Q1). The Company's customer class data was aggregated into the four customer segments.

The following is a summary of the process that was used to develop quarterly Customer Segment data:

- Company billing month meter count and usage data for each internal rate code was collected for the historical period March 2007 through February 2022;
- The billing month Customer Segment data was aggregated into billing quarters to be used as dependent variables in the customer and use per customer quarterly forecast models. Volume data was summed into quarterly data; meter count data at the end of the quarter was used as the quarterly value.

III.B.2.a.2 Weather Variable

Effective Degree Days ("EDDs") as measured at the Boston/Logan International Airport were utilized as the weather measure. EDDs are Heating Degree Days ("HDDs") adjusted for average daily wind speed. Daily weather data is provided by Weather Services International, a consulting firm with offerings including weather research. The historical daily EDD data was converted to a billing quarter basis to be used in the quarterly forecast models.

In 2017, the Company had tested the quality of using EDD as its weather variable by running an additional series of analyses for its Boston division separating the EDD variable into two variables: HDD and wind speed. Comparison of these results with similar analyses using only EDD showed that:

- There were improvements in adjusted R-square and standard error only 50% of the time; and,
- The sign of the wind speed variable, expected to be positive, was negative 30% of the time.

The Company's conclusion was that changing from EDD to HDD plus wind speed was not a simple and successful improvement in its analyses and it continues to investigate other ways that it can possibly make improvements.

III.B.2.a.3 Economic and Demographic Variables

Economic theory suggests that demand may also be affected by economic and demographic variables. To reflect economic and demographic conditions for the Company's operating divisions, the Company obtained the following county-level economic data from Moody's Analytics for the period from 2007Q2 through 2022Q1 and forecasted data from 2022Q2 onward The Company's service territories' gross domestic product (GDP), the broadest measure of area economic activity, increased 7.8% in 2021, or 3.1 percentage points more than last year's forecast of 4.7% growth which assumed a strong recovery from the 2020 COVID-19 recession. The economic rebound was stronger than forecast because of extraordinary growth in the area biotech, IT, finance and tourism industries in 2021. Moderna and other Boston biotech firms benefitted from the high demand for COVID-19 vaccines and treatments. IT and professional services activity grew as businesses implemented new systems to support remote and hybrid work arrangements. Boston's large finance industry benefited from soaring stock and bond prices. On Cape Cod, tourism experienced greater than expected gains as demand for domestic vacations soared, especially with people still leery of foreign travel. Because of these factors, the MA Gas service area economy grew more than forecast in 2021 despite unforeseen outbreaks of the Delta and Omicron COVID-19 variants.

However, the 2022 economic outlook has been revised down from last year, with the Company's territory GDP growth lowered from 5.8% to 4.3%. The primary reasons are the unanticipated war in Ukraine, the unexpected spike in inflation, and restrictive monetary and fiscal policy. High inflation, which has been driven by shortages related to COVID-19 lockdowns abroad and reductions in global oil supplies due in part to sanctions on Russia, has prompted much more restrictive monetary policy than anticipated last year. Also, fiscal policy has become a drag on economic growth in 2022 because of reduced federal spending whereas last year's forecast assumed an increase in federal spending due to passage of President Biden's "Build Back Better" program. Finally, the fall in stock and bond prices has lowered growth expectations in the financial sector, while labor shortages have done the same for tourism and hospitality even as demand continues to rise. Despite these headwinds, 2022 GDP growth, at 4.2%, is still about double the growth experienced pre-COVID.

Over the longer term, from 2023 on, the Company's territory GDP is expected to grow 2.2% per year on average, which is slightly higher than last year's forecast of 2.1% average growth. The current forecast assumes that any future pandemic outbreaks will be less disruptive to the economy than in 2021 and 2022.

Variable	Description
HH	Total Households, (Ths., SA)
POP	Total Population, (Ths., SA)
GDP	Gross Product: Total, (Mil. Chained 2005 $)
INCOME	Income: Total Personal, (Mil. $, SAAR)
ICP	Income: Per Capita, (2005 $, SAAR)
RETSALES	Total Retail Sales, ($2005)
EMPL	Employment: Total nonfarm, (Ths.)
CONST	Employment: Construction, (Ths.)
MFG	Employment: Manufacturing, (Ths.)
TOTHSTOCK	Total Housing Stock (Ths.)
NONMFG	Calculated from EMPL minus MFG (Ths.)

Table 2

III.B.2.a.4 Natural Gas and Oil Price Variables

Economic theory also suggests that demand is likely to be influenced by price. The Company developed natural gas price variables and oil prices variables listed in the table below to be included in the customer segment models. Residential, commercial, and industrial delivered natural gas prices were developed for Boston/Essex and Colonial Lowell/Cape Cod from Company data. State-level residential, commercial, and industrial delivered oil prices were developed from DOE/EIA data.

The forecast assumes that global oil prices, which have stabilized around $100 per barrel, will not rise further on a sustained based. Natural gas prices, which have risen along with oil prices, but not as much in the US, are expected to remain low compared to oil, maintaining a gas price advantage over oil.

Variable	Description
NGPRCR	Residential Natural Gas Price
NGPRCC	Commercial Natural Gas Price
NGPRCI	Industrial Natural Gas Price
OILPRCR	Residential Oil Price
OILPRCC	Commercial Oil Price
OILPRCI	Industrial Oil Price
NGPRCCI	Commercial and Industrial Natural Gas Price
OILPRCCI	Commercial and Industrial Oil Price
GORR	Natural Gas and Oil Ratio for Residential sector
GORC	Natural Gas and Oil Ratio for Commercial sector
GORI	Natural Gas and Oil Ratio for Industrial sector
GORCI	Natural Gas and Oil Ratio for Commercial and Industrial sector

Table 3

III.B.2.a.5 Time

The Company's data is aggregated to the quarterly level. The definitions of the quarters are:

- Q1: Dec, Jan, Feb
- Q2: Mar, Apr, May
- Q3: Jun, Jul, Aug
- Q4: Sep, Oct, Nov

III.B.2.a.6 Modeling Methodology

The output of the Company's modeling process is a monthly forecast of retail meter counts and volumes by Customer Segment that serves as the input to the development of the daily wholesale-level volumes required for the gas resource planning documented in Section IV. To derive this, the Company models meter counts and use per customer; the product of its meter count forecast and its use per customer forecast is the volume forecast.

In performing its modeling, the Company attempts to find the best econometric models for each of 60 possible combinations of:

- Four companies (Boston, Essex, Lowell, and Cape Cod)
- Three categories (meter counts, use per customer in the heating season, and use per customer in the non-heating season)
- Five markets (Residential Heating, Residential Non-Heating, Commercial / Industrial Low Load Factor, and Commercial / Industrial High Load Factor, Other)

In this filing, the Company did not choose to model Sales, Customer Choice, and Capacity-Exempt separately because movement between these three categories of service does not have a meaningful effect on the Company's forecast data.

To facilitate the econometric model selection, the Company followed a process for each of the 60 models to identify statistically-acceptable model candidates. To perform its regression analysis, the Company used version 4.1.2 of the R statistical software package[4]. For each model, the Company selected the appropriate possible independent variables based on economic theory. The Company then used the stepwise regression to determine the best one-variable up to five-variable combinations of independent variables. Ultimately, the Company would choose one or two independent variables which would produce satisfactory models in terms of R2 without collinearity between the variables. To mitigate the impact of structural changes, one or more indicator variables could be added.

Candidate models were then tested to ensure that they satisfied the following statistical constraints:

4 "R is a language and environment for statistical computing and graphics. It is free, open source, and well documented. It is widely used for forecasting and statistical programming.

- The t-statistics and F-statistics must be significant (pValue <= 0.05)
- The White test for heteroscedasticity of the residuals and the Chow test for stability of the model must be insignificant (pValue > 0.05) or less than the critical value
- The fitted error must be less than 15%
- The ex-post error must be less than 10%
- The change of parameters of the ex-post must be less than 15%
- The Durbin-Watson and Breusch-Godfrey tests must indicate no autocorrelation of the residuals.

If autocorrelation of the residuals was detected, then the Company re-ran the model using the 'fable' package in R and re-tested to ensure that:

- The fitted error must be less than 15%
- The ex-post error must be less than 10%
- The change of parameters of the ex-post must be less than 15%

Candidate models which passed the above test were then considered as final candidate models. The final models and their statistical test results are presented in Appendix A.

III.B.2.b. Meter Count Models

III.B.2.b.1 Residential Heating -- Introduction

Residential Heating customers use natural gas for space heating purposes as well as other residential applications (e.g. cooking, hot water heating, clothes drying). Growth in the Residential Heating market is driven by migration of Residential Non-Heating customers to Residential Heating and new customers (either new construction or extension of the Company's distribution system into an area previously unserved by natural gas).

Economic theory suggests that the number of Residential Heating customers may be positively correlated with such variables as a measure of the number of people living in the service territory (e.g., households or population); measures of income or wealth (e.g. GDP, personal income, per capita personal income, employment levels); and measures that reflect the competitiveness of natural gas relative to other energy types (e.g. oil price).

Economic theory suggests that the number of Residential Heating customers may be negatively correlated with measures that reflect the loss of competitiveness of natural gas relative to other energy types (e.g. natural gas price, gas-to-oil price ratio).

In addition, the number of Residential Heating customers can reflect a quarterly seasonal pattern; generally, the greatest number of Residential Heating customers take service in Quarter 1, and the fewest number of Residential Heating customers take service in Quarter 3. This pattern may be associated with housing construction and bill payment.

III.B.2.b.2 Residential Non-Heating -- Introduction

Residential Non-Heating customers use natural gas for only non-space heating purposes (e.g. cooking, hot water heating, clothes drying). The Company's Residential Non-Heating market has been decreasing over the historical period due to migration of Residential Non-Heating customers to Residential Heating.

Economic theory suggests that the number of Residential Non-Heating customers may be negatively correlated with such variables as measures of income or wealth (e.g. GDP, personal income, per capita personal income, employment levels); and measures that reflect the competitiveness of natural gas relative to other energy types (e.g. natural gas price, oil price, gas-to-oil price ratio) as customers seek to leave the Non-heating class and convert to Heating service.

In addition, the number of Residential Non-Heating customers can reflect a quarterly seasonal pattern; generally, the greatest number of Residential Non-Heating customers take service in Quarter 1, and the fewest number of Residential Non-Heating customers take service in Quarter 3. This pattern may be associated with housing construction and bill payment.

III.B.2.b.3 Commercial / Industrial Low Load Factor (LLF or Commercial) -- Introduction

Commercial / Industrial Low Load Factor customers use natural gas for space heating purposes as well as other commercial applications (e.g. cooking, hot water heating). Growth in the Commercial / Industrial Low Load Factor market is primarily driven by migration from other fuel types and new customers (either new construction or extension of the Company's distribution system into an area previously unserved by natural gas).

Economic theory suggests that the number of Commercial / Industrial Low Load Factor customers may be positively correlated with such variables as a measure of the number of people living in the service territory (e.g., households or population); measures of income or wealth (e.g. GDP, personal income, per capita personal income, employment levels, retail sales); and measures that reflect the competitiveness of natural gas relative to other energy types (e.g. oil price).

Economic theory suggests that the number of Commercial / Industrial Low Load Factor customers may be negatively correlated with measures that reflect the loss of competitiveness of natural gas relative to other energy types (e.g. natural gas price, gas-to-oil price ratio).

In addition, the number of Commercial / Industrial Low Load Factor customers can reflect a quarterly seasonal pattern; generally, the greatest number of Commercial / Industrial Low Load Factor customers take service in Quarter 1, and the fewest number of Commercial / Industrial Low Load Factor customers take service in Quarter 3. This pattern may be associated with construction and bill payment.

III.B.2.b.4 Commercial / Industrial High Load Factor (HLF or Industrial) -- Introduction

Commercial / Industrial High Load Factor customers use natural gas for non-space heating purposes, principally process loads. Growth in the Commercial / Industrial High Load Factor market is primarily driven by migration from other fuel types and new customers (either new construction or extension of the Company's distribution system into an area previously unserved by natural gas).

Economic theory suggests that the number of Commercial / Industrial High Load Factor customers may be positively correlated with such variables as a measure of the number of people living in the service territory (e.g., households or population); measures of income or wealth (e.g. GDP, personal income, per capita personal income, employment levels, retail sales); and measures that reflect the competitiveness of natural gas relative to other energy types (e.g. oil price).

Economic theory suggests that the number of Commercial / Industrial High Load Factor customers may be negatively correlated with measures that reflect the loss of competitiveness of natural gas relative to other energy types (e.g. natural gas price, gas-to-oil price ratio).

In addition, the number of Commercial / Industrial High Load Factor customers can reflect a quarterly seasonal pattern; generally, the greatest number of Commercial / Industrial High Load Factor customers take service in Quarter 1, and the fewest number of Commercial / Industrial High Load Factor customers take service in Quarter 3. This pattern may be associated with construction and bill payment.

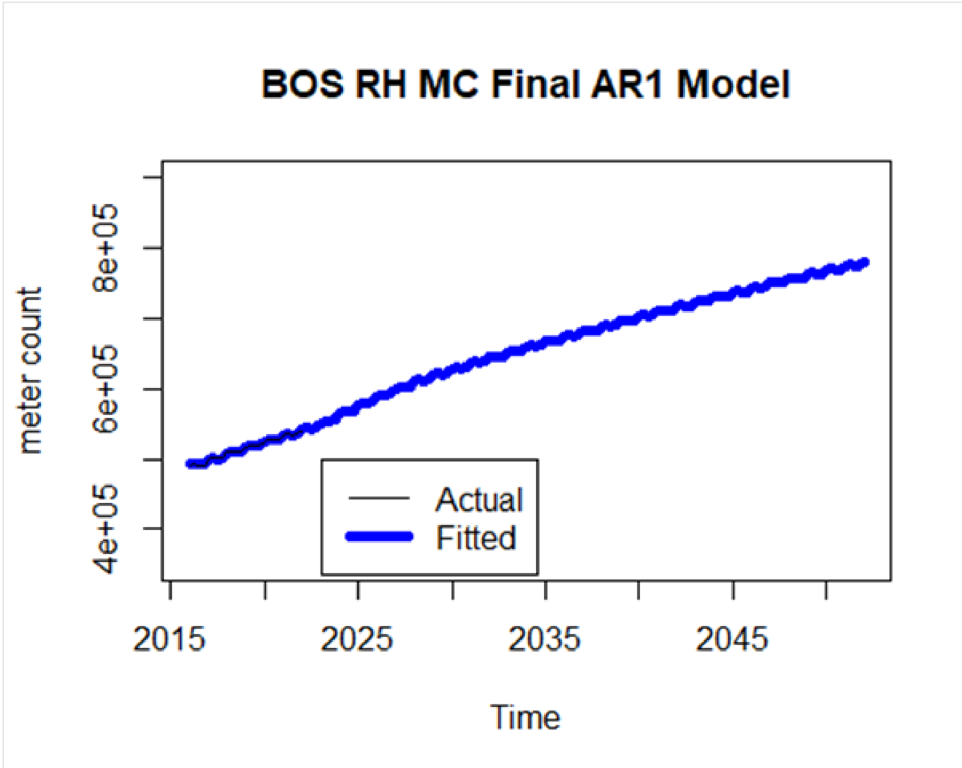
III.B.2.b.5 Other -- Introduction

Other customers, identified in Table 1 above, consists primarily of the Company's high-volume transportation customers. They will tend to follow the usage patterns of the High Load Factor customers so the Company used the same economic concepts as it used for the HLF customers (see Section III.B.2.b.4) in modeling the Other customers.

III.B.2.b.6 Boston Residential Heating Meter Count Model

For its Boston Residential Heating meter count model, the Company developed a model using total housing stock, and Q3 and Q4 dummies. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment. For this model:

- All predicted/actual 'pct error' < 1%.
- MAPE = 0.17%
- All four AR1 ex-post predicted values < 1% error.
- All AR1 parameters in the ex-post change by less than 6%

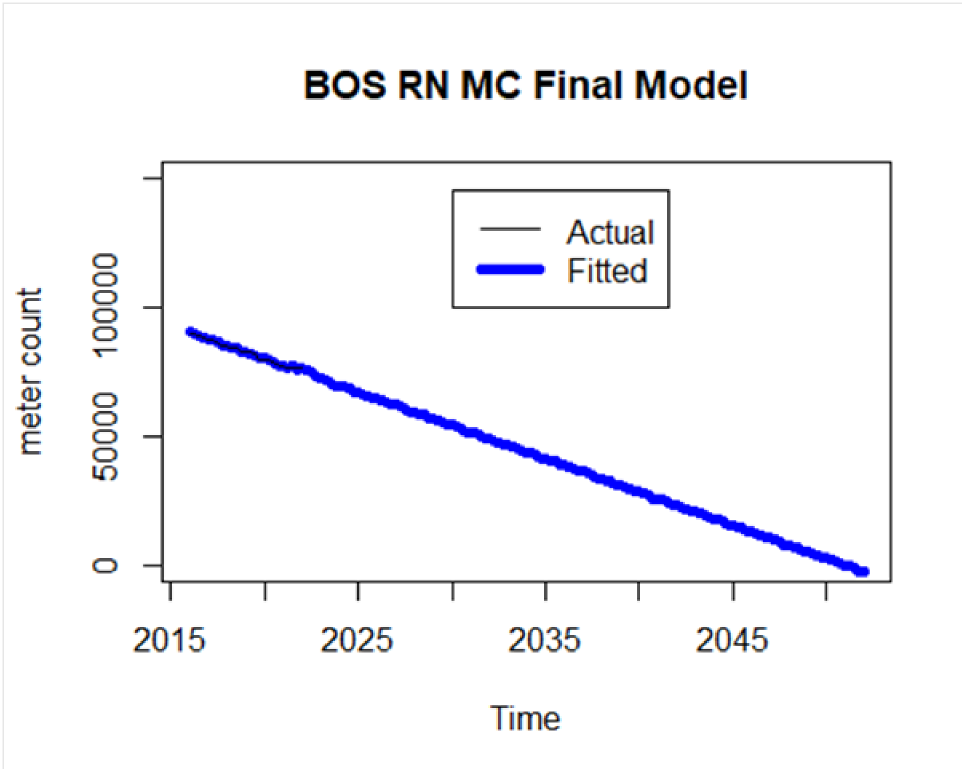


III.B.2.b.7 Boston Residential Non-Heating Meter Count Model

For its Boston Residential Non-Heating meter count model, the Company developed a model using time, the Q4 indicator variable, and one indicator variable to address COVID outliers. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 1.2%.
- MAPE = 0.37%
- All four ex-post predicted values < 2.1% error.
- All parameters in the ex-post change by less than 1%, except for the Q4 indicator variable.

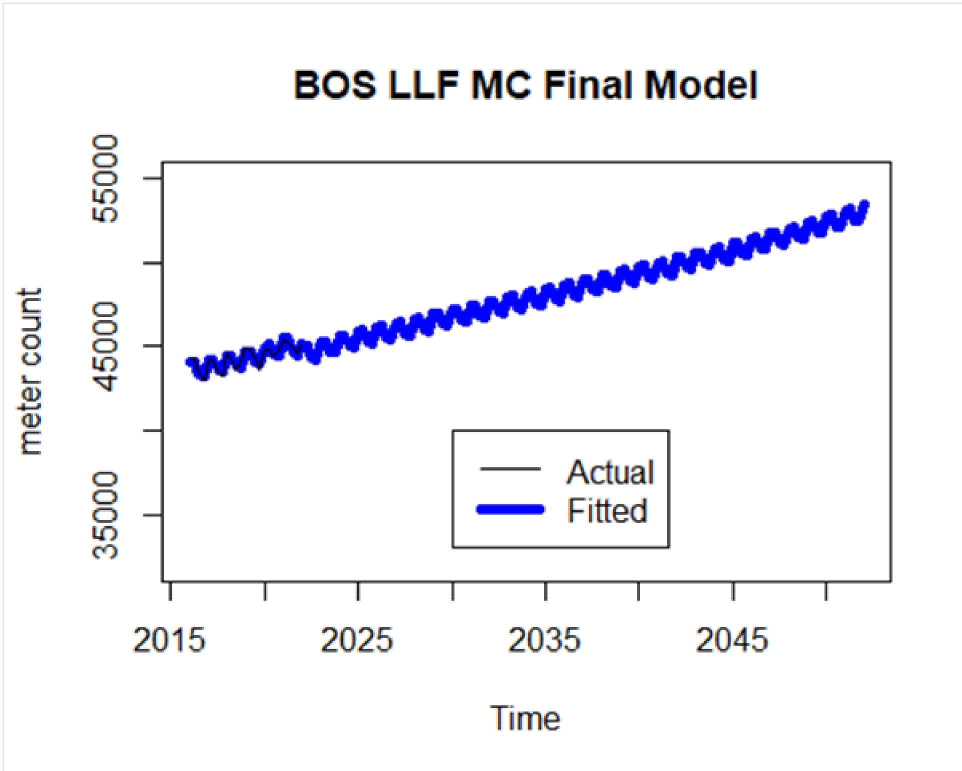
Given that this historical meter count data is highly linear through the years 2007-2022 (i.e. through the 'Great Recession' and recovery), the time variable seems most appropriate as the data reflects a market, not driven by economic factors, but a constrained market where the non-heating customers are converting at a fixed rate. This can be due to the failure rate of their existing non-gas-fired heating equipment over time.



III.B.2.b.8 Boston Commercial / Industrial Low Load Factor (LLF) Meter Count Model

For its Boston Commercial / Industrial Low Load Factor meter count model, the Company developed a model using personal income, and the Q3 and Q4 indicator variables. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.87. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model demonstrated no AR(1) autocorrelation of its. For this model:

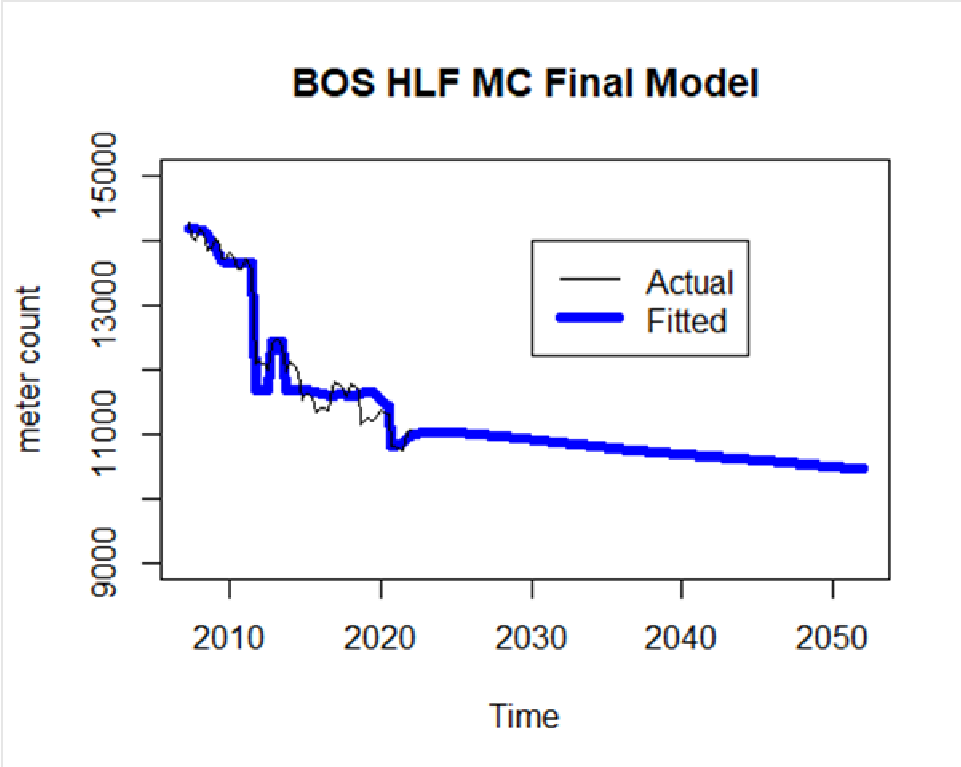
- All predicted/actual 'pct error' < 1%.
- MAPE = 0.43%
- All four ex-post predicted values < 1% error,
- All parameters in the ex-post change by less than 9%.



III.B.2.b.9 Boston Commercial / Industrial High Load Factor (HLF) Meter Count Model

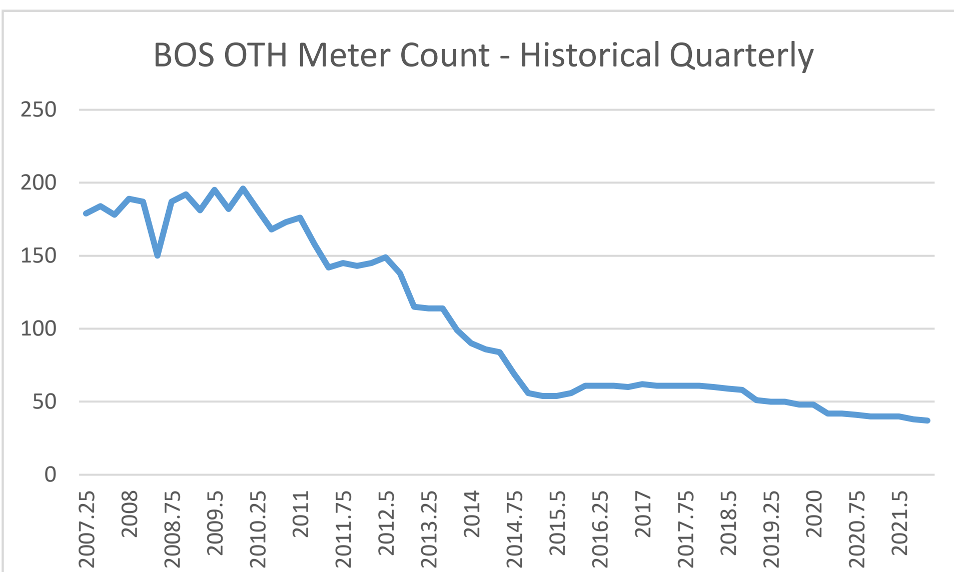
For its Boston Commercial / Industrial High Load Factor meter count model, the Company developed a model using manufacturing employment and three dummy variables to account for various structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.96. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals, however, the Company chose the non-AR model as it fit the historical data better and its MAPE was lower. For this model:

- All predicted/actual 'pct error' < 4%.
- MAPE = 1.4%
- All four ex-post predicted values < 1.2% error.
- All AR1 parameters in the ex-post change by less than 1.5%.



III.B.2.b.10 Boston Other Meter Count Model

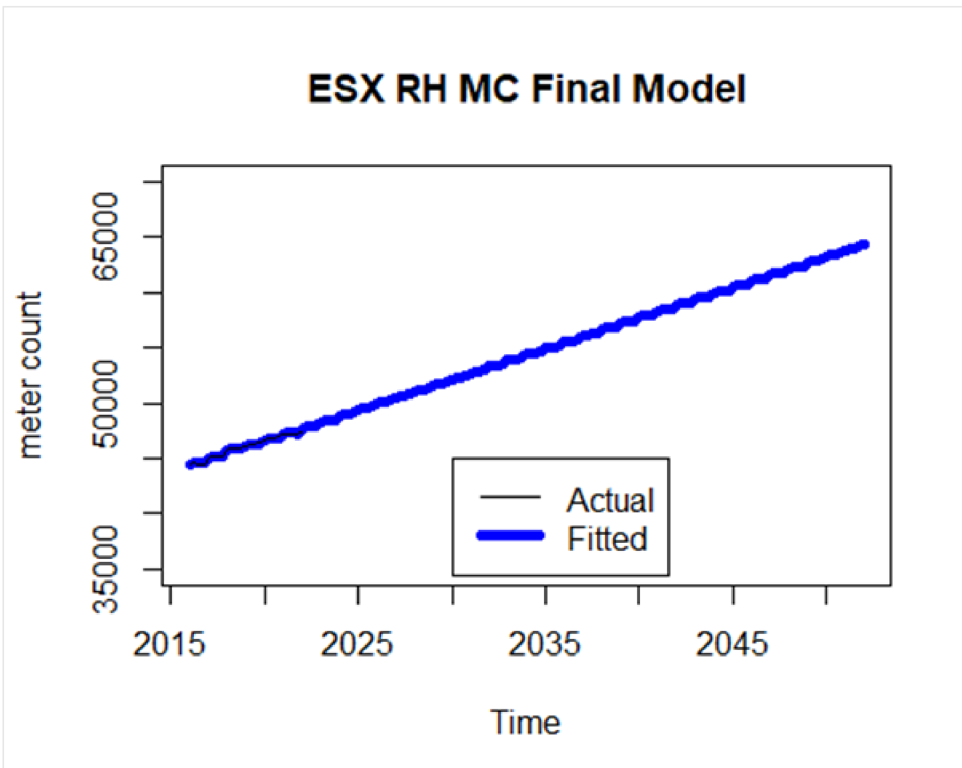
The Company tested the various economic and price variables as possible drivers of the meter count for the Other rate group, but it was unable to develop a statistically acceptable model . Any of the possible equations violated the statistical tests the Company uses to develop its models (e.g. t-statistics were not greater than 2.0, ex-post analysis did not reliable predict the final values, etc.). Hence, it chose to hold the meter count forecast to 37 meters, the most recent value.



III.B.2.b.11 Essex Residential Heating Meter Count Model

For its Essex Residential Heating meter count model, the Company developed a model using time, and the Q3 and Q4 dummy variables, and two dummy variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

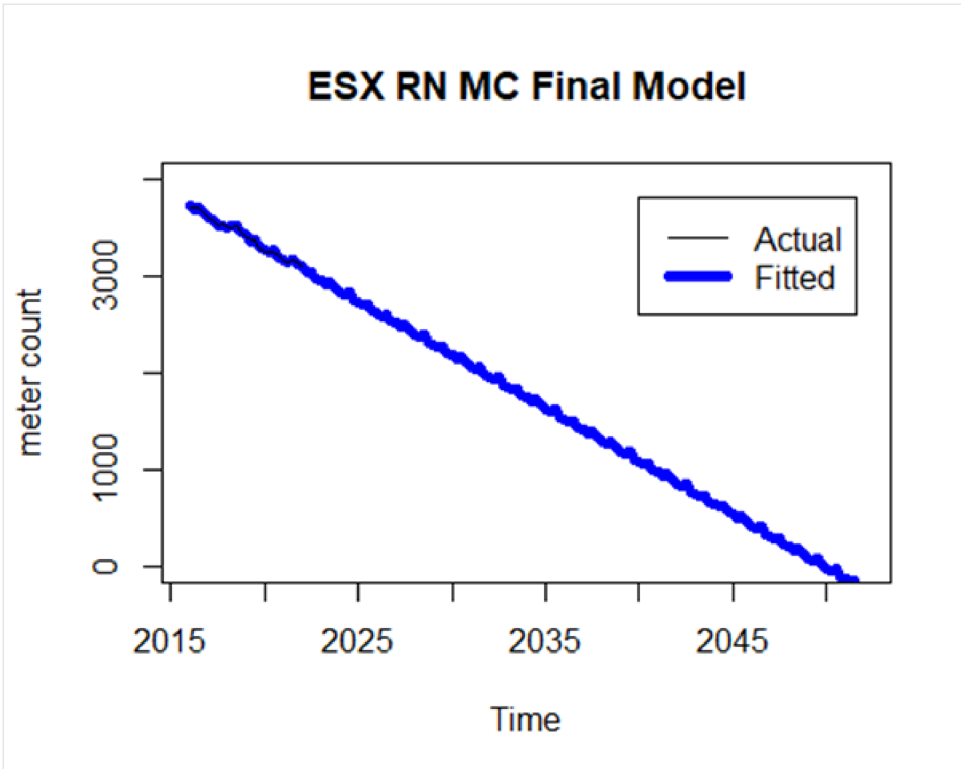
- All predicted/actual 'pct error' < 1%.
- MAPE = 0.12%
- All four ex-post predicted values < 1% error,
- All parameters in the ex-post change by less than 15% except for the Q4 dummy.



III.B.2.b.12 Essex Residential Non-Heating Meter Count Model

For its Essex Residential Non-Heating meter count model, the Company developed a model using time, the Q3 indicator, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, and the model did not pass the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 1%.
- MAPE = 0.26%
- All four ex-post predicted values < 1% error.
- All parameters in the ex-post change by less than 8%.

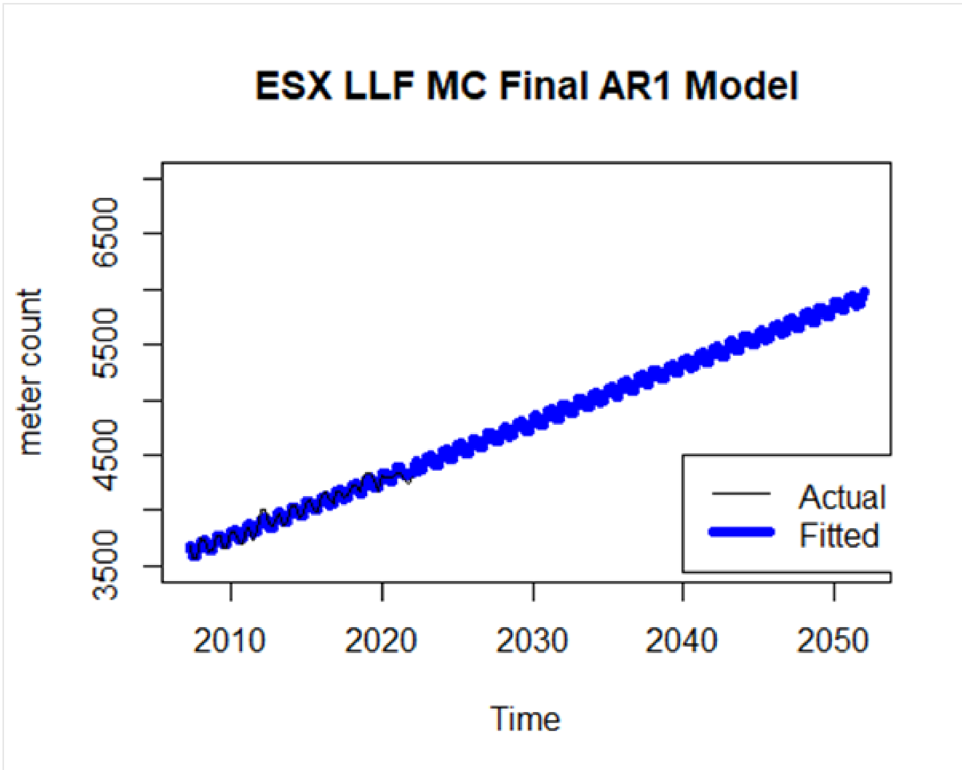


III.B.2.b.13 Essex Commercial / Industrial Low Load Factor (LLF) Meter Count Model

For its Essex Commercial / Industrial Low Load Factor meter count model, the Company developed a model using time, Q3 and Q4 indicator variables, and one indicator variable to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.97. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment. For this model:

- All predicted/actual 'pct error' < 3%.
- MAPE = 0.73%
- All four ex-post predicted values < 3.5% error,

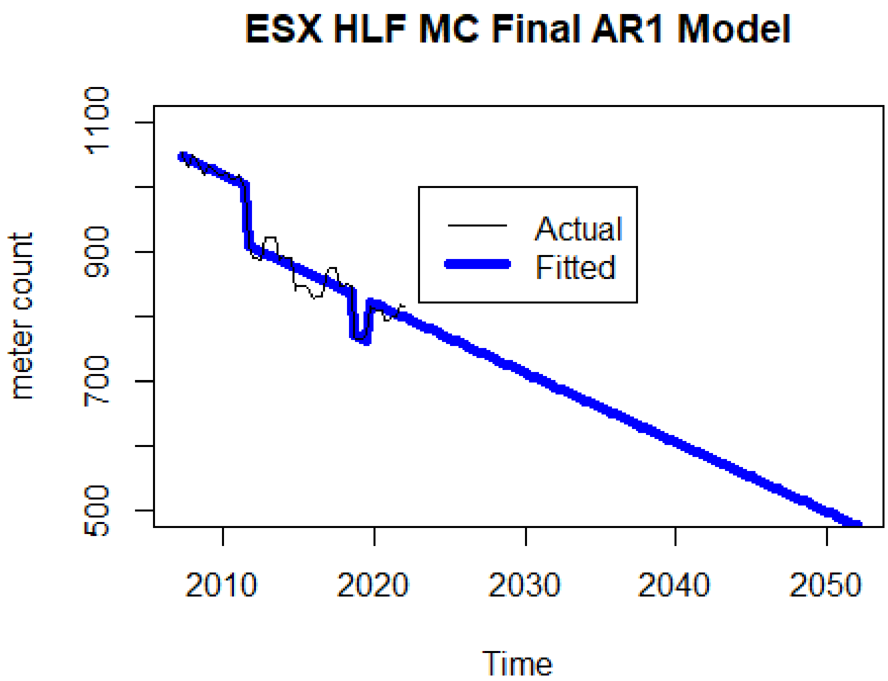
- All parameters in the ex-post change by less than 7%.



III.B.2.b.14 Essex Commercial / Industrial High Load Factor (HLF) Meter Count Model

For its Essex Commercial / Industrial High Load Factor meter count model, the Company developed a model using time and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.97. The residuals of the model were heteroscedastic, and the model passed the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment. For this model:

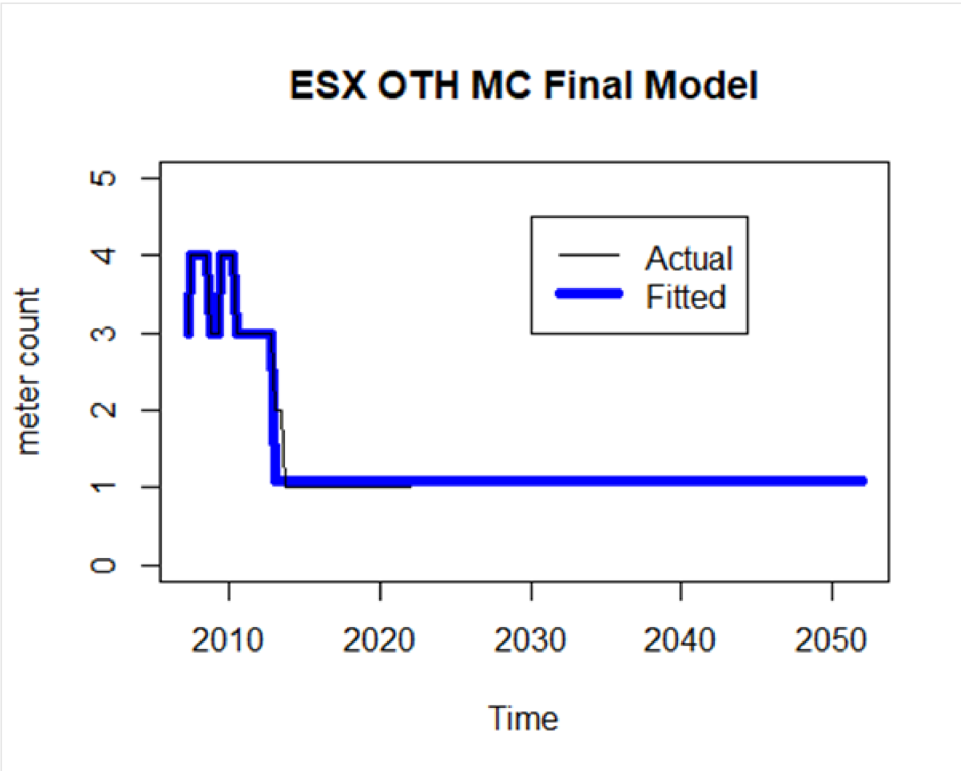
- All predicted/actual 'pct error' < 4.5%.
- MAPE = 1.38%
- All four ex-post predicted values < 3.5% error.
- All parameters in the ex-post change by less than 9%



III.B.2.b.15 Essex Other Meter Count Model

For its Essex Other meter count model, the Company developed a model using two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.97. The residuals of the model were homoscedastic, and the model failed the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals, but the Company did not pursue an AR(1) model. For this model:

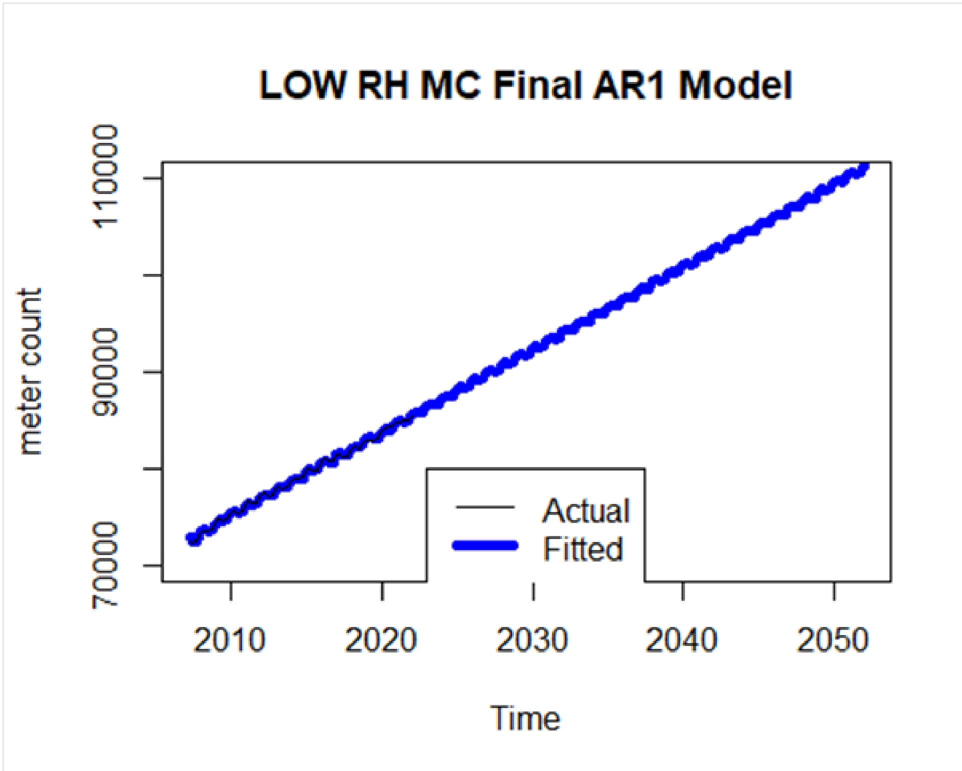
- All predicted/actual 'pct error' = 0%, except for three point.
- MAPE = 6.89%
- All four ex-post predicted values < 9% error.
- All parameters in the ex-post change by less than 1%



III.B.2.b.16 Colonial-Lowell Residential Heating Meter Count Model

For its Lowell Residential Heating meter count model, the Company developed a model using time, natural gas price, the Q3 and Q3 indicator variables, and one indicator variable to account for structural change in the data as the independent variables. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment. For this model:

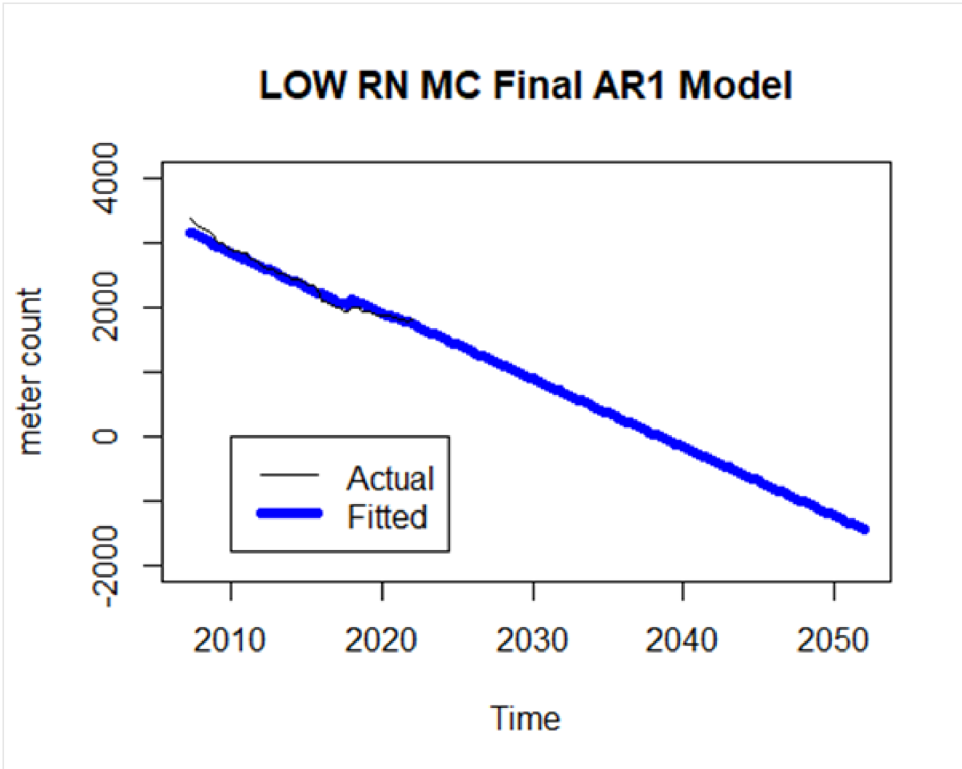
- All predicted/actual 'pct error' < 1%.
- MAPE = 0.16%
- All four ex-post predicted values < 0.3% error.
- All parameters in the ex-post change by less than 4%



III.B.2.b.17 Colonial-Lowell Residential Non-Heating Meter Count Model

For its Lowell Residential Non-Heating meter count model, the Company developed a model using time and two dummy variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment. For this model:

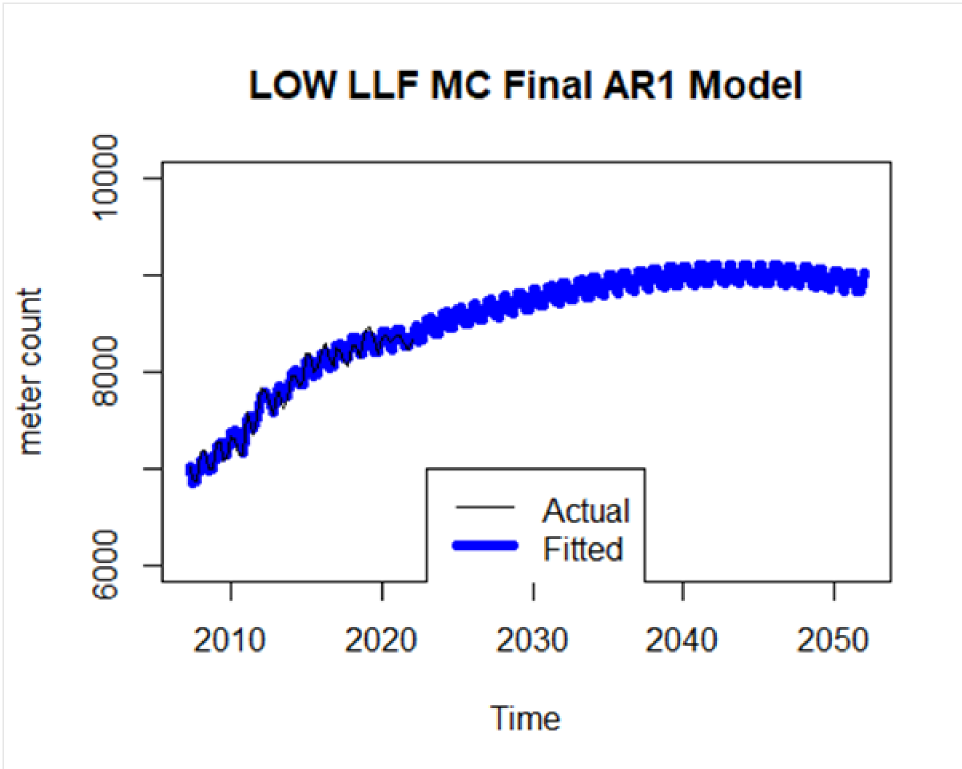
- All predicted/actual 'pct error' < 7%.
- MAPE = 2.98%
- All four ex-post predicted values < 8.5% error.
- All parameters in the ex-post change by less than 6.5%.



III.B.2.b.18 Colonial-Lowell Commercial / Industrial Low Load Factor (LLF) Meter Count Model

For its Lowell Commercial / Industrial Low Load Factor meter count model, the Company developed a model using population, two quarter dummies, and two dummy variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.98. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment. For this model:

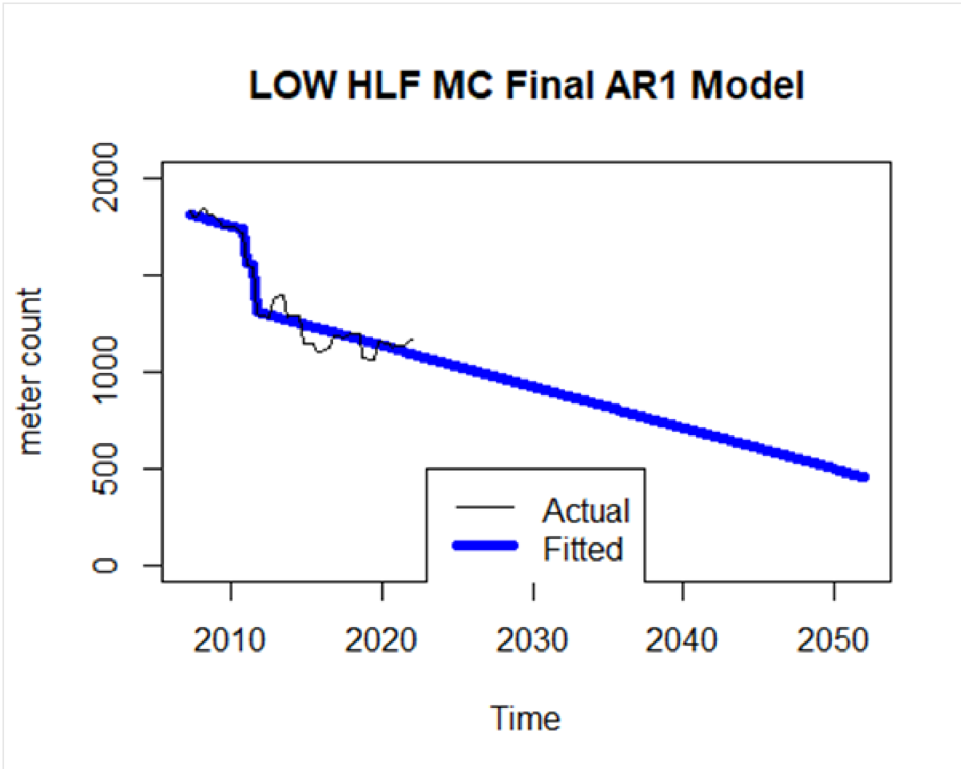
- All predicted/actual 'pct error' < 1.5%.
- MAPE = 0.63%
- All four AR1 ex-post predicted values < 0.8% error.
- All of the ex-post changes were less than 9.5%.



III.B.2.b.19 Colonial-Lowell Commercial / Industrial High Load Factor (HLF) Meter Count Model

For its Lowell Commercial / Industrial High Load Factor meter count model, the Company developed a model using time and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.96. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment. For this model:

- All predicted/actual 'pct error' < 10%.
- MAPE = 3.31%
- All four ex-post predicted values < 9.5% error.
- All parameters in the ex-post change by less than 16.2%.



III.B.2.b.20 Colonial-Lowell Other Meter Count Model

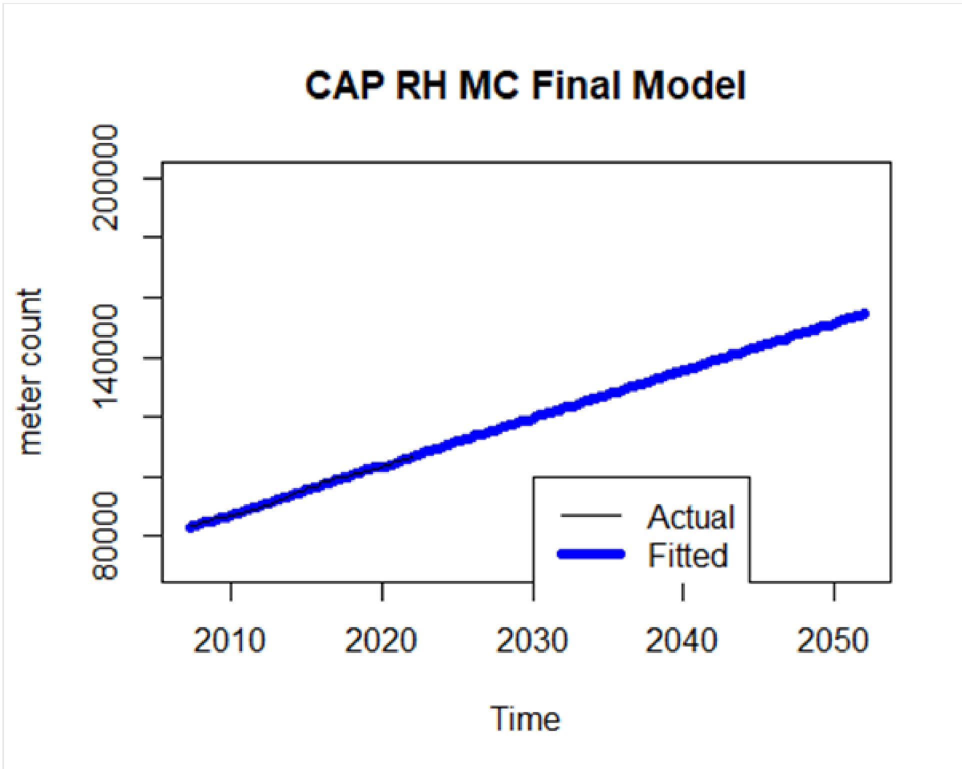
For its Lowell Other meter count model, the Company was unable to find a satisfactory model. The Company tested the various economic and price variables as possible drivers of the meter count for the Other rate group, but it was unable to develop a statistically acceptable model . Any of the possible equations violated the statistical tests the Company uses to develop its models (e.g. t-statistics were not greater than 2.0, ex-post analysis did not reliable predict the final values, etc.). It uses the most-recent observations for its forecast period.

III.B.2.b.21 Colonial-Cape Cod Residential Heating Meter Count Model

For its Cape Residential Heating meter count model, the Company developed a model using time, non-manufacturing employment, and the Q4 indicator variable. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, but the model did not pass the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment, however the Company did not use the AR model since it failed the ex-post parameters change test. For this model:

- All predicted/actual 'pct error' < 1.2%.
- MAPE = 0.39%
- All four ex-post predicted values < 0.4% error.

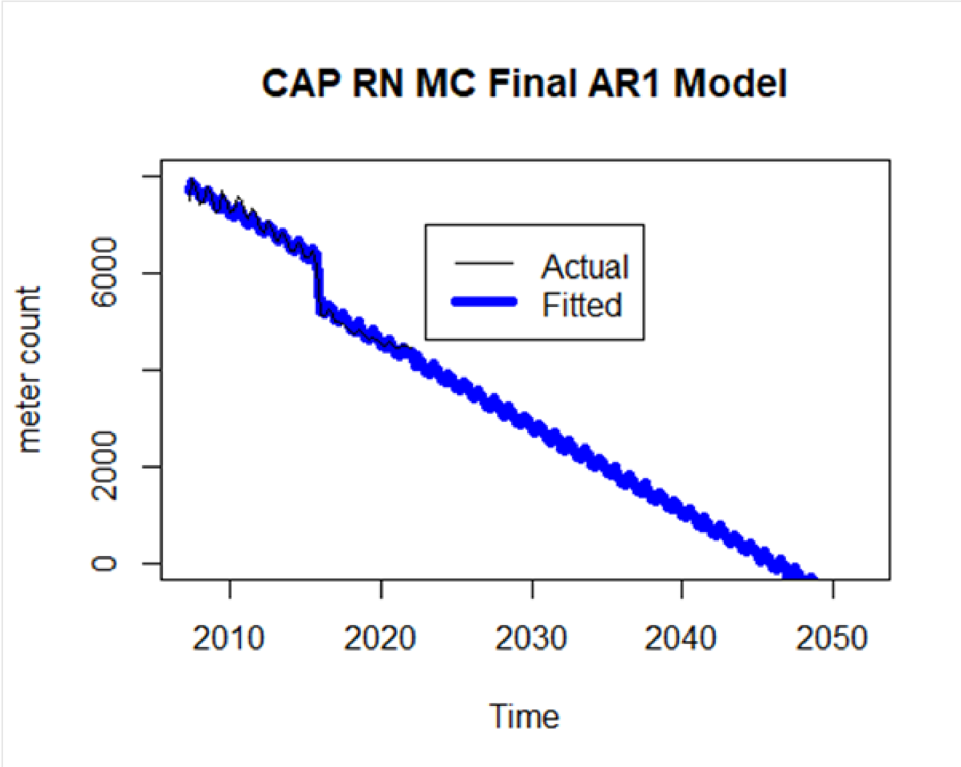
- All parameters in the ex-post change by less than 1.5%



III.B.2.b.22 Colonial-Cape Cod Residential Non-Heating Meter Count Model

For its Cape Residential Non-Heating meter count model, the Company developed a model using time, the Q3 and Q4 indicator variables, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, but the model did not pass the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment. For this model:

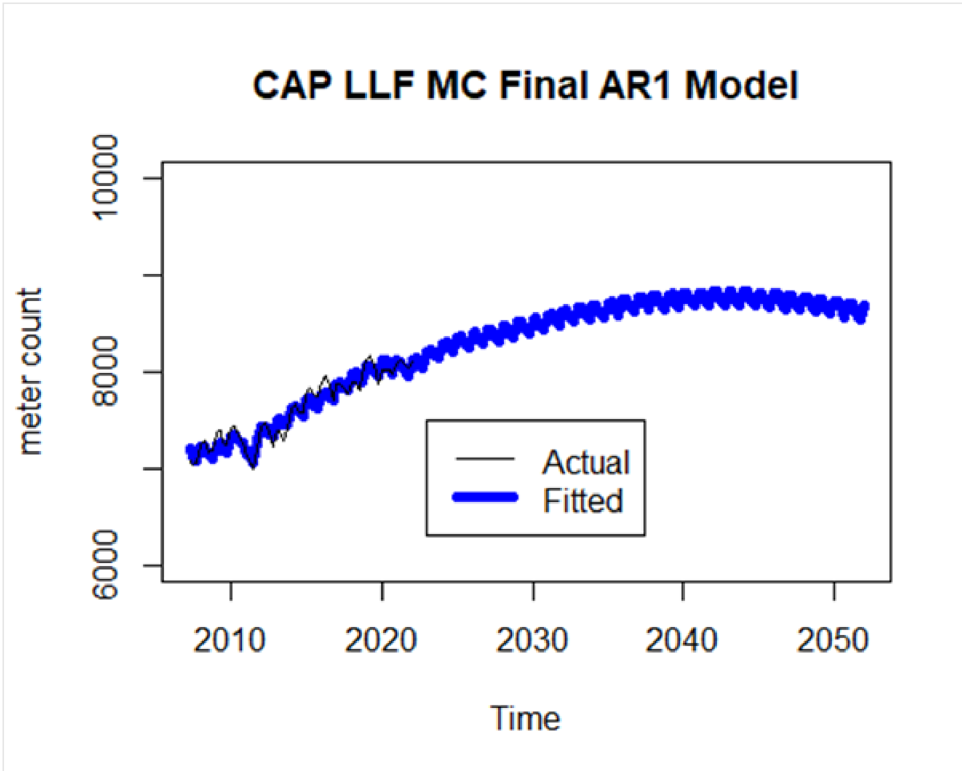
- All predicted/actual 'pct error' < 4.5%.
- MAPE = 1.36%
- All four AR1 ex-post predicted values < 8.5% error.
- All AR1 parameters in the ex-post change by less than 3%.



III.B.2.b.23 Colonial-Cape Cod Commercial / Industrial Low Load Factor (LLF) Meter Count Model

For its Cape Commercial / Industrial Low Load Factor meter count model, the Company developed a model using population, the Q3 and Q4 indicator variables, and one indicator variable to account for structural change in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.94. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment. For this model:

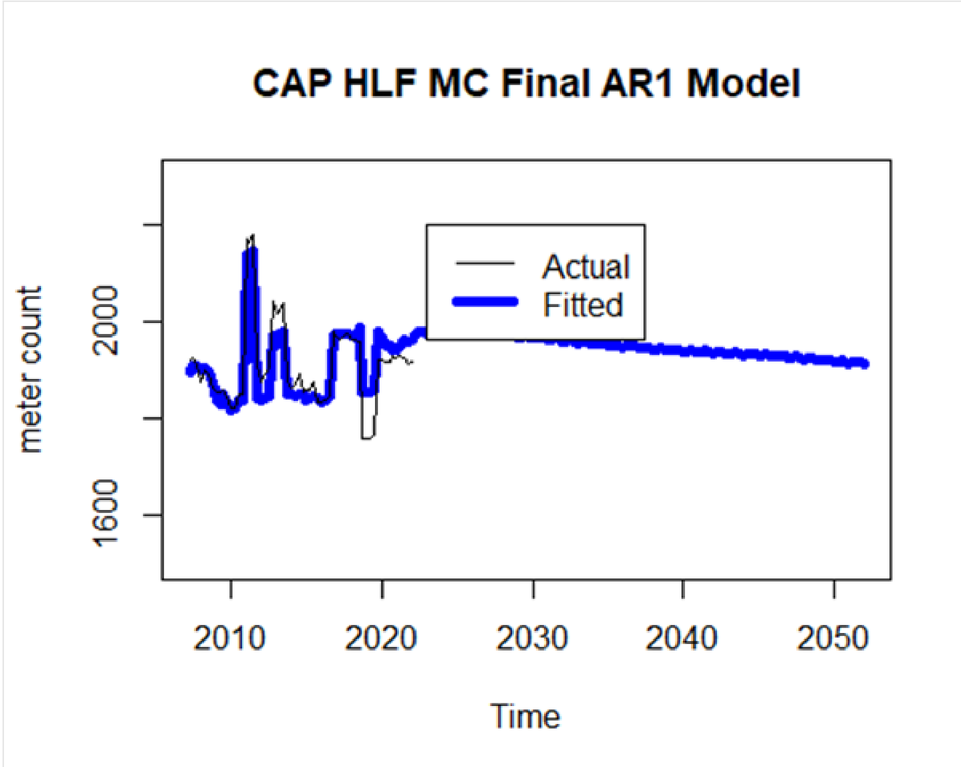
- All predicted/actual 'pct error' < 2.3%.
- MAPE = 0.86%
- All four ex-post predicted values < 1.0% error.
- All parameters in the ex-post change by less than 5.3%.



III.B.2.b.24 Colonial-Cape Cod Commercial / Industrial High Load Factor (HLF) Meter Count Model

For its Cape Commercial / Industrial High Load Factor meter count model, the Company developed a model using manufacturing employment and gas-oil price ratio, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.81. The residuals of the model were homoscedastic, but the model did not pass the Chow test for stability. This model did demonstrate AR(1) autocorrelation of its residuals. The Company re-ran the model to incorporate AR(1) adjustment. For this model:

- All predicted/actual 'pct error' < 5.6%.
- MAPE = 1.49%
- All four AR1 ex-post predicted values < 2.8% error.
- All AR1 parameters in the ex-post change by less than 6.5%.



III.B.2.b.25 Colonial-Cape Cod Other Meter Count Model

For its Cape Other meter count model, the Company was unable to find a satisfactory model. It uses the most-recent observations for its forecast period.

III.B.2.c. Use per Customer Models

For each of the Company's four divisions and for each of the five customer groups (Residential Heating, Residential Non-Heating, Commercial and Industrial Low-Load Factor, Commercial and Industrial High-Load Factor, and Other), the Company developed two use-per-customer models from its quarterly data: one for the peak period and one for the off-peak period. The Company used a quarterly value of 1,000 Heating Degree Days as the cutoff point to divide its data into peak and off-peak periods. Peak period uses-per-customer would include space heating usage, while off-peak period uses-per-customer would include minimal to no space heating usage.

While the modeling of the meter counts often required re-modeling to account for autocorrelation of the residuals, the Company found that the use-per-customer models do not reflect autocorrelation of the residuals.

III.B.2.c.1 Residential Heating -- Introduction

Residential Heating customers use natural gas for space heating purposes as well as other residential applications (e.g. cooking, hot water heating, clothes drying) hence use per customer displays a seasonal pattern, being positively correlated with degree days.

Economic theory suggests that, in addition, the Residential Heating use per customer may be positively correlated with such variables as measures of income or wealth (e.g. personal income, per capita personal income, employment levels).

Economic theory suggests that, in addition, the Residential Heating use per customer may be negatively correlated with the price of natural gas.

III.B.2.c.2 Residential Non-Heating -- Introduction

Residential Non-Heating customers use natural gas for only non-space heating purposes (e.g. cooking, hot water heating, clothes drying). While Residential Non-Heating use per customer displays a seasonal pattern, it should be lower than that of a Residential Heating customer and be positively correlated with degree days.

Economic theory suggests that, in addition, the Residential Non-Heating use per customer may be positively correlated with such variables as measures of income or wealth (e.g. personal income, per capita personal income, employment levels).

Economic theory suggests that, in addition, the Residential Non-Heating use per customer may be negatively correlated with the price of natural gas.

III.B.2.c.3 Commercial / Industrial Low Load Factor (LLF) -- Introduction

Commercial / Industrial Low Load Factor customers use natural gas for space heating purposes as well as other commercial applications (e.g. cooking, hot water heating) hence use per customer displays a seasonal pattern, being positively correlated with degree days.

Economic theory suggests that, in addition, the Commercial / Industrial Low Load Factor use per customer may be positively correlated with measures of income or wealth (e.g. GDP, employment levels, retail sales).

Economic theory suggests that, in addition, the Commercial / Industrial Low Load Factor use per customer may be negatively correlated with the price of natural gas.

III.B.2.c.4 Commercial / Industrial High Load Factor (HLF) -- Introduction

Commercial / Industrial High Load Factor customers use natural gas for commercial applications (e.g. process loads, cooking, hot water heating) but they could also use natural gas for space heating purposes as well as hence use per customer could display a seasonal pattern and be positively correlated with degree days.

Economic theory suggests that, in addition, the Commercial / Industrial High Load Factor use per customer may be positively correlated with measures of income or wealth (e.g. GDP, employment levels, retail sales).

Economic theory suggests that, in addition, the Commercial / Industrial High Load Factor use per customer may be negatively correlated with the price of natural gas.

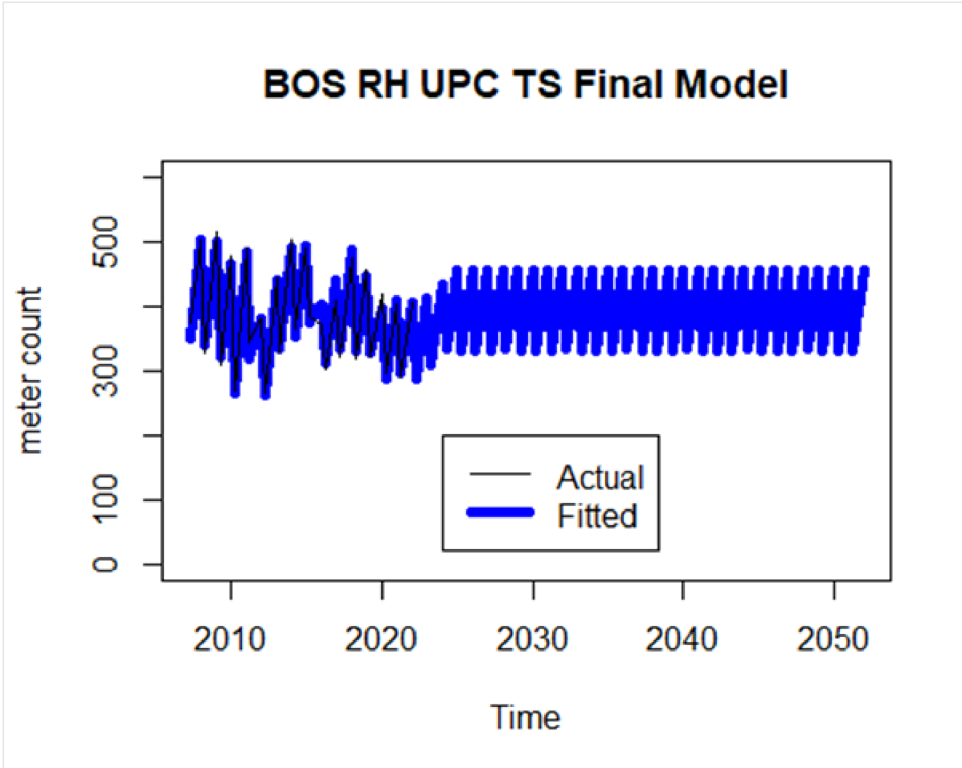
III.B.2.c.5 Other – Introduction

Other customers will tend to follow the usage patterns of the High-Load Factor customers so the Company used the same economic concepts as it used for the HLF customers (see Section III.B.2.c.4) in modeling the Other customers.

III.B.2.c.6 Boston Residential Heating Use per Customer Model

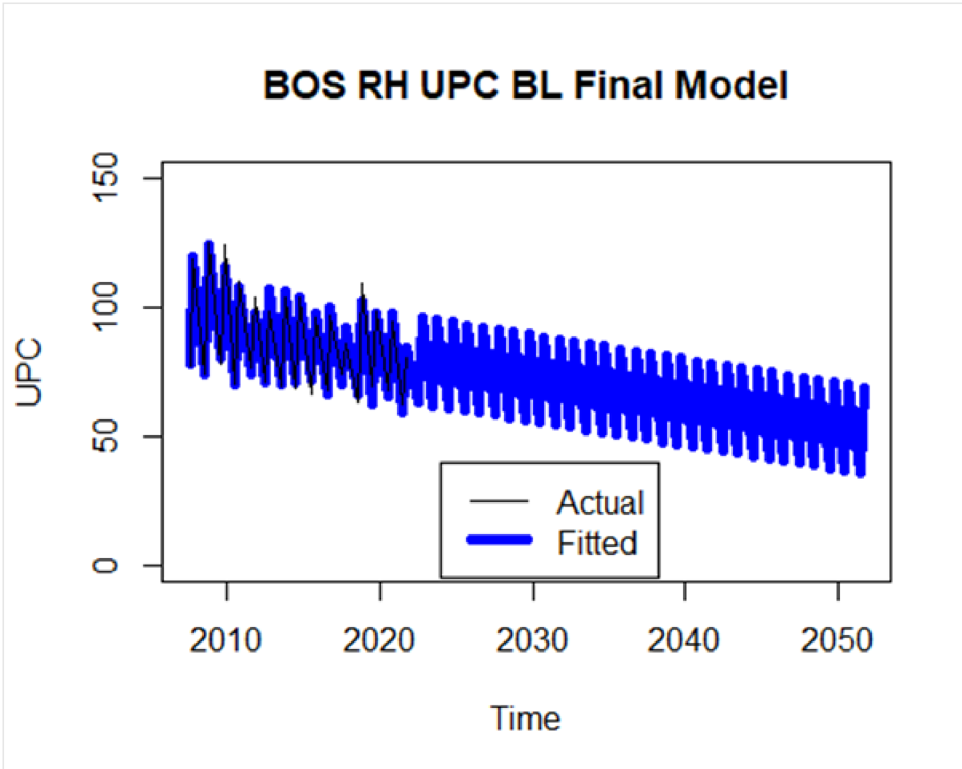
For its Boston Residential Heating use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD), Q2 dummy variable, and two dummy variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 8%.
- MAPE = 2.95%
- The ex-post predicted values < 3% error,
- All parameters in the ex-post change by less than 2%.



For its Boston Residential Heating use-per-customer model of the off-peak period, the Company developed a model using BDD and time, and one dummy variable to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.95. The residuals of the model were homoscedastic and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

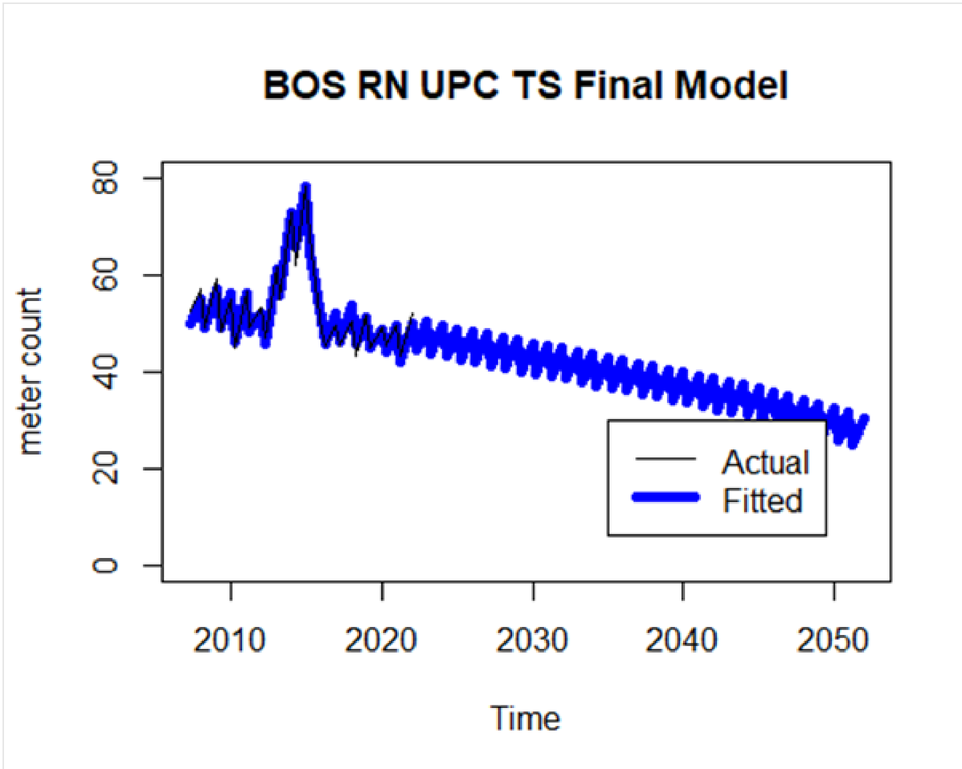
- All predicted/actual 'pct error' < 7.7%.
- MAPE = 3.48%
- The ex-post predicted values were < 5 % error,
- All parameters in the ex-post change by less than 2.2%.



III.B.2.c.7 Boston Residential Non-Heating Use per Customer Model

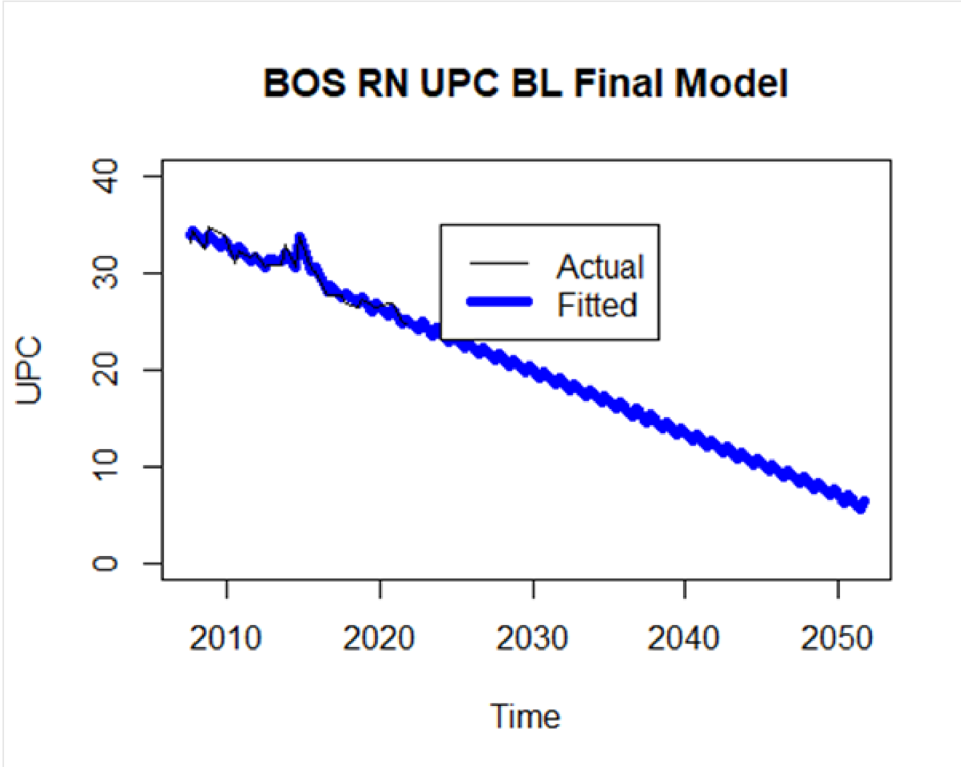
For its Boston Residential Non-Heating use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD) and per-capita personal income, and two dummy variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.95. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 6.6%.
- MAPE = 2.50%
- All ex-post predicted values were < 5.3% error
- All parameters in the ex-post change by less than 12.6%.



For its Boston Residential Non-Heating use-per-customer model of the off-peak period, the Company developed a model using billing degree days (BDD), time, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.95. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

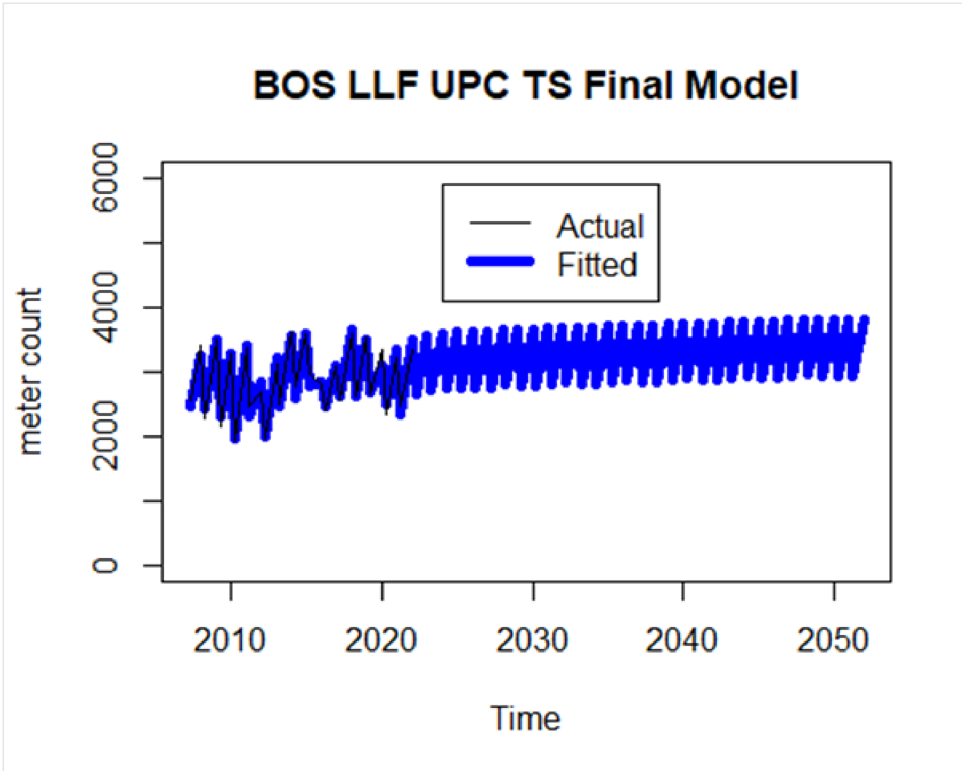
- All predicted/actual 'pct error' < 3.7 %.
- MAPE = 1.74%
- The ex-post predicted values were < 2% error,
- All parameters in the ex-post change by less than 2.8%.



III.B.2.c.8 Boston Commercial / Industrial Low Load Factor (LLF) Use per Customer Model

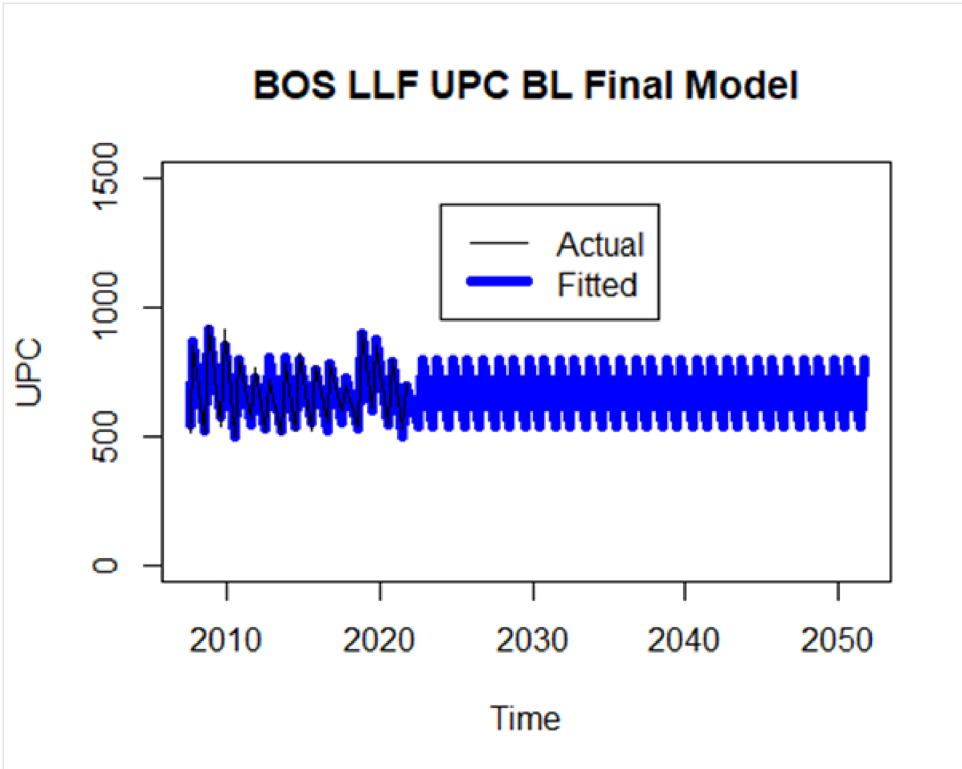
For its Boston Commercial / Industrial Low Load Factor use-per-customer model of the peak period, the Company developed a model using retail sales and billing degree days (BDD) and non-manufacturing employment, and one indicator variable to account for structural change in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.95. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 7.0%.
- MAPE = 3.14%
- The ex-post predicted values were < 5.6%,
- All parameters in the ex-post change by less than 11%.



For its Boston Commercial / Industrial Low Load Factor use-per-customer model of the off-peak period, the Company developed a model using billing degree days (BDD), and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0, except for the intercept, and the adjusted r-squared value was 0.95. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

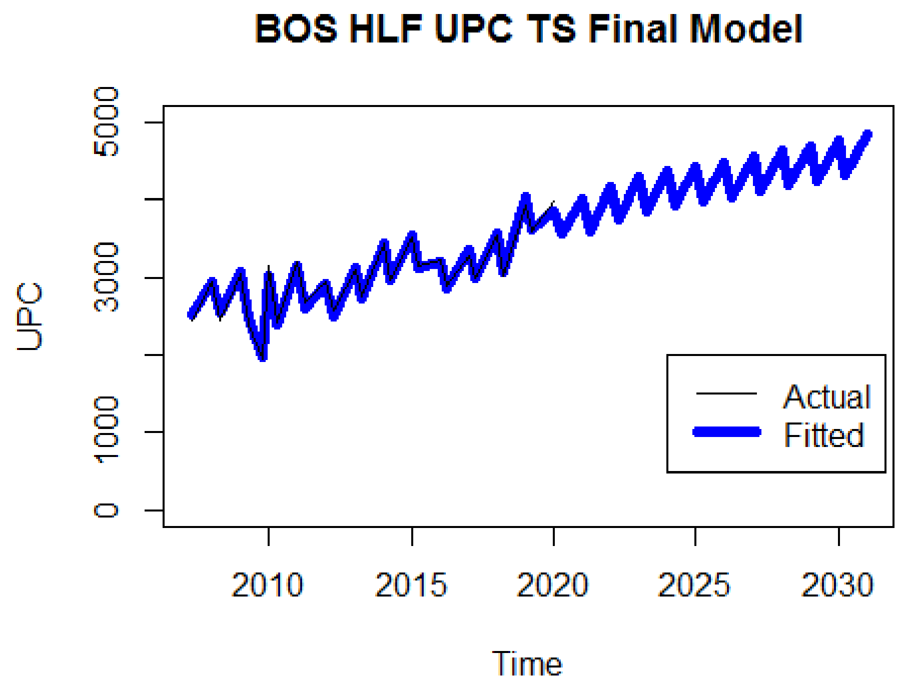
- All predicted/actual 'pct error' < 12.4%
- MAPE = 0.03445664
- All ex-post predicted values were < 5.8 % error,
- All parameters in the ex-post change by less than 1.1%.



III.B.2.c.9 Boston Commercial / Industrial High Load Factor (HLF) Use per Customer Model

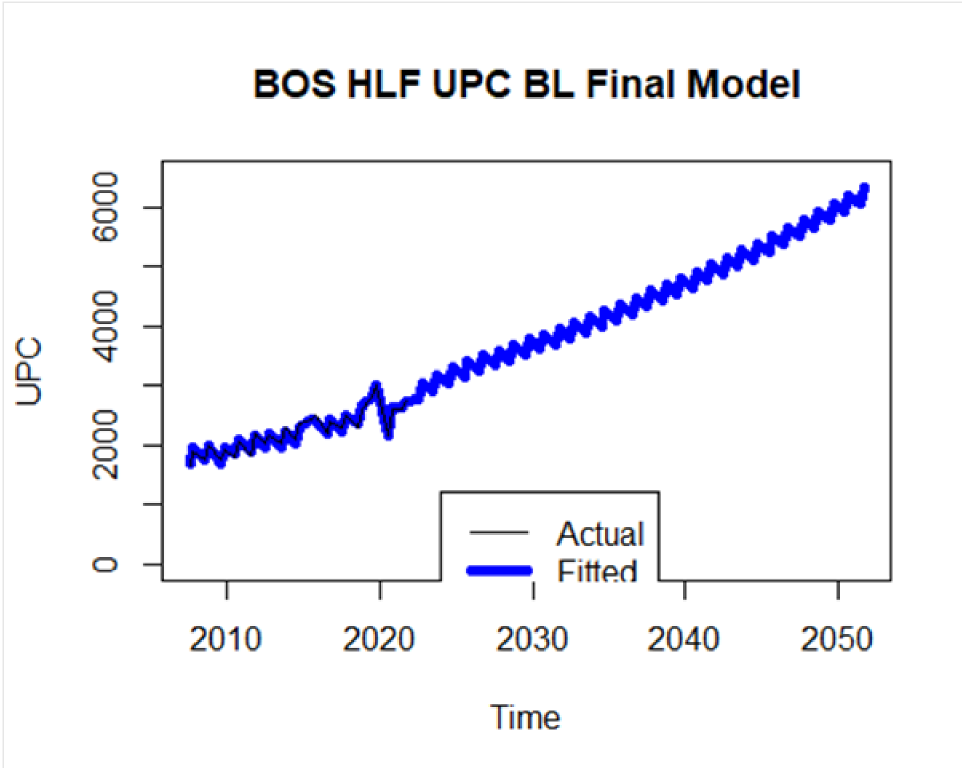
For its Boston Commercial / Industrial High Load Factor use-per-customer model of the peak period, the Company developed a model using GDP and billing degree days (BDD), and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 except for the intercept and the adjusted r-squared value was 0.98. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' 3.9%.
- MAPE = 1.63%
- All ex-post predicted values < 4.9% error,
- All parameters in the ex-post change by less than 6.2% except for the intercept.



For its Boston Commercial / Industrial Low Load Factor use-per-customer model of the off-peak period, the Company developed a model using GDP, Q4 indicator, and one indicator variable to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.97. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' 4.4%.
- MAPE = 2.04%
- All ex-post predicted values < 2.8% error,
- All parameters in the ex-post change by less than 8.2%.



III.B.2.c.10 Boston Other Use per Customer Model

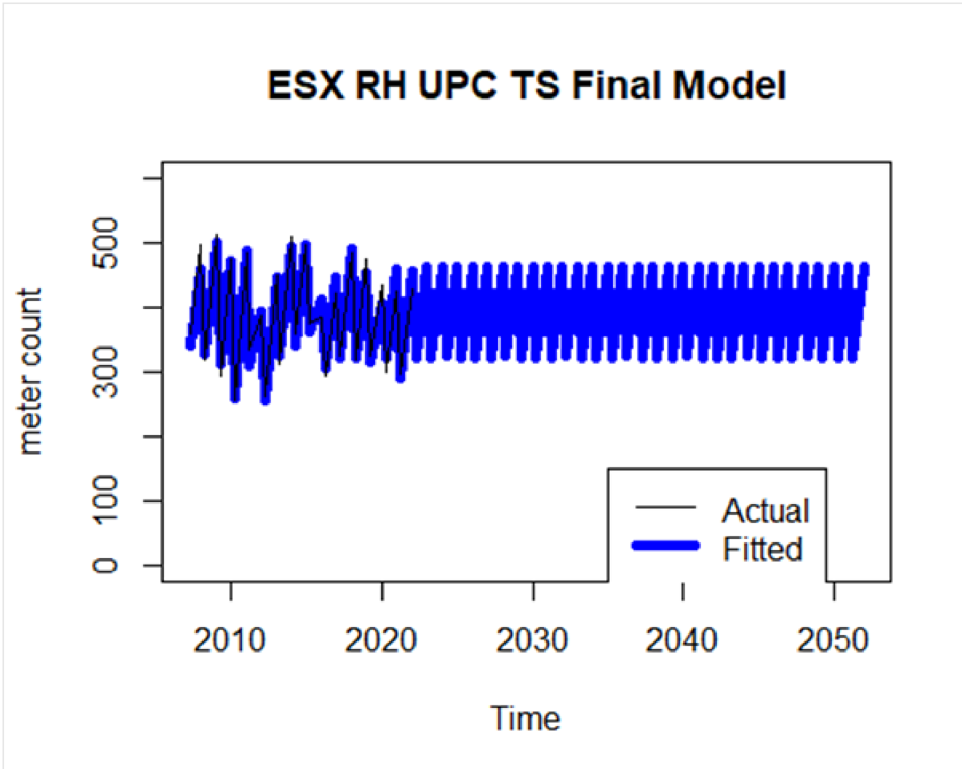
For its Boston Other use-per-customer model of the peak period, the Company was unable to find a satisfactory model. It uses the most-recent observations for its forecast period.

For its Boston Other use-per-customer model of the off-peak period, the Company was unable to find a satisfactory model. It uses the most-recent observations for its forecast period.

III.B.2.c.11 Essex Residential Heating Use per Customer Model

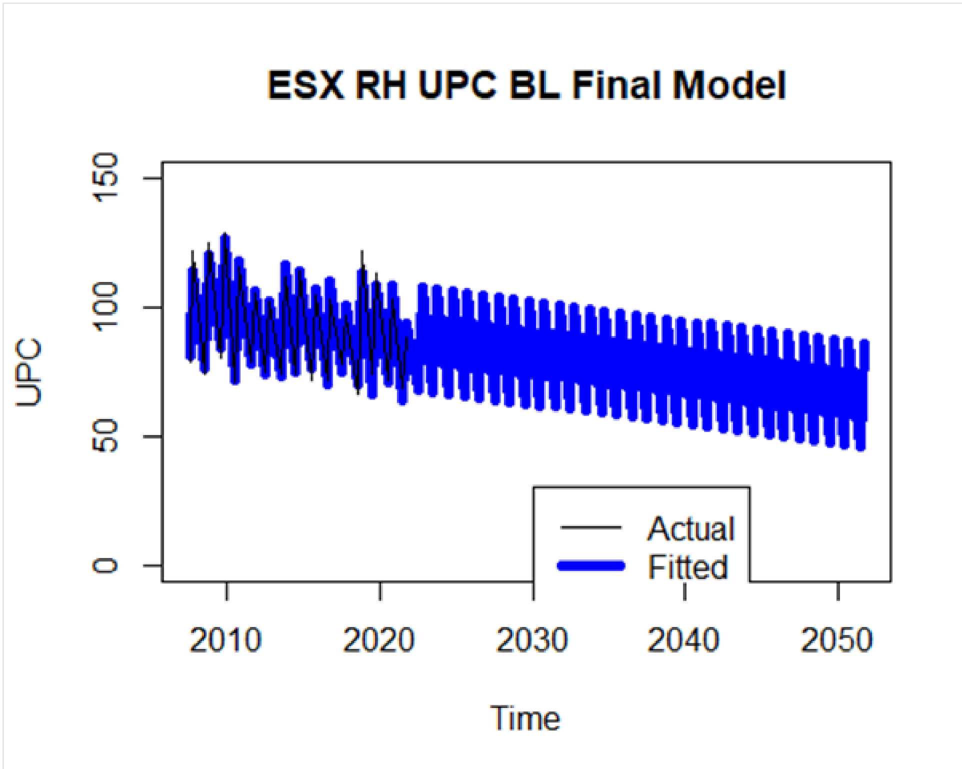
For its Essex Residential Heating use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD). The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.95. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 8.1%.
- MAPE = 3.69%
- The ex-post predicted values < 6.6% error,
- All parameters in the ex-post change by less than 15%.



For its Essex Residential Heating use-per-customer model of the off-peak period, the Company developed a model using billing degree days (BDD) and time, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.95. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

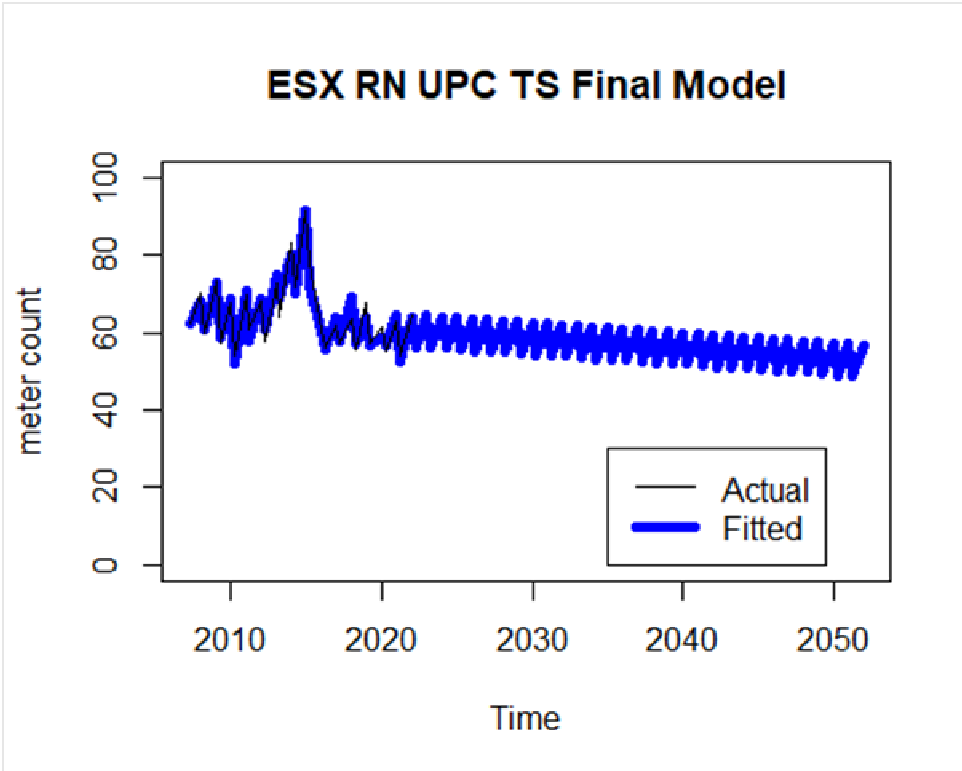
- All predicted/actual 'pct error' 10.5%.
- MAPE = 3.63%
- The ex-post predicted values < 8.3% error,
- All parameters in the ex-post change by less than 2.2%.



III.B.2.c.12 Essex Residential Non-Heating Use per Customer Model

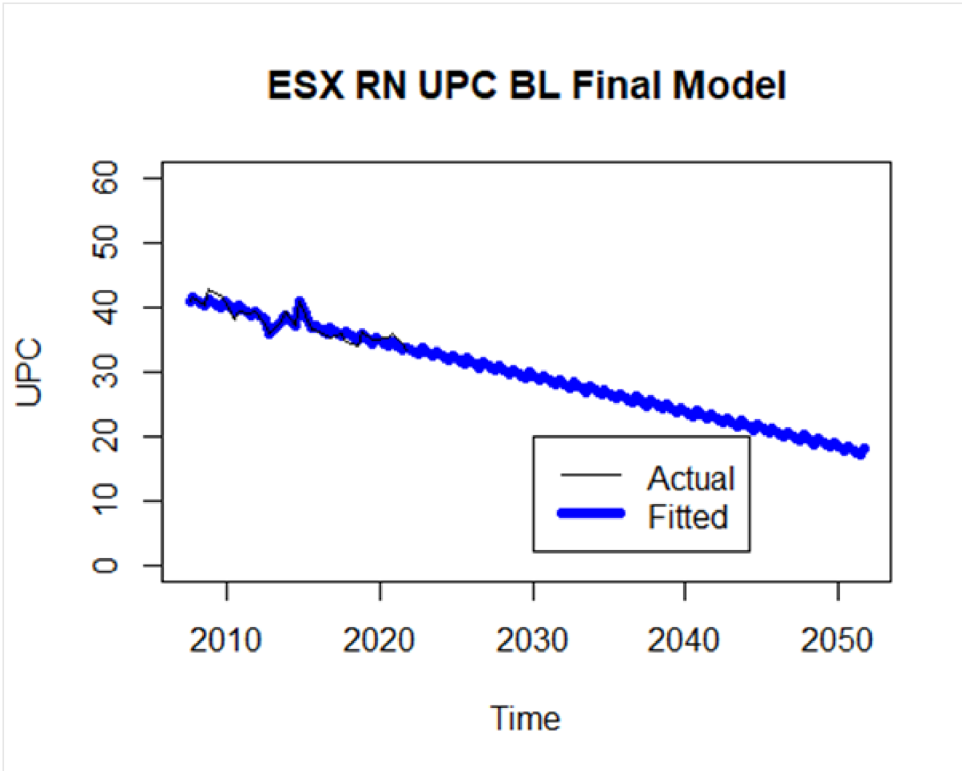
For its Essex Residential Non-Heating use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD) and time, the Q2 indicator variable, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.91. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 8.8%.
- MAPE = 2.89%
- All ex-post predicted value < 3.1% error
- All parameters in the ex-post change by less than 10.5%.



For its Essex Residential Non-Heating use-per-customer model of the off-peak period, the Company developed a model using time, billing degree days (BDD), and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.88. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

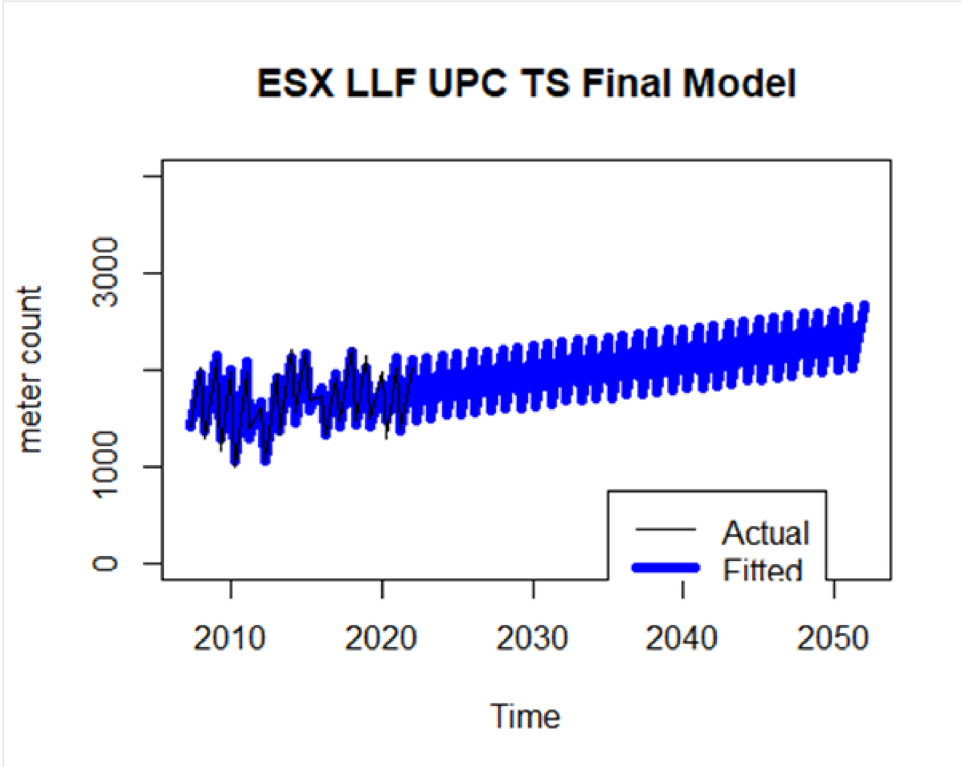
- All predicted/actual 'pct error' < 4.3%.
- MAPE = 1.71%
- The ex-post predicted values < 3.1% error,
- All parameters in the ex-post change by less than 9.1%.



III.B.2.c.13 Essex Commercial / Industrial Low Load Factor (LLF) Use per Customer Model

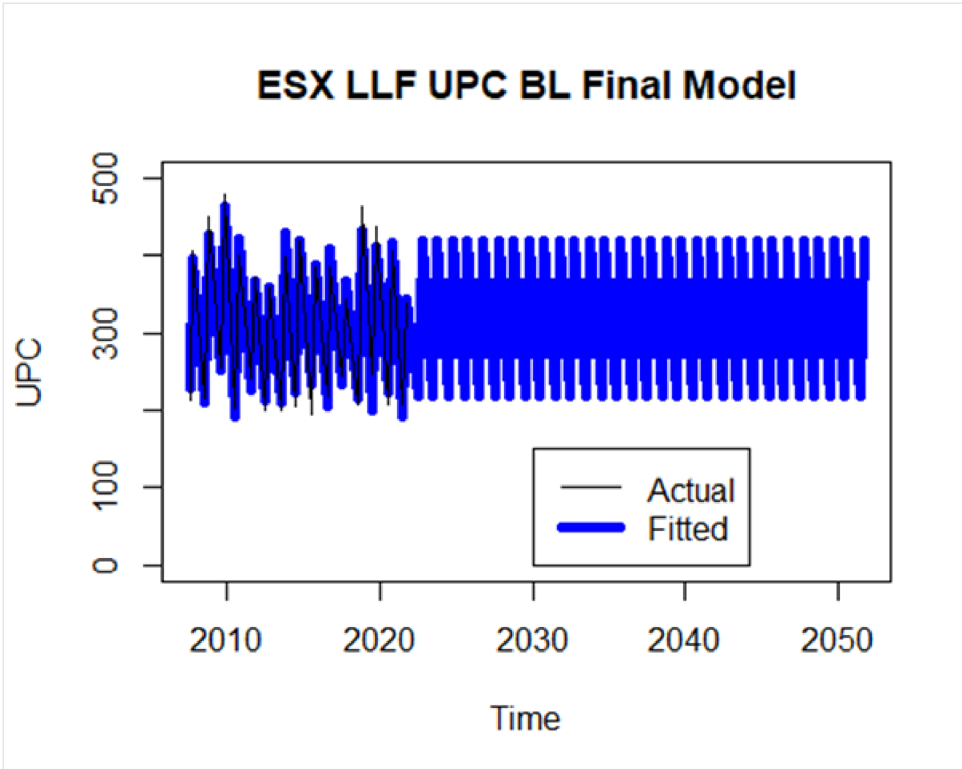
For its Essex Commercial / Industrial Low Load Factor use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD) and personal income. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.94. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' 14%.
- MAPE = 4.33%
- The ex-post predicted values < 3.7% error,
- All parameters in the ex-post change by less than 7.5%.



For its Essex Commercial / Industrial Low Load Factor use-per-customer model of the off-peak period, the Company developed a model using billing degree days (BDD) and one dummy variable to account for structural change in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.96. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

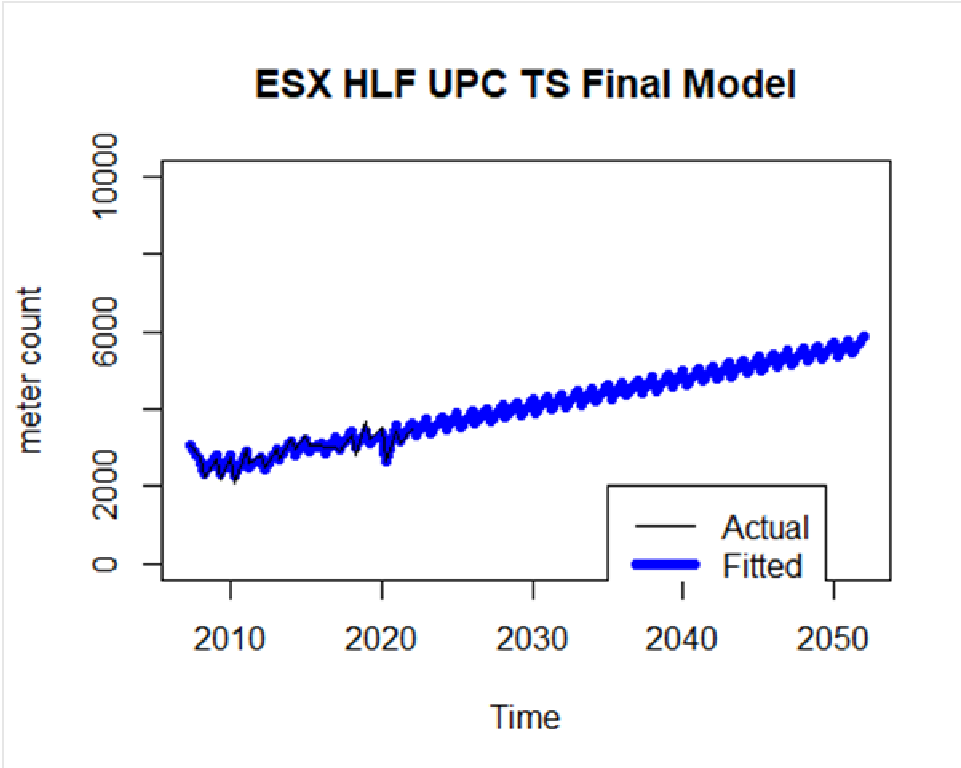
- All predicted/actual 'pct error' < 9%, except one point (2015.50, -20.05% and 2019.50, 18.61%).
- MAPE = 5.50%
- The ex-post predicted values < 8.5% error,
- All parameters in the ex-post change by less than 1.0%.



III.B.2.c.13 Essex Commercial / Industrial High Load Factor (HLF) Use per Customer Model

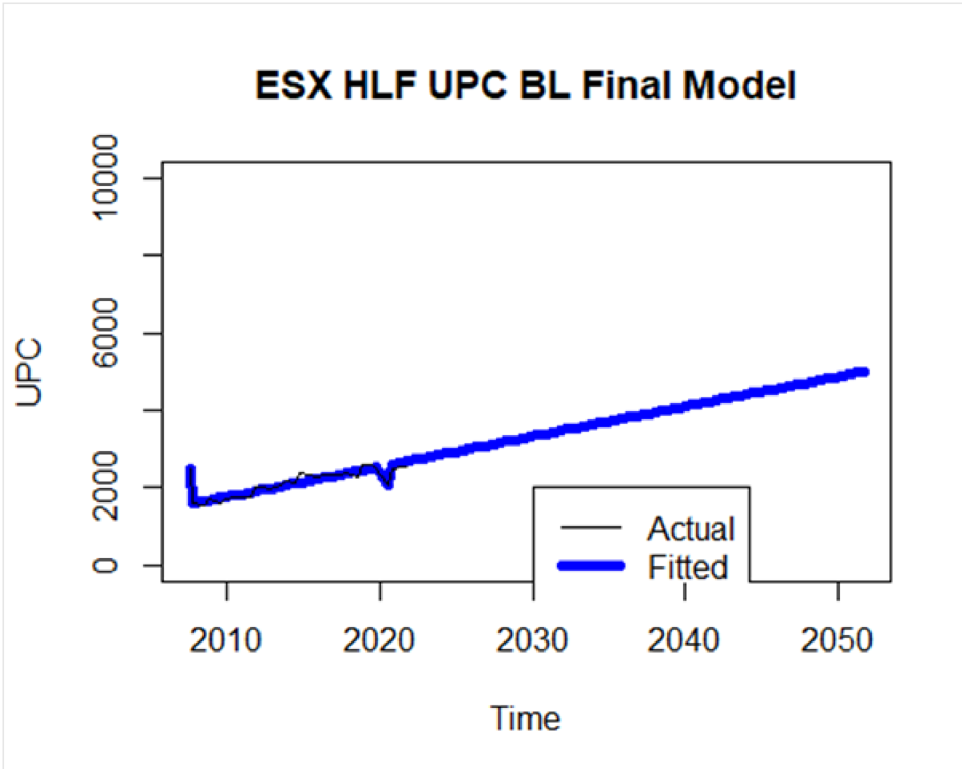
For its Essex Commercial / Industrial High Load Factor use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD) and time, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.87. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' 9.6%.
- MAPE = 3.66%
- The ex-post predicted values < 5.9% error,
- All parameters in the ex-post change by less than 6.1%.



For its Essex Commercial / Industrial High Load Factor use-per-customer model of the off-peak period, the Company developed a model using time, and two dummy variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.90. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' 10.8%.
- MAPE = 3.61%
- The ex-post predicted values < 6.7%% error,
- All parameters in the ex-post change by less than 7.6%.



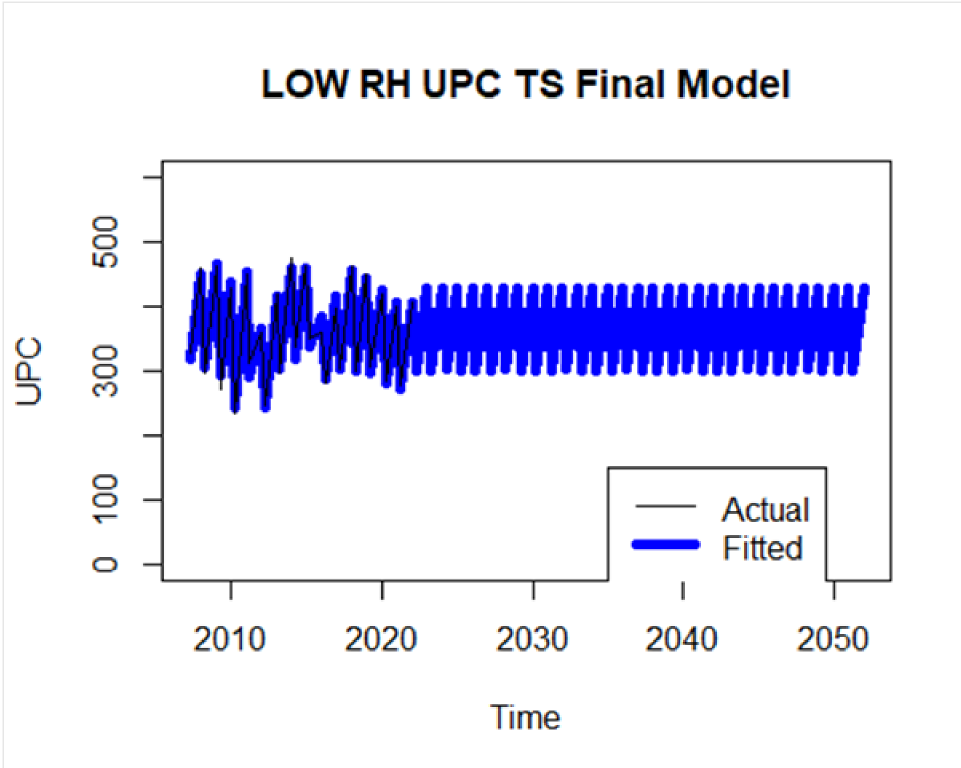
III.B.2.c.14 Essex Other Use per Customer Model

For its Essex Other use-per-customer model of the peak period, the Company was unable to find a satisfactory model. It uses the most-recent observations for its forecast period.

III.B.2.c.15 Colonial-Lowell Residential Heating Use per Customer Model

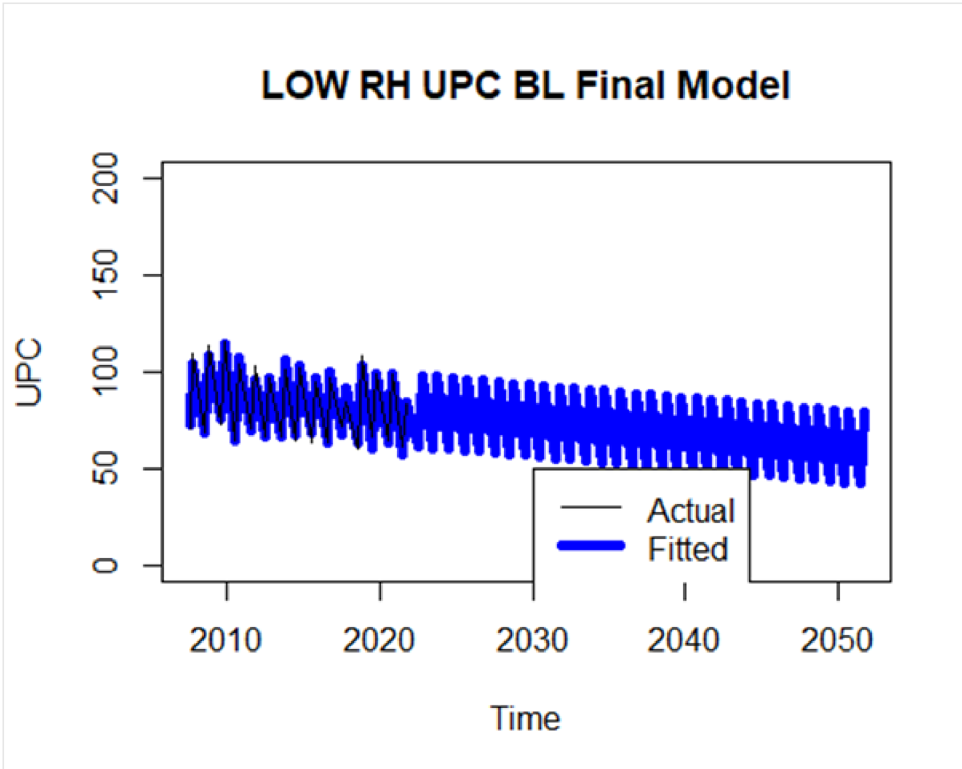
For its Lowell Residential Heating use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD), and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.98. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 7.8%.
- MAPE = 2.55%
- The ex-post predicted values < 2.1% error,
- All parameters in the ex-post change by less than 6.0%.



For its Lowell Residential Heating use-per-customer model of the off-peak period, the Company developed a model using billing degree days (BDD) and time, and one indicator variable to account for structural change in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.96. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

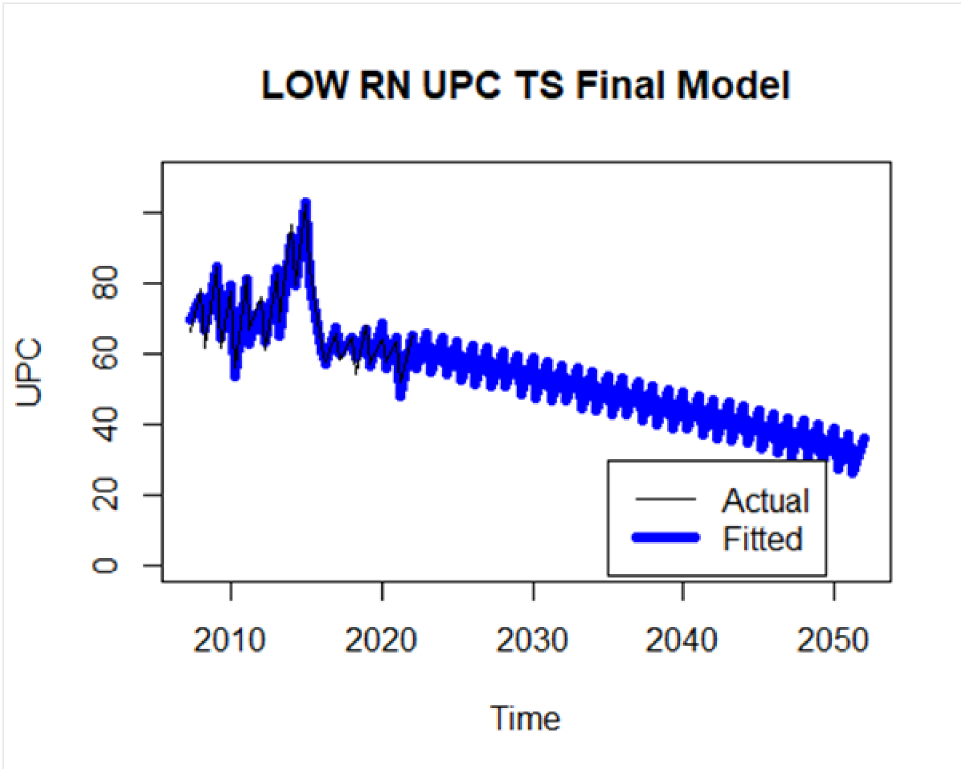
- All predicted/actual 'pct error' < 10.2%.
- MAPE = 3.39%
- All ex-post predicted values < 7.9%
- All parameters in the ex-post change by less than 5.1%.



III.B.2.c.16 Colonial-Lowell Residential Non-Heating Use per Customer Model

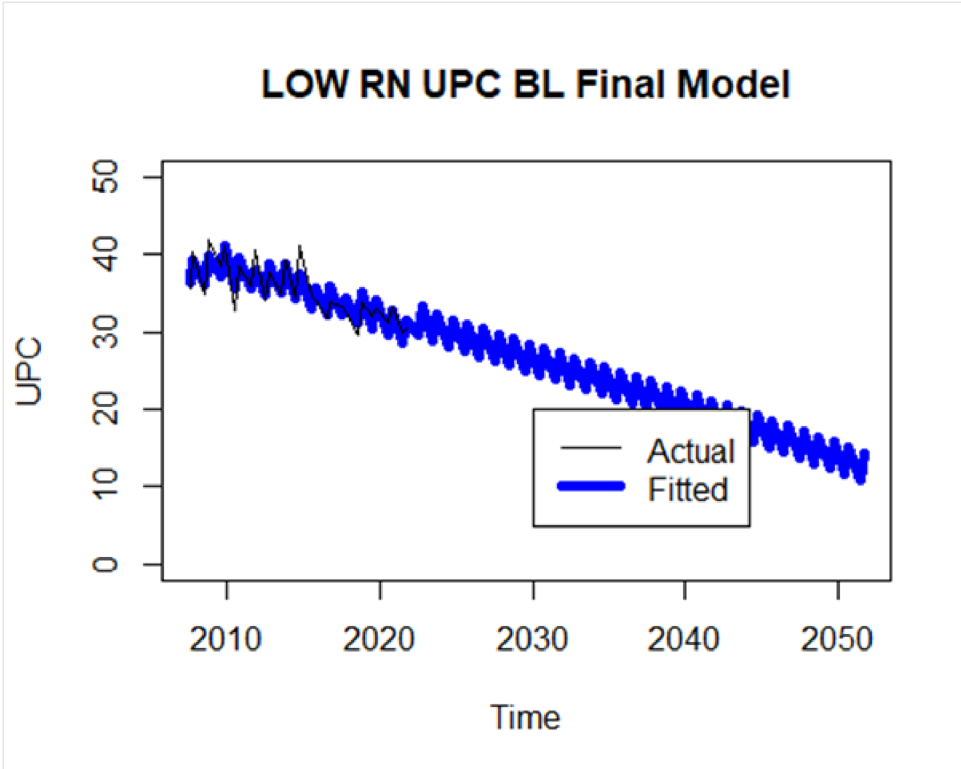
For its Lowell Residential Non-Heating use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD) and personal income, the Q2 dummy, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.95. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 8.6%.
- MAPE = 3.19%
- All ex-post predicted values were < 9.7 %,
- All parameters in the ex-post change by less than 7.4%.



For its Lowell Residential Non-Heating use-per-customer model of the off-peak period, the Company developed a model using BDD and personal income for the Lowell territory. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.80. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

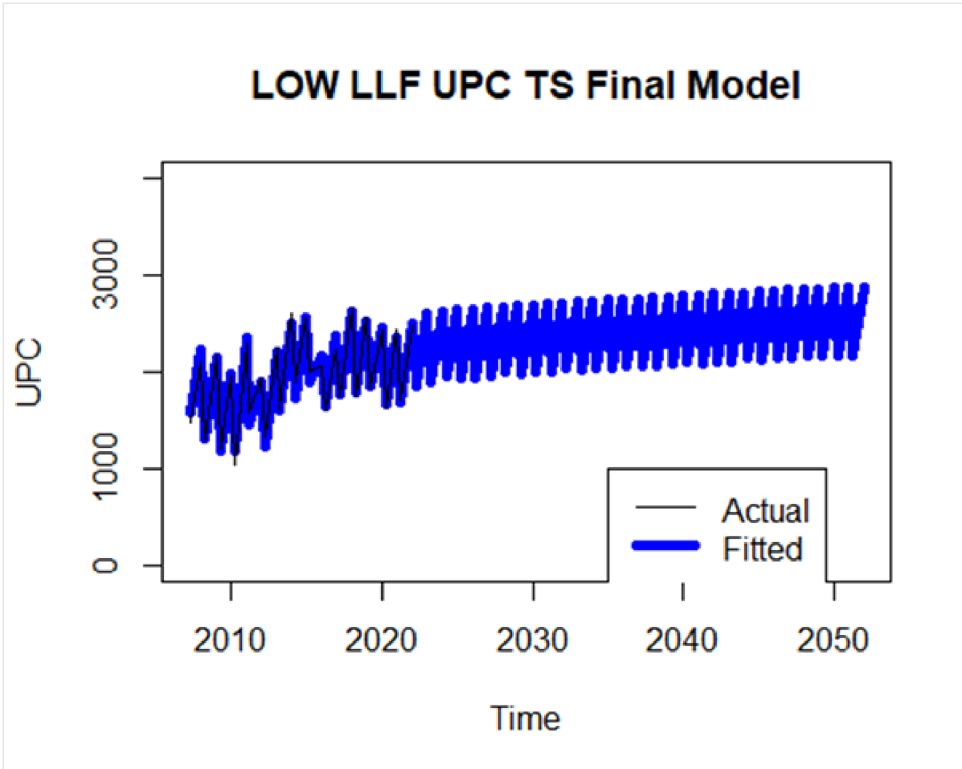
- All predicted/actual 'pct error' 8.8%.
- MAPE = 3.64%
- All ex-post predicted values < 8.7% error.
- All parameters in the ex-post change by less than 3.8%.



III.B.2.c.17 Colonial-Lowell Commercial / Industrial Low Load Factor (LLF) Use per Customer Model

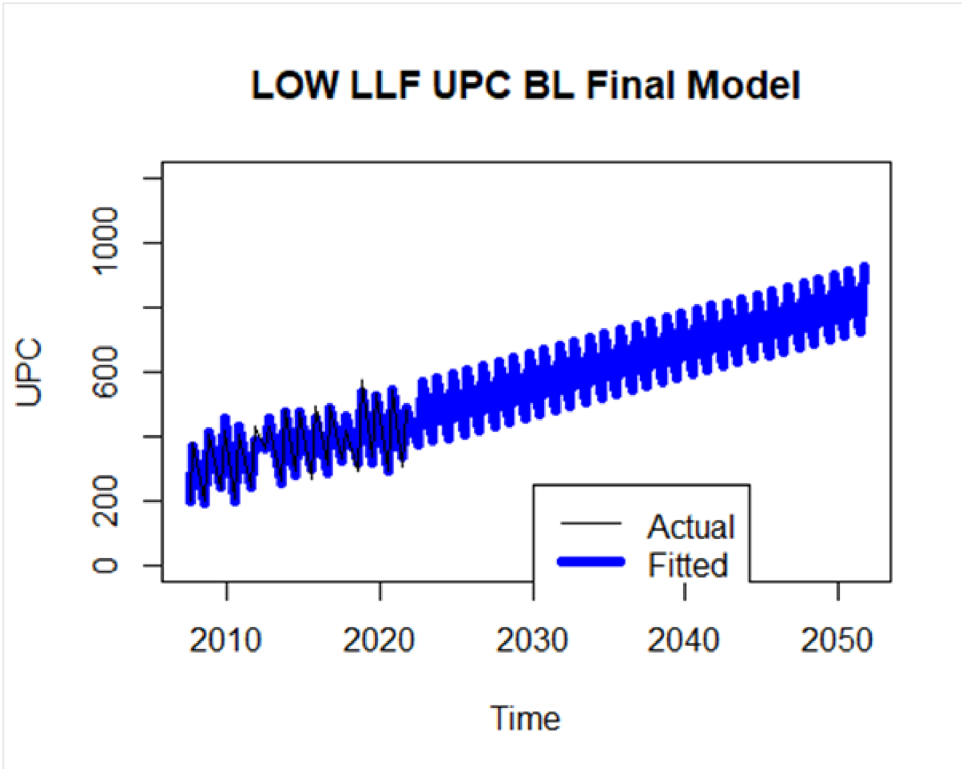
For its Lowell Commercial / Industrial Low Load Factor use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD) and non-manufacturing employment, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.96. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All but two predicted/actual 'pct error' < 14.3%.
- MAPE = 3.5%
- All ex-post predicted values < 1.8% error.
- All parameters in the ex-post change by less than 5.2%.



For its Lowell Commercial / Industrial Low Load Factor use-per-customer model of the off-peak period, the Company developed a model using billing degree days (BDD) and time, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.95. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

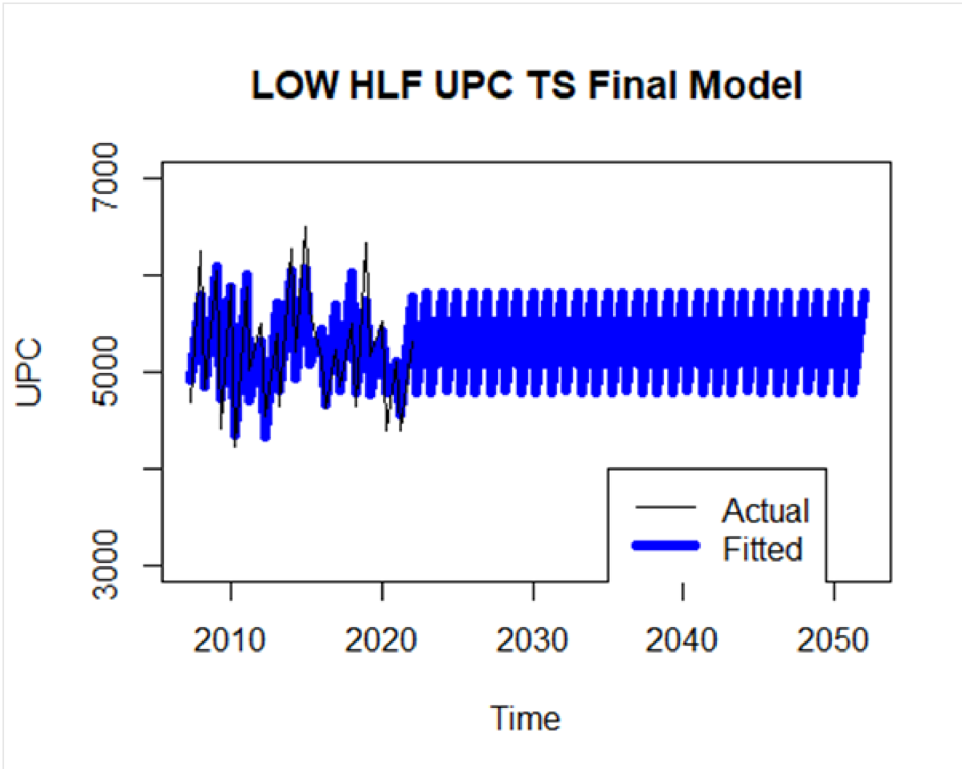
- All predicted/actual 'pct error' < 12.3%
- MAPE = 4.28%
- All ex-post predicted values < 11.1% error
- All parameters in the ex-post change by less than 10.6%.



III.B.2.c.18 Colonial-Lowell Commercial / Industrial High Load Factor (HLF) Use per Customer Model

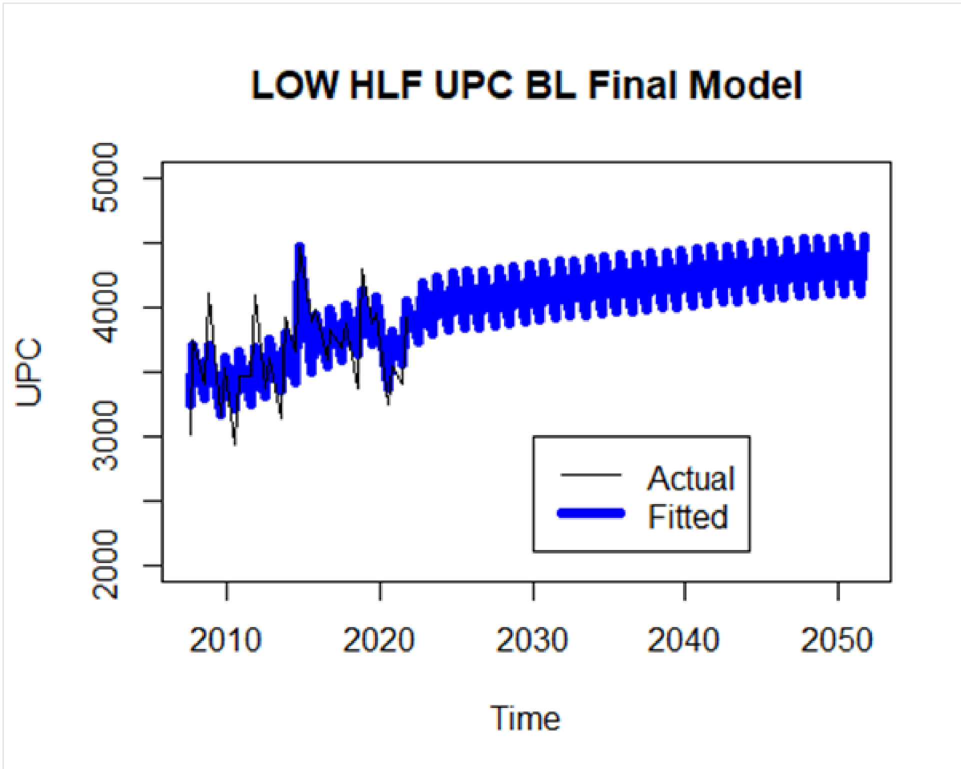
For its Lowell Commercial / Industrial High Load Factor use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD) and one indicator variables to account for structural change in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.75. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 9.7%.
- MAPE = 4.82%
- All ex-post predicted values < 8.4% error,
- All parameters in the ex-post change by less than 4.3%.



For its Lowell Commercial / Industrial High Load Factor use-per-customer model of the off-peak period, the Company developed a model using employment for the Lowell territory, the Q4 indicator, and one indicator variable to account for structural change in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 10.1%.
- MAPE = 4.68%
- All ex-post predicted values < 4.9% error
- All parameters in the ex-post change by less than 1.7%.



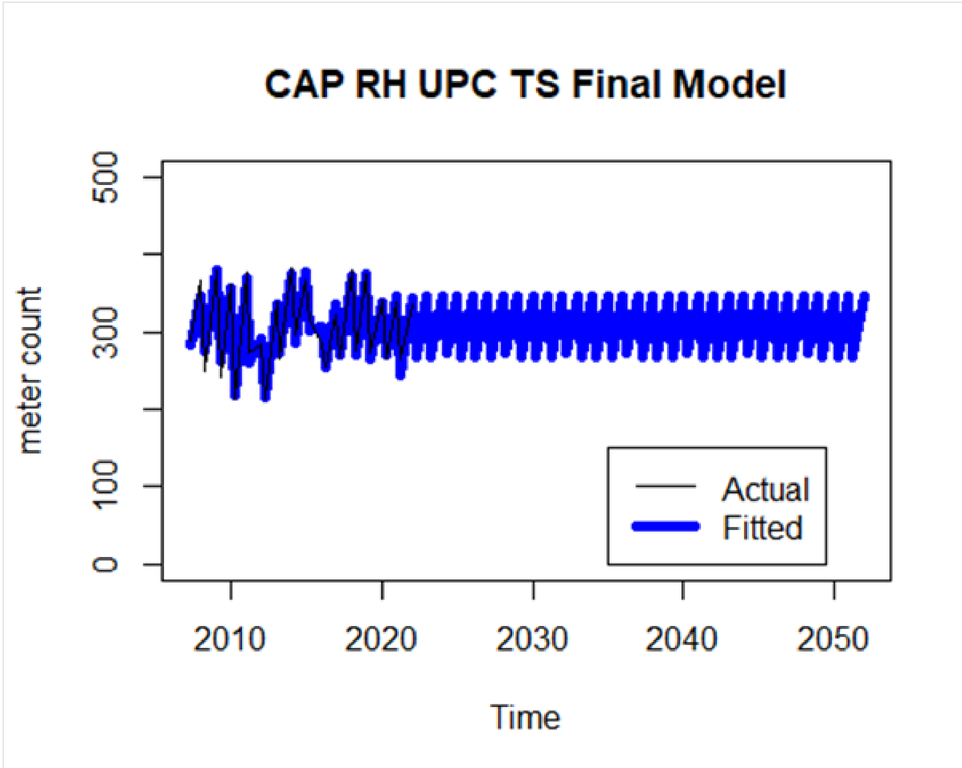
III.B.2.c.19 Colonial-Lowell Other Use per Customer Model

For its Lowell Other use-per-customer model of the peak period, the Company was unable to find a satisfactory model. It uses the most-recent observations for its forecast period.

III.B.2.c.20 Colonial-Cape Cod Residential Heating Use per Customer Model

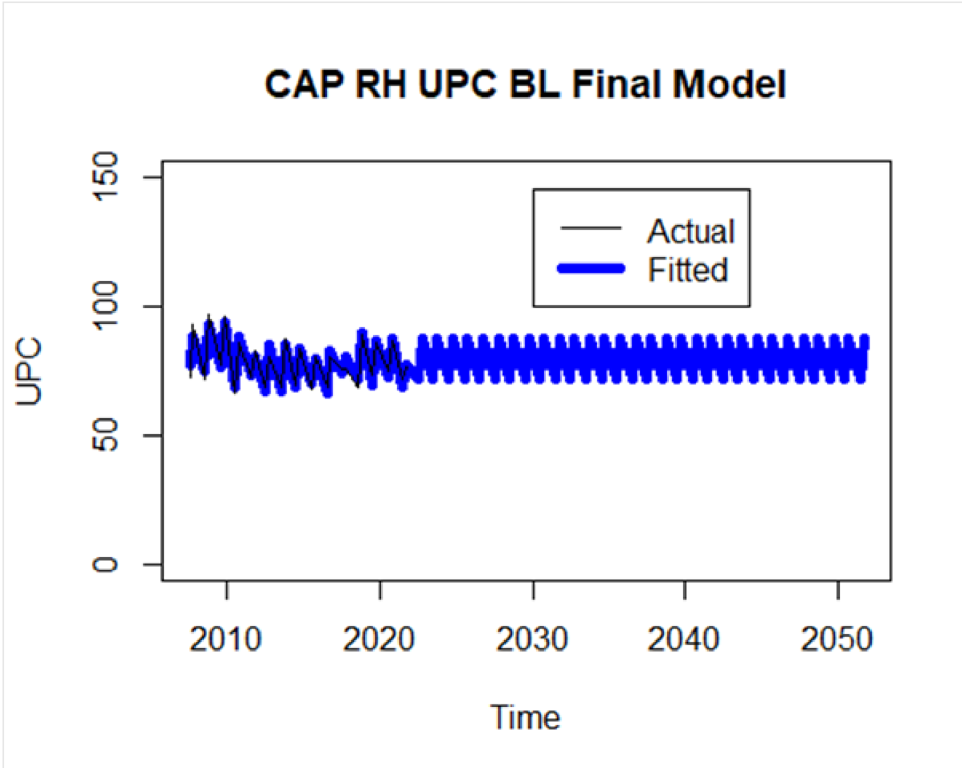
For its Cape Residential Heating use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD), the Q2 dummy variable, and one indicator variable to account for structural change in the data. The t-statistics for this model were all greater than 2.0 except for the intercept and the adjusted r-squared value was 0.99. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 10.3%.
- MAPE = 3.0%
- The ex-post predicted values < 9.2% error,
- All parameters in the ex-post change by less than 5.4%.



For its Cape Residential Heating use-per-customer model of the off-peak period, the Company developed a model using billing degree days (BDD), the Q4 indicator, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.90. The residuals of the model were heteroscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

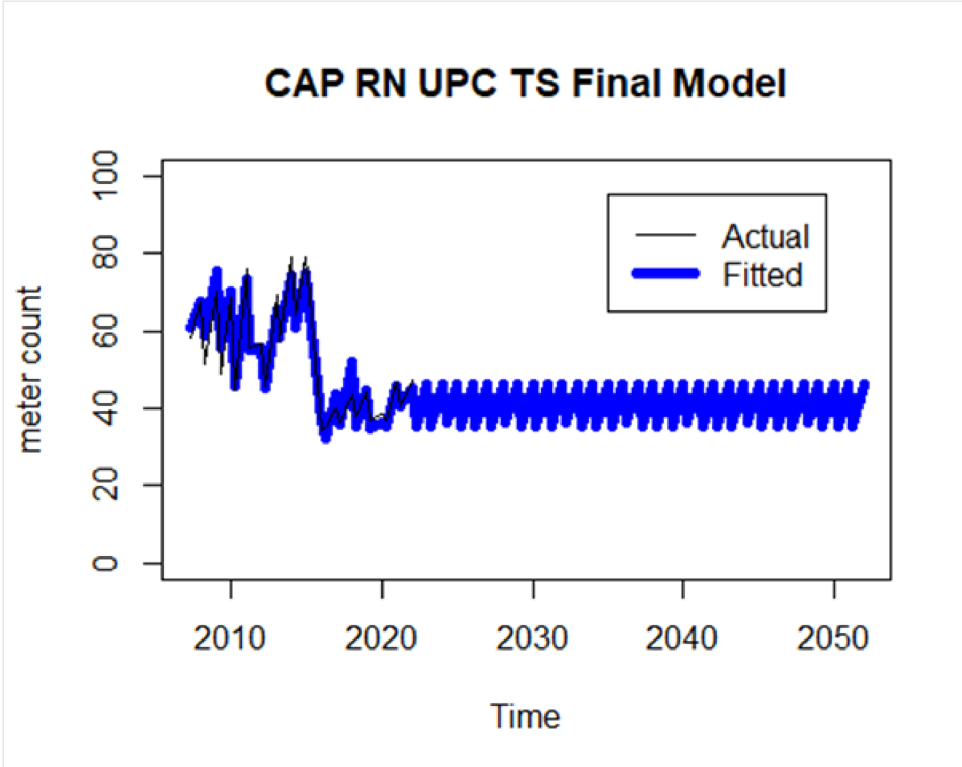
- All predicted/actual 'pct error' < 7.0%.
- MAPE = 2.79%
- All ex-post predicted values < 5.0% error,
- All parameters in the ex-post change by less than 4.8%.



III.B.2.c.21 Colonial-Cape Cod Residential Non-Heating Use per Customer Model

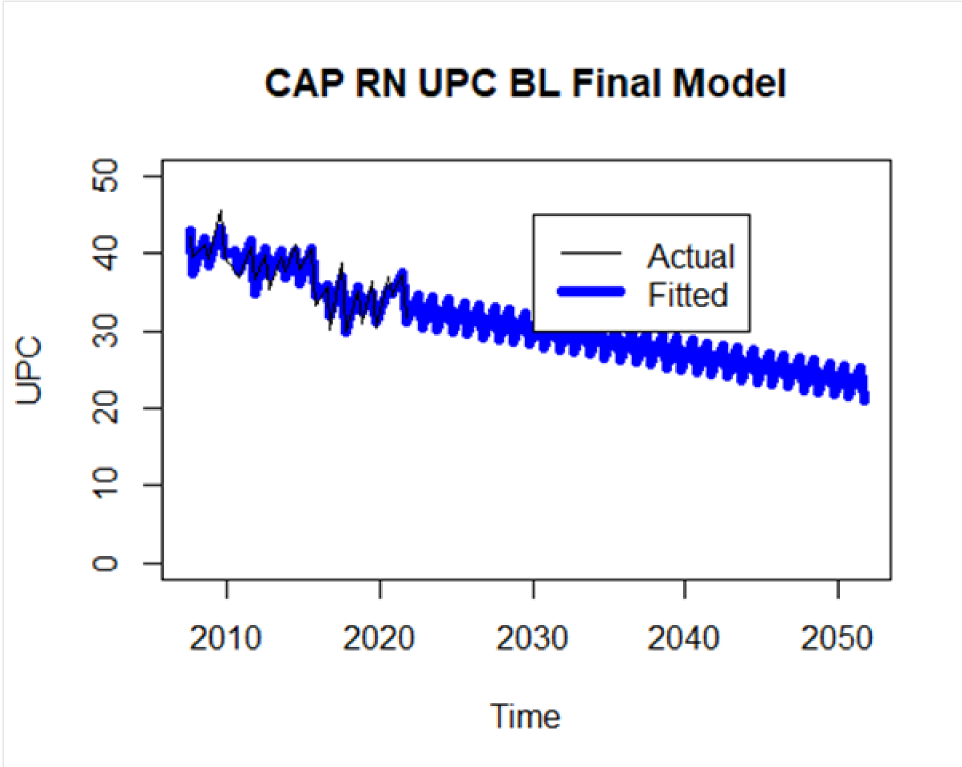
For its Cape Residential Non-Heating use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD), the Q2 indicator variable, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.93. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 14%, except for 2018.00 (-19.27%).
- MAPE = 5.18%
- One ex-post predicted value < 4% error, the other was 37 %
- All parameters in the ex-post change by less than 0.7%.



For its Cape Residential Non-Heating use-per-customer model of the off-peak period, the Company developed a model using time, billing degree days (BDD) and time, the Q4 dummy variable, and two dummy variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.86. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

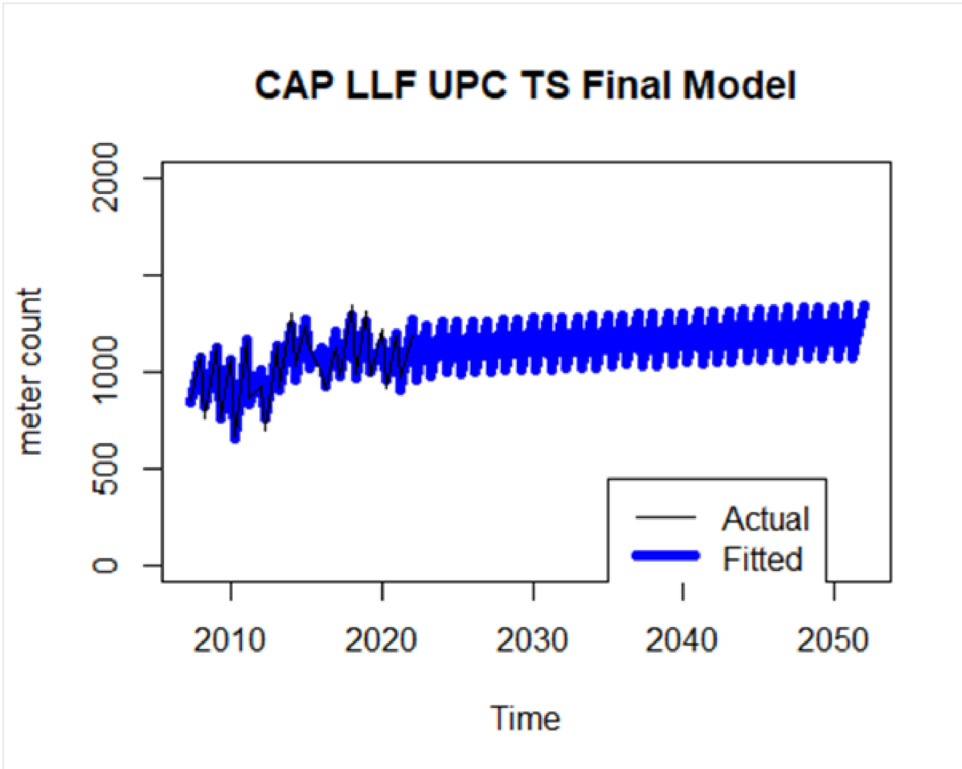
- All predicted/actual 'pct error' < 7.0%.
- MAPE = 2.86%
- All ex-post predicted values < 2.5% error,
- All parameters in the ex-post change by less than 4.9%.



III.B.2.c.22 Colonial-Cape Cod Commercial / Industrial Low Load Factor (LLF) Use per Customer Model

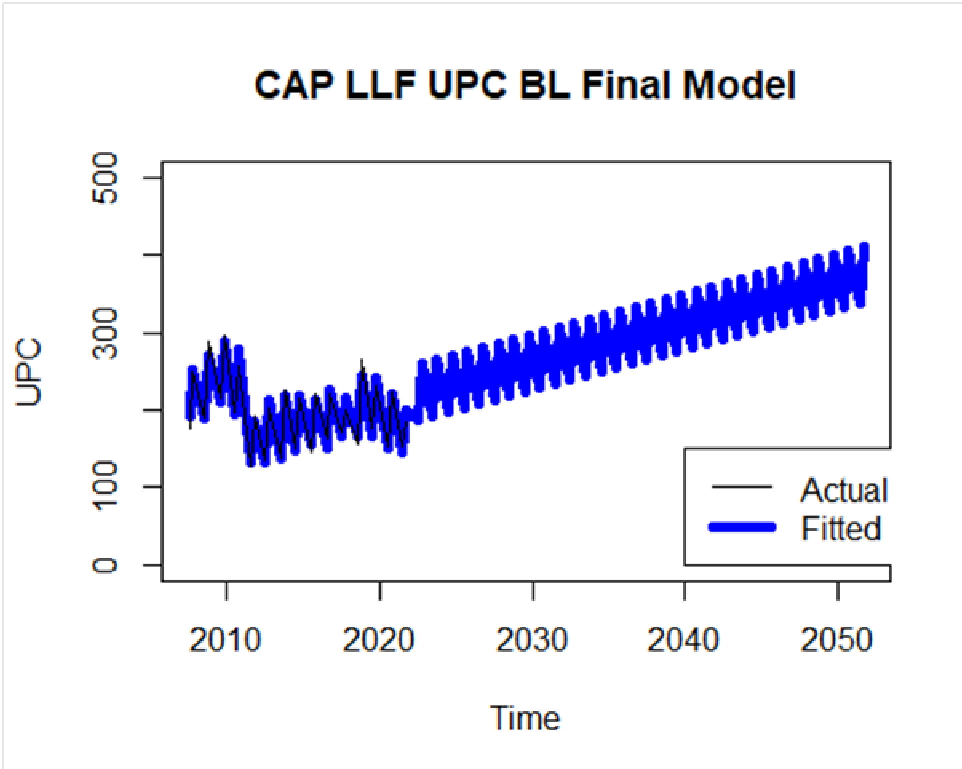
For its Cape Commercial / Industrial Low Load Factor use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD) and non-manufacturing employment, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.90. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 11.7%.
- MAPE = 3.94%
- All ex-post predicted values < 8.3% error,
- All parameters in the ex-post change by less than 9% except the intercept at 15.95%.



For its Cape Commercial / Industrial Low Load Factor use-per-customer model of the off-peak period, the Company developed a model using billing degree days (BDD) and time, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.94. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

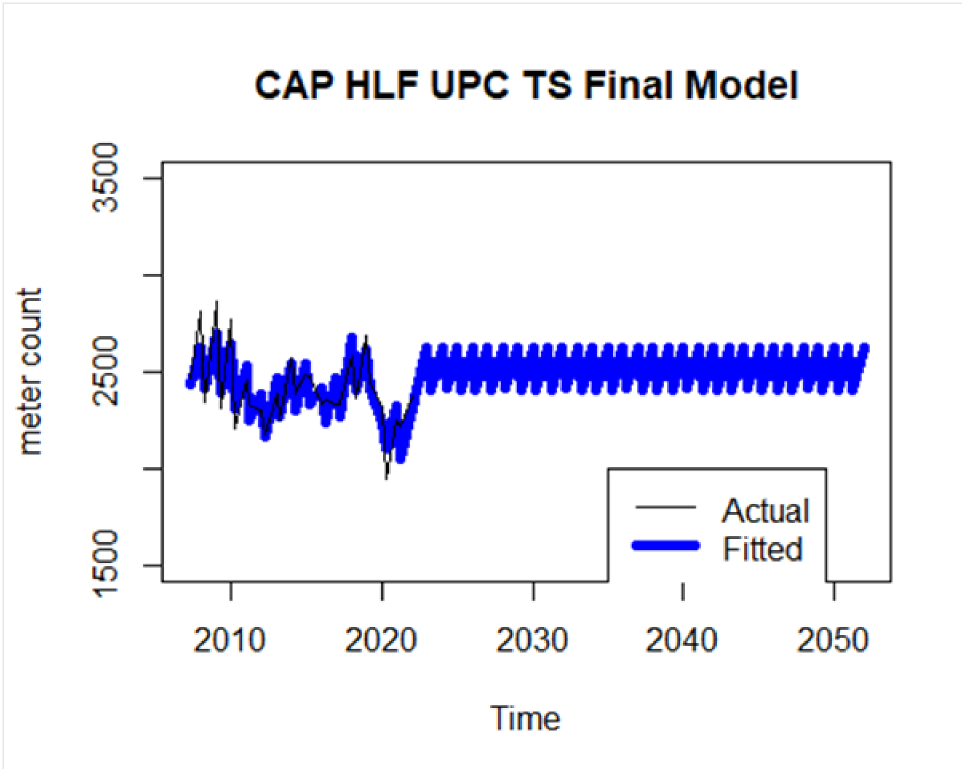
- All predicted/actual 'pct error' < 8.4%.
- MAPE = 4.11%
- One ex-post predicted value < 9.2% error
- All parameters in the ex-post change by less than 12.2%.



III.B.2.c.23 Colonial-Cape Cod Commercial / Industrial High Load Factor (HLF) Use per Customer Model

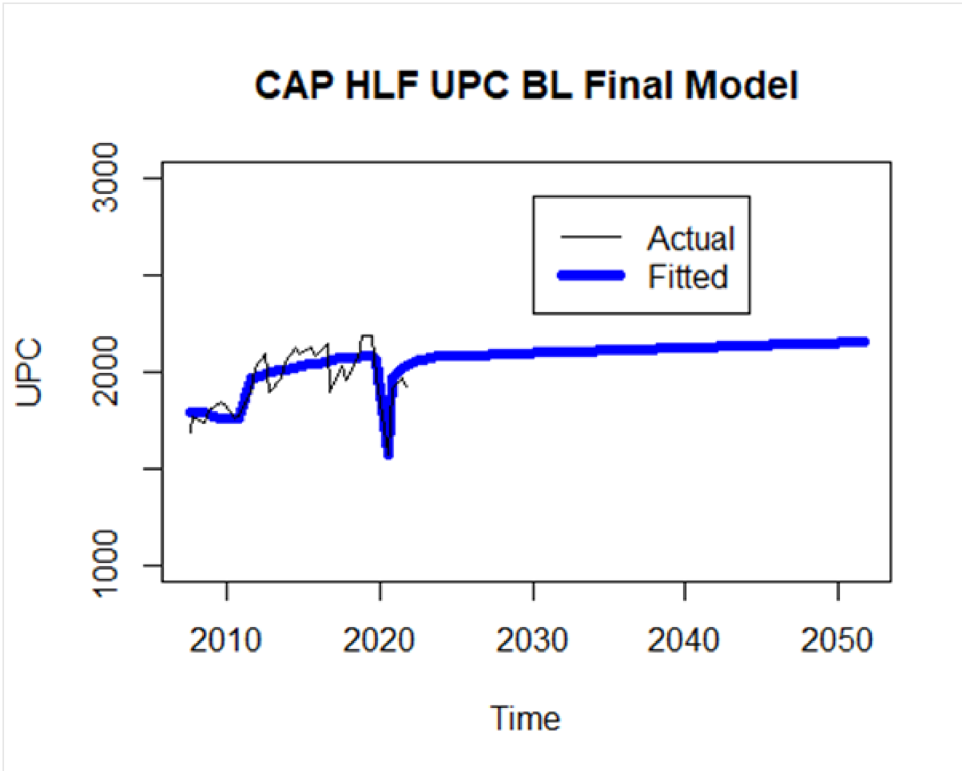
For its Cape Commercial / Industrial High Load Factor use-per-customer model of the peak period, the Company developed a model using billing degree days (BDD), and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0, except the intercept (1.95) and the adjusted r-squared value was 0.68. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 9.3%.
- MAPE = 3.78%
- All ex-post predicted values < 10% error,
- All parameters in the ex-post change by less than 12% except for one structural dummy (-17.7%).



For its Cape Commercial / Industrial High Load Factor use-per-customer model of the off-peak period, the Company developed a model using non-manufacturing employment, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0, except for the intercept, and the adjusted r-squared value was 0.73. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its. For this model:

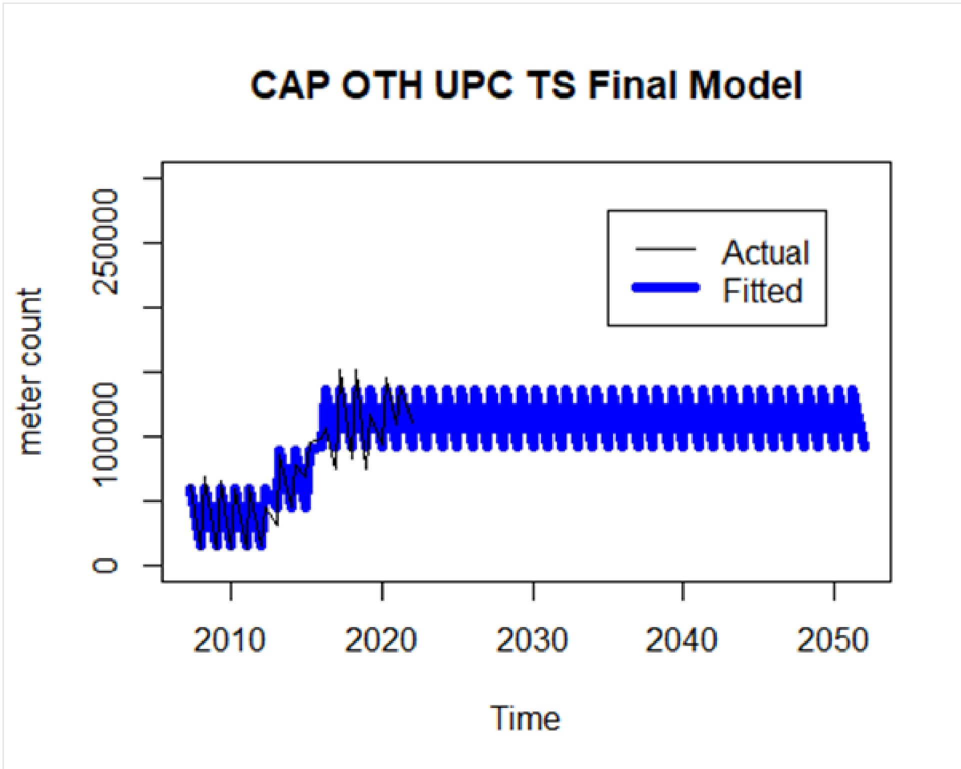
- All predicted/actual 'pct error' < 8.7%.
- MAPE = 3.27%
- All ex-post predicted values < 5.8% error,
- All parameters in the ex-post change by less than 4.3%.



III.B.2.c.23 Colonial-Cape Cod Other Use per Customer Model

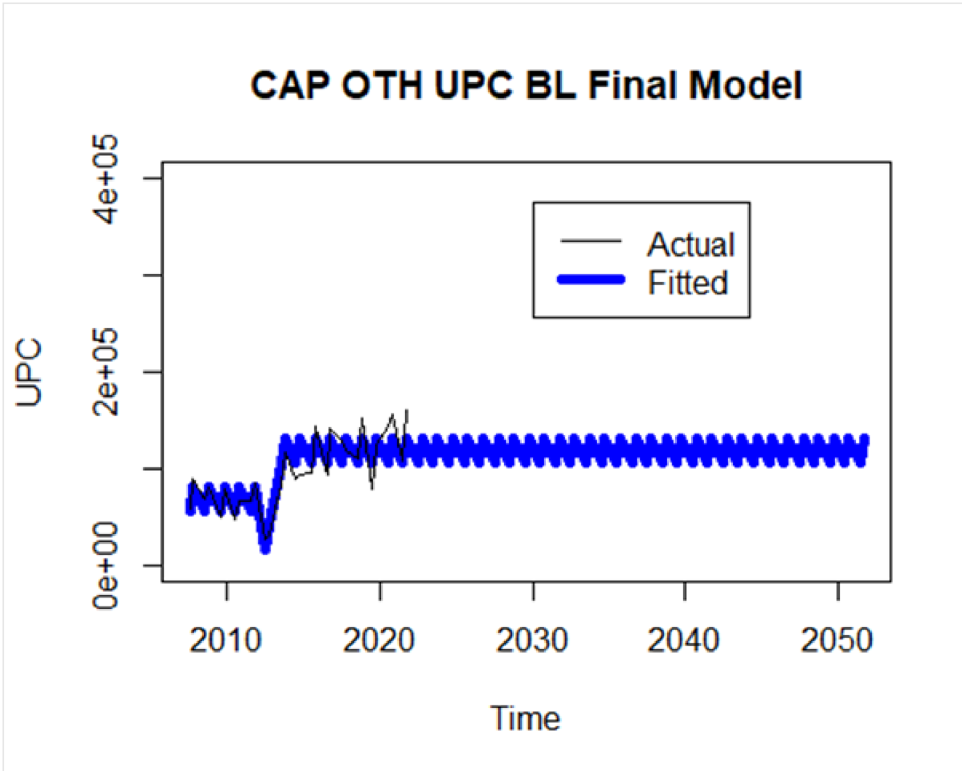
For its Cape Commercial / Industrial High Load Factor use-per-customer model of the peak period, the Company developed a model using the Q2 indicator variables, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.90. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- All predicted/actual 'pct error' < 15% in recent history; earlier history was more erratic.
- MAPE = 14.8%
- All ex-post predicted values < 23% error,
- All parameters in the ex-post change by less than 4.3%.



For its Cape Other use-per-customer model of the off-peak period, the Company developed a model using the Q4 indicator, and two indicator variables to account for structural changes in the data. The t-statistics for this model were all greater than 2.0 and the adjusted r-squared value was 0.76. The residuals of the model were homoscedastic, and the model passed the Chow test for stability. This model did not demonstrate AR(1) autocorrelation of its residuals. For this model:

- Most predicted/actual 'pct error' < 15%.
- MAPE = 15.4%
- One ex-post predicted value < 3% error and one was 25%,
- All parameters in the ex-post change by less than 7.9%.



III.B.2.e. Distribution of Quarterly Data into Monthly Data

While the Company's meter count and use per customer forecasts are performed on a quarterly level, for gas resource planning purposes, the Company first must convert the two forecasts from the quarterly level to the monthly level.

III.B.2.e.1. Meter Count

Once the Company's quarterly meter count forecast was completed, the Company performed a spline interpolation of the quarterly data to arrive at consistent monthly meter count values.

III.B.2.e.2. Volume

To create a monthly forecast of volumes, the Company first created a quarterly volume forecast by multiplying quarterly meter count by quarterly use per customer for each rate class, each company. The Company then allocated the quarterly values to the monthly level using historical distribution of volumes by quarter.

III.B.3 Non-Econometric Adjustments to the Retail Demand Forecast

III.B.3.a. Introduction

While the Company models rate groups that are aggregated to perform econometric forecasting, there were two adjustments which the Company had to consider in producing its final forecast: conversion of Capacity-Exempt customers to Capacity-Eligible service and the potential impact of the Company's energy efficiency programs.

III.B.3.b. Capacity-Exempt Market

In addition to its forecast of traditional (Sales and Customer Choice) markets, the Company also forecasts its capacity-exempt market, excluding certain large power generating facilities. While the Planning Team has historically had no planning obligation for the supply or capacity needs of its capacity-exempt customers, the Company's forecast includes them to enable it to tie together its retail (burner tip) and wholesale (citygate) forecasts for distribution-system and financial planning purposes. With the recent trend in capacity-exempt customers seeking to return to Sales or capacity-eligible service, accounting for this market in the Company's planning considerations at a high level continues to be important. A summary of this forecast is included as a line item in Chart III-A-1 (Base Case, High Case, and Low Case).

Through the end of the historical period of data for the Company's retail demand forecast (February 2022), the Company continues to see some of its capacity-exempt customers opt to return to capacity-eligible service, a trend that it expects to continue in the future. From the billing data of these returned capacity-exempt customers, the Company estimated daily normal-year and design-year customer requirements.

For gas resource planning purposes as discussed in Section IV, the Company modeled the conversion from capacity-exempt to capacity-eligible based on its most recent experience since this transition is not. The Company modeled this conversion with an incremental 241,971 Dth per year returning each year of the forecast (normal year basis).

For the design day, the capacity-exempt load added to the Sales and Customer Choice forecast was an incremental 1,914 Dth/day returning each year of the forecast.

III.B.3.c Energy Efficiency

National Grid operates natural gas energy efficiency programs for low income, residential, and commercial/industrial customer classes detailed in the plan for calendar years 2022-2024 in D.P.U. 21-124 (the "Three-Year Plan"). The Three-Year Plan was developed through collaboration with the Massachusetts Energy Efficiency Advisory Council, which includes key energy efficiency stakeholders such as the Department of Energy Resources, the Department of Environmental Protection, the Office of the Attorney General, environmental, housing, and manufacturing advocates, as well as residential and commercial customer stakeholders. Post-2024, the forecast assumes annual savings continue at a similar but declining rate.

Within the Company's retail modeling, its historical sales data includes the impact of actual energy efficiency savings from Company programs. Projected energy efficiency savings are included in the forecast as a reduction to the base econometric forecast when the annual savings exceeds the average of the most recent three years of actual savings. This prevents the double-counting of reductions due to energy efficiency.

The Company Energy Efficiency targets (Dths) in the Three-Year Plan, excluding savings from behavioral and fuel-switching programs, are shown in Table III.B.3.c. Since the 2022 to 2024 targets do not exceed the historical annual rate of energy efficiency, no explicit adjustments are made to the forecast as the projected savings are inherently built into the econometric models.

	Historical Annual EE Savings (Average of 2019 to 2021)	2022	2023	2024
Total	1,494,764	1,255,525	1,268,176	1,265,623

Over the last 10+ years, the Company has utilized an extensive stakeholder process to inform, propose, and ultimately deliver on the most ambitious natural gas energy efficiency programs in the country. The Company undertakes Potential Studies to inform each of its three-year planning cycles and it did so in 2021 with the help of Guidehouse to determine various scenarios of energy savings, the most relevant being a level of savings that is achievable within a reasonable and prudent budgetary limit.

In 2022-2024, the state set goals for the Program Administrators (PAs) that required National Grid to go above and beyond the "Business as Usual" (BAU) and approach their "BAU+" scenarios from their Potential Studies. In their most recent three-year plans, the PAs proposed unprecedented plans to address the state's greenhouse gas goals. These three-year plans were approved by the Department after detailed review, but the Department noted in their Order approving the PA's 2022-2024 Plans their concern with the cost of achieving the greenhouse gas goals set by the EEA.

Given concerns over bill impacts, the Department issued further guidelines to make sure that the additional spending which the PAs may request over the Plan term would be associated with incremental bill savings, pending Department review.

Given the substantial contribution from demand side resources already factored into the Company's load forecast and the likely outsized cost impact of pursuing incremental, localized efficiency and electrification, at this time there is little remaining opportunity to cost efficiently pursue additional efficiency through approaches that would not undermine the continued, healthy long-term development.

III.B.3.d. Electrification of Heat

The short-term outlook on heat pump installations is also based on the Company's 2022-2024 Three-Year Energy Efficiency Plan (D.P.U. 21-124). Post-2024, the forecast assumes annual heat pump installations continue at a similar, but increasing, rate. The forecast considers two kinds of heat pump installations, full and partial. Full heat pumps are sized to meet the customer's full heating requirements and the existing gas system is decommissioned when one is installed. The forecast treats each full heat pump installation as a meter loss, including all associated load.

Partial heat pumps are installed with integrated controls connected to the existing gas furnace, which remains in service. The Company assumed that the controls run the heat pump when outside temperatures are above 30 degrees F and switch to the gas system when temperatures are 30 degrees F or lower. Partial heat pumps are not treated as a meter loss in the forecast, but they are reclassified as partial heating customers and their gas usage is reduced by the amount normally used when temperatures are above 30 degrees. Design day load is unaffected.

Chart III.B.3.d shows the total projected heat pump installations broken out by type and rate group for the Company's Massachusetts service territories. The majority of installations are expected to be partial heat pumps in the short-term, which will not have an impact on design day as the back-up natural gas systems are assumed to operate at colder temperature. Most installations are forecasted to impact residential customers.

Cumulative Heat Pump Installations by Type for Massachusetts				
	Residential		Commercial	
Year (CY)	Full Heat Pump	Partial Heat Pump	Full Heat Pump	Partial Heat Pump
2022	260	384	16	45
2023	568	989	41	113
2024	984	1,939	74	204
2025	1,439	3,079	109	302
2026	1,939	4,413	148	410
2027	2,487	5,941	190	527

III.B.3.e. BERDO

The Boston Building Emissions Reduction and Disclosure Ordinance (BERDO), passed in October 2021, sets declining GHG emissions limits for large buildings in the City of Boston beginning in 2025. The emission limits are aimed at gradually reducing large building emissions to Net Zero by 2050. Emissions can be cut through energy efficiency, fuel switching, decarbonization of fuels, or any combination of the three.

Nearly all building types were already at or below the 2025-2029 emission limits in 2019, on average. The exceptions were Lodging and Multifamily Housing. Both were close but slightly above the 2025-2029 BERDO limits. However, all building types must reduce emissions by 2030 for compliance. Building owners can reduce emissions in a variety of ways, as shown below. Some of these actions lower gas use, some are neutral to gas use, and some raise gas use:

- Energy efficiency/weatherization (lowers gas use)
- Oil-to-gas conversions (increases gas use)
- Steam-to-gas conversions (increases gas use)
- Oil-to-electric conversions (neutral to gas use)

- Steam-to-electric conversions (neutral to gas use)
- Gas-to-full electric (lowers gas use)
- Gas-to-partial electric (lower gas use)
- Decarbonize energy supplies, install renewables on-site (neutral to gas use)
- Pay penalty (neutral to gas use)

Thus, there are multiple pathways to achieving the BERDO emissions limits, based on different combinations of the above measures, including high electrification pathways and hybrid pathways consistent with the Company's Clean Energy Vision.

The Company developed a BERDO building gas use forecast that assumes a continuation of savings from the Company's existing and planned energy efficiency programs, including electrification; conversion from oil-to-gas heating in all buildings by 2024; hybrid electrification from 2024 to 2050; and gradual ramp-up of renewable natural gas and green hydrogen to 100% of supply by 2050. These measures are sufficient to keep all building types in the Company's Boston territory in compliance with BERDO, on average, through 2050.

A large portion of these gas usage reductions are covered by the energy efficiency and electrification projections already included in the GLF. Therefore, net reductions were used to avoid double counting of forecasted reductions in gas usage Table III.B.3.e shows the net reductions required from large buildings to be in compliance with BERDO until 2027.

Net Adjustment for BERDO in Boston				
Year (CY)	Residential	Commercial	Industrial	Total
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	25,596	18,079	2,599	46,275

III.B.3.f. Gas Demand Response

National Grid, along with its New York affiliate, has been developing and implementing Gas Demand Response ("Gas DR") programs designed to deliver peak day and/or peak hour savings dating back to 2016. Specific to Massachusetts, National Grid contributed to a Gas DR study delivered to the Department of Energy Resources (DOER) in 2019 and later proposed a set of Gas DR demonstrations in its 2020 Rate Case (D.P.U. 20-120).

In D.P.U. 20-120, National Grid was ordered to retract its request and instead file for any Gas DR demonstrations or programs in the Company's Statewide Energy Efficiency Plan ("EE Plan"). The Company explored two pathways for Gas Demand Response under the EE Plan - a full-scale statewide program and a demonstration.

In assessing the potential for a statewide program, the Company screened various program designs for cost-effectiveness using the Avoided Energy Supply Cost (AESC) values established prior to each three-year EE Plan cycle (Synapse, March 2021). The AESC Study's closest approximation for Peak Day gas costs utilizes a "Costing Period" in which costs are averaged over the 10 highest use days of the winter. This results in an avoided cost value of $33/Dth-D. As a result, no Gas DR program design was shown to be cost-effective relative to the Peak Day AESC values established for the 2022-24 plan.

In the other pathway, a Gas DR demonstration program would only need to show a path to cost-effectiveness and not be duplicative of any existing demonstration programs in the state. Demonstration programs would be limited in size and scope, minimizing the potential load reduction impact they could have in the short term. An active Gas DR demonstration by Eversource and low AESC avoided cost values led to the decision not to include a Gas DR demonstration in the EE Plan.

Evidence suggests that the gas costing periods established in the AESC study, while suitable for traditional energy efficiency measures, may not be granular enough to differentiate the Peak Day value that could be avoided by a Gas DR program. This is supported by the Company's recent experience soliciting new gas supply options, which provide the most realistic benchmark of the cost of new peak day gas supply.

Following the release of the 2021 AESC Study, National Grid and the other PAs engaged Synapse to develop a Supplemental Study of peak gas benefits with a focus on determining an avoided cost value for an additional Costing Period. The additional Costing Period looked at avoided costs associated with the Design Day, resulting in an avoided cost value approximately $300/Dth-per-day. The Design Day avoided cost values in the Supplemental Study (Synapse, June 2021) showed that a Load Shedding DR program consisting of large Commercial and Industrial customers that switch to an alternate fossil fuel or reduce non-heating loads for a considerable time with no snapback would be cost-effective. However, the Departments Order on the 2022-24 Energy Efficiency Plan (D.P.U. 21-128, dated 1/31/22) established that the Supplemental AESC values cannot be used at this time as they were developed outside of the traditional AESC Report process. The table below shows the approximate Benefit-Cost Ratio (BCR) scores of three Gas DR program types under both the official AESC Study and the Supplemental Study.

Program	AESC Study (Avoided Cost of $33/Dth-per-Day)	AESC Supplemental Study (Avoided Cost of $300/Dth-per-Day)
C&I Load Shedding	0.13	1.22
C&I Load Shifting	0.03	0.31
Residential Thermostats	0.02	0.15

As shown in the table above, additional program types (C&I Load Shifting program and Residential Thermostats) showed improved BCRs under the Supplemental AESC values but were still not cost effective. National Grid believes those programs are better suited for peak hour constraints. In the EE Plan, the Company committed to a continued exploration of localized distribution constraints that could be mitigated through these peak hour focused programs.

National Grid will continue to evaluate the potential for Gas DR programs to support regional supply and local distribution needs while adhering to established Department energy efficiency guidelines required for program or demonstration approval through established mid-term modification (MTM) guidelines.

III.B.4 Sensitivity Analysis

III.B.4.a. Overview

To test the sensitivity of its retail demand forecast to economic changes, the Company also produced a High Case and Low Case forecast using two alternative economic scenarios from its economic forecast vendor, Moody's, from April 2020. For its High Case, the Company chose the Moody's high case that is designed so that there is a 4% probability that the economy will perform better than this scenario. For its Low Case, the Company chose the Moody's low case that is designed so that there is a 4% probability that the economy will perform worse than this scenario.

The Company's normal-year annual customer requirements for traditional markets (Sales and Customer Choice) under its three economic scenarios are from Chart III-A-1 (Base Case; High Case; and Low Case) are shown in Figure 1 below.

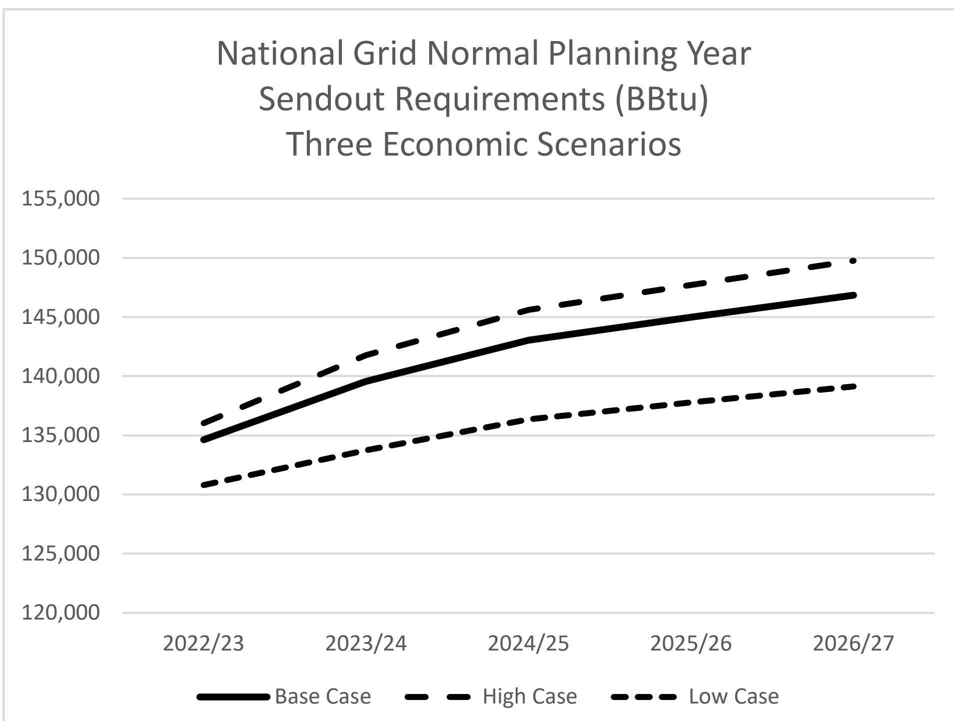


Figure 1

III.B.4.b. Development of Demand Scenarios

III.B.4.b.1. Introduction

Chart III-A-1 (High Case) and Chart III-A-1 (Low Case) summarize the Company's three forecasted customer requirements for the two sensitivity scenarios. The effect of the High Case economic scenario shows higher customer requirements than the Base Case forecast. The effect of the Low Case economic scenario shows lower customer requirements than the Base Case forecast.

III.B.4.b.2. High-Demand Scenario

To generate the High Case demand forecast, the Company substituted Moody's high economic scenario values of the data series used as independent variables into its econometric equations. It then re-ran the regression equations it had developed for each model to produce its high-demand forecast scenario.

A summary of the High Case forecast is found in Chart III-A-1 (High Case) and in Tables G-1 through G-5 (High Case). The High Case forecast results in average incremental growth in customer requirements that are 3,365 BBtu per year, 388 BBtu per year higher than the base case, with an average annual growth rate of 2.1% compared to the Base Case growth rate of 1.8%.

III.B.4.b.3. Low-Demand Scenario

To generate the Low Case demand forecast, the Company substituted Moody's low scenario values of the data series used as independent variables into its econometric equations. It then re-ran the regression equations it had developed for each model to produce its low-demand forecast scenario.

A summary of the Low Case forecast is found in Chart III-A-1 (Low Case) and in Tables G-1 through G-5 (Low Case). The Low Case forecast results in average incremental growth in customer requirements that are 1,991 BBtu per year, 986 BBtu per year lower than the base case, with an average annual growth rate of 1.3% compared to the Base Case growth rate of 1.8%.

III.B.5. Comparison of the D.P.U. 20-132 and the 2022 Demand Forecasts

Chart III-B-4 compares National Grid's current Base Case normal year forecast with the Base Case forecast presented in previous filing (D.P.U. 20-132) on an average annual basis.

Chart III-B-4 shows that the Company's forecast of 140,663 BBtu for 2024/25 in its D.P.U. 20-132 forecast for the traditional market was 4.2% higher than the 2024/25 value of 135,040 BBtu in the instant filing. The Company's forecast at the time of the D.P.U. 20-132 filing reflected a higher growth rate of 1.9% per annum in the traditional market coming out of the COVID-19 pandemic. The average annual load additions in the traditional market in the current forecast of 2,913 BBtu is higher than the 2,523 BBtu value in the previous forecast, reflecting the recovery post-COVID-19.

III.B.6. Comparison of Forecast and Actual Load

Chart III-B-5 shows the results of the Company's backcast analysis of predicted demand by the residential and the commercial/industrial rate classes versus the actual demand. Chart III-B-5 presents the annual accuracy for the six split years of March through February for the years 2016/17 through 2021/22. Chart III-B-5 shows the year-to-year accuracy in its meter count forecast, its use-per-customer forecast, and its resulting volume forecast. Averaging the annual predicted and actual volumes over the six-year period, the Company's volume forecasting shows an overall accuracy within 0.68% over the time period.

III.C Translation of Demand Forecast into Customer Requirements

III.C.1 Introduction

In the second step of National Grid forecasting methodology, the Company translates its monthly demand forecast into monthly customer requirements, unaffected by billing cycle lag. This translation requires the Company to account for the difference between gas arriving at its city gates ("supply forecast") and gas metered at its customers' burner tips ("demand forecast"). This translation requires adding an amount of supply which represents unaccounted-for gas and then accounting for the billing lag.

III.C.2 Unaccounted-For Gas

The difference between gas supply metered at the Company's city gates and that which is metered at its customers' burner tips is Unaccounted-For Gas. The Company calculated a percentage for each division by which the billed sales (plus Company Use) needed to be grossed up based on the difference over the period Sep 2020 - Aug 2021. Figure 1 below shows the Unaccounted For percentage by division resulting from this analysis.

Calculated Unaccounted-For Percentage by Division

Division	**Unaccounted For (%)**
Boston	***3.1 %***
Essex	***2.6 %***
Lowell	***-2.6 %***
Cape Cod	***2.1 %***

Figure 2

III.C.3 Unbilled Sales

With the addition of Company Use and Unaccounted-For Gas to the Company's demand forecast, the Company had volumes that were equivalent, except for accounting for billing lag. To align the demand forecast with the supply forecast, the Company developed a logical model of the lag in billing its customers based on its underlying historical and future meter reading schedule. The Company used this model to then determine the lag-induced difference between its gas deliveries as metered at the citygate and its gas deliveries as metered at its customers' burner tips.

The Company calculated the unbilled volumes by division by taking the difference between the historical actual monthly sendout figures and the historical actual billed sales figures (including Company Use and Unaccounted For). It then calculated a linear regression model by division of the unbilled volumes versus the difference between actual monthly heating degree days and the monthly billing degree days as determined using the billing cycle model described above over the period September 2019 – August 2021. Since unbilled volumes are a function of timing of delivery versus meter reading, the resulting regression equations were specified with a zero intercept, with the theory being that the differences between sendout and sales tend to zero over time, with only minor differences caused by the year-to-year adaptation of the Company's billing schedule to the actual calendar.

Using the future normal billing degree days from its billing cycle model and its normal calendar heating degree days, the Company then calculated the normalized unbilled volumes by division which it then added to its normal forecasted billing volumes for the forecast period to determine its forecast of normal monthly volumes to be delivered to its city gates by division.

III.D Regression Equation

In the third step of National Grid's forecasting methodology, the Company uses regression equations of daily sendout versus daily temperature for the most recent twelve months to allocate its monthly normal forecasted customer requirements to daily normal customer requirements by division. This step is used to determine National Grid's normal year forecast of customer requirements over the forecast period and to determine National Grid's design year forecast of customer requirements over the forecast period for resource planning purposes. To perform its regression analysis, the Company used version 4.1.2 of the R statistical software package[5].

The Company developed a linear-regression equation using data for the reference-year period April 1, 2021 through March 31, 2022. Its regression equation uses total firm sendout (excluding powerplants) as its dependent variable and temperature as its independent variable[6].

Through the use of the linear-regression equation, the Company is able to normalize daily sendout. Specifically, the actual daily firm sendout is regressed against effective degree day

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5 "R is a language and environment for statistical computing and graphics. It is free, open source, and well documented. It is widely used for forecasting and statistical analysis.

6 Sendout includes both Sales and supplier service ("Customer Choice") customer requirements, as well as those of its capacity-exempt customers.

("EDD") data as provided by its weather service vendor WSI, EDD 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 National Grid daily sendout requirements.

National Grid uses the Boston/Logan International Airport weather station (KBOS) as the source of the weather data that is used as the principal explanatory variable in its regression equations. The Boston 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 EDD value for each 24-hour 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. Throughout its regression analysis, the Company used the WSI EDD data when the daily value was greater than zero. When EDD equaled zero, the Company defined that day's EDD as 65° F minus the daily average air temperature so as to have a continuous range of temperature data and avoid the left-truncation that occurs in the standard definition of degree days.

Based on its observations of the relationship between sendout and EDD over the split years 2007/08 through 2021/22, 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 spaceheating usage and spaceheating 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 daily sendout and EDD. This form of regression equation is the same that the Company used in its 2020 Long Range Resources and Requirements filing (D.P.U. 20-132).

In the tables below, Intercept is the Dth sendout predicted at EDD=0, Slope1 is the Dth/EDD usage below the Breakpoint EDD level, Slope2 is the incremental Dth/EDD usage above the Breakpoint EDD level, the Standard Error is expressed in Dth, and the Breakpoint EDD is the EDD 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 EDD increases in value, then sendout will increase, which agrees with what the Company observes.

From the frequency plots (periodogram) of the residuals of the sendout vs. EDD regression, the Company continues to observe a significant peak at frequency 0.14 (and its harmonic at 0.28), which indicates a correlation in the error term once in 1/0.14, or 7, days, confirming the Company's observations that weekday and weekend sendout requirements are different at similar EDD levels in its Boston, Essex, and Lowell divisions. Examining the average of the residuals by division and by day of the week, the Company again used 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 introduction of this second independent variable adds an incremental improvement in the adjusted R^2 of the equations and, more importantly, eliminates the 7-day correlation of the residuals. The sign of the coefficient (negative) implies that there is a reduction in sendout on weekend days versus weekday days at similar temperatures, as has been observed by the Company.

Again, the Company observed a correlation between lagged temperature and the residuals of the above equation and it investigated adding a third independent variable. Its three choices were: (1) the difference between EDD on day t and EDD on day t-1, (2) the difference between EDD on day t and mean of the EDD on day t-1 and day t-2, or (3) the difference between EDD on day t and the mean of the EDD on day t-1 and day t-2 and day t-3. The differences were used in lieu of the actual lagged values to avoid correlation among the independent variables. The Company chose option (2) as the optimal additional independent variable. 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 negative sign of the coefficient 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 tables below list the coefficients for the final regression equation form for the Company's Boston, Essex, Lowell and Cape Cod divisions. As noted above, in the instant filing, the Company uses its 2021/22 regression equations to allocate its monthly forecasted volumes to its daily forecasted volumes.

Boston

Segmented Regression Results for Boston sendout vs. EDD and Weekend and Lagged Delta EDD

Split Year	Intercept	Slope1	Slope2	Weekend	Lagged Delta EDD	Standard Error	Adjusted R^2	Breakpoint EDD
2007/08	129,938	2,491	10,421	-8,712	-2,363	19,000	0.9877	9.45
2008/09	126,751	2,418	10,579	-8,939	-2,522	18,990	0.9896	9.49
2009/10	121,385	2,561	10,406	-7,651	-2,483	16,930	0.9901	9.27
2010/11	122,868	2,220	10,842	-7,427	-1,797	17,120	0.9918	9.12
2011/12	126,114	2,388	10,509	-8,694	-1,651	18,000	0.9856	8.55
2012/13	120,974	1,919	11,461	-8,869	-1,572	17,500	0.9906	8.61
2013/14	123,435	1,869	11,969	-8,104	-1,492	21,880	0.9898	8.53
2014/15	127,417	2,534	11,608	-11,276	-1,910	24,640	0.9887	8.32
2015/16	140,000	2,225	11,786	-10,330	-1,762	23,450	0.9826	8.56
2016/17	140,942	2,138	12,352	-9,068	-2,622	19,850	0.9896	8.43
2017/18	144,568	2,609	12,412	-7,668	-2,653	22,080	0.9899	9.13
2018/19	145,749	2,462	12,672	-7,123	-2,812	22,620	0.9883	7.86
2019/20	152,613	2,790	12,142	-9,047	-2,847	28,100	0.9759	7.46
2020/21	135,452	2,517	12,445	-5,413	-2,444	23,320	0.9858	9.58
2021/22	148,970	2,814	11,757[7]	-9,373	-2,532	20,160	0.9899	8.52

Figure 3

[7] Due to the significant decline in the Slope2 variable in the BOS 2021/22 regression equation that the Company attributes to the effect of the COVID-19 Omicron variant, the Company inserted the value of 12,115 which is the average of the 2019/20, 2020/21, and 2021/22 Slope2 values as more reflective of its expectations as a springboard to the 2022/23 Planning Year.

Essex

Segmented Regression Results for Essex sendout vs. EDD and Weekend and Lagged Delta EDD

Split Year	**Intercept**	**Slope1**	**Slope2**	**Weekend**	**Lagged Delta EDD**	**Standard Error**	**Adjusted R^2**	**Breakpoint EDD**
2007/08	6,957	183	816	-657	-172	1,725	0.9830	9.56
2008/09	6,702	157	837	-613	-186	1,763	0.9844	9.67
2009/10	6,580	155	828	-589	-163	1,547	0.9853	9.44
2010/11	6,965	136	857	-597	-126	1,560	0.9880	9.17
2011/12	6,980	151	844	-827	-114	1,569	0.9813	8.53
2012/13	6,919	149	889	-795	-114	1,673	0.9848	10.09
2013/14	6,736	122	935	-715	-99	1,949	0.9860	8.76
2014/15	7,063	162	865	-778	-117	1,909	0.9871	8.44
2015/16	7,193	158	877	-813	-128	1,852	0.9803	8.42
2016/17	7,123	130	943	-641	-185	1,889	0.9826	8.42
2017/18	7,561	172	914	-522	-183	2,047	0.9836	8.87
2018/19	7,646	192	957	-506	-209	2,037	0.9833	8.45
2019/20	7,871	193	947	-793	-218	2,370	0.9703	7.50
2020/21	7,206	183	927	-529	-174	2,138	0.9786	9.45
2021/22	8,486	194	915[8]	-773	-186	1,873	0.9850	8.40

Figure 4

[8] Due to the significant decline in the Slope2 variable in the ESX 2021/22 regression equation that the Company attributes to the effect of the COVID-19 Omicron variant, the Company inserted the value of 930 which is the average of the 2019/20, 2020/21, and 2021/22 Slope2 values as more reflective of its expectations as a springboard to the 2022/23 Planning Year.

Lowell

Segmented Regression Results for Lowell sendout vs. EDD and Weekend and Lagged Delta EDD

Split Year	**Intercept**	**Slope1**	**Slope2**	**Weekend**	**Lagged Delta EDD**	**Standard Error**	**Adjusted R^2**	**Breakpoint EDD**
2007/08	17,216	304	1,626	-1,746	-363	3,863	0.9780	8.48
2008/09	17,701	284	1,564	-1,680	-364	3,825	0.9792	9.21
2009/10	17,230	170	1,721	-1,753	-355	3,470	0.9803	8.34
2010/11	18,530	219	1,674	-2,050	-273	3,277	0.9852	9.14
2011/12	18,473	291	1,613	-2,327	-266	3,957	0.9670	8.95
2012/13	16,832	193	1,698	-2,187	-236	3,467	0.9815	8.26
2013/14	17,330	217	1,753	-1,987	-226	4,039	0.9824	8.99
2014/15	16,996	284	1,731	-2,603	-275	4,082	0.9835	10.11
2015/16	16,709	241	1,694	-2,311	-271	4,245	0.9703	8.17
2016/17	16,294	223	1,788	-1,957	-379	4,010	0.9776	8.31
2017/18	16,579	308	1,741	-1,582	-359	4,311	0.9791	9.39
2018/19	17,206	348	1,786	-1,680	-422	4,553	0.9761	8.17
2019/20	17,542	442	1,658	-1,961	-432	4,838	0.9650	7.42
2020/21	16,259	269	1,647	-1,390	-323	3,706	0.9789	8.54
2021/22	17,254	388	1,683	-2,073	-388	4,199	0.9786	8.37

Figure 5

Cape Cod

Segmented Regression Results for Cape Cod sendout vs. EDD and Weekend and Lagged Delta EDD

Split Year	**Intercept**	**Slope1**	**Slope2**	**Weekend**	**Lagged Delta EDD**	**Standard Error**	**Adjusted R^2**	**Breakpoint EDD**
2007/08	13,635	268	1,234	0	-251	3,274	0.9718	10.51
2008/09	13,493	273	1,212	0	-286	3,181	0.9770	10.45
2009/10	13,749	274	1,340	0	-294	3,202	0.9740	11.90
2010/11	13,598	206	1,339	0	-181	2,883	0.9819	10.47
2011/12	13,456	176	1,244	0	-142	3,142	0.9633	8.59
2012/13	13,015	161	1,433	0	-184	3,397	0.9723	10.49
2013/14	13,380	145	1,431	0	-127	3,524	0.9788	9.17
2014/15	13,770	200	1,411	0	-160	4,114	0.9736	10.45
2015/16	14,297	282	1,333	0	-182	3,859	0.9615	10.52
2016/17	13,752	205	1,408	0	-295	3,395	0.9750	8.73
2017/18	14,704	340	1,422	0	-322	3,997	0.9739	11.70
2018/19	14,192	235	1,541	0	-333	3,574	0.9776	8.66
2019/20	15,198	351	1,346	0	-322	4,037	0.9605	8.60
2020/21	14,484	312	1,439	0	-274	3,813	0.9718	10.42
2021/22	15,403	327	1,341	0	-297	3,723	0.9740	8.80

Figure 6

The figures above set forth the 2021/22 regression coefficients for the four National Grid divisions. The functional form of the equation, in pseudocode, is then:

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

As seen above, the adjusted R-squared values for all 2021/22 regressions are all in the range of 0.97 to 0.99, 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, with the exception of the weekend variable in the Cape Cod division. Since the weekend variable again showed weak statistical significance for the Cape Cod model, the Company omitted that variable from its regression equations.

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

III.E Normalized Forecast of Customer Requirements

III.E.1 Normal Year

To establish the normal year's daily EDD data, the Company calculated the average annual number of EDD for the Logan International Airport ("LIA") weather station for the twenty-year period (calendar years 2002 through 2021), with an average of 6,112 EDD and a standard deviation of 420.26 EDD.

The Company then prepared a "Typical Meteorological Year" by selecting, for each calendar month, the month in the LIA weather database that most closely approximated the twenty-year average EDD and standard deviation for each month. A summary of the monthly averages for the LIA weather site is listed in Figure 6 below.

Average Monthly EDD and Average of Monthly Standard Deviations for the Logan International Airport Weather Station

Month	**EDD**	**Standard Deviation**
Jan	1,199	10.6
Feb	1,031	8.8
Mar	919	9.2
Apr	553	8.0
May	270	6.5
Jun	64	3.4
Jul	2	0.5
Aug	1	0.4
Sep	65	3.1
Oct	342	7.0
Nov	668	8.5
Dec	998	9.0
Total	6,112	

Figure 7

In the third step of the Company's forecasting methodology set forth in Section III.A above, the Company allocates each of the monthly demand forecast volumes discussed in the section above (using normal year EDD) based on the ratio of the daily to monthly totals from the Company's normalized 2021/22 regression equation, to yield the forecast of capacity-eligible customer requirements under normal weather conditions for the Base Case, High Case, and Low Case economic scenarios[9].

[9] Normal year customer requirements are prior to exogenous addition of capacity-exempt load assumed to return to capacity-eligible service. Normal year customer requirements do not reflect leap years.

Base Case

Base Case Normal Year Customer Requirements (BBtu)

	2022/23	2023/24	2024/25	2025/26	2026/27
Heating Season	92,101,612	95,666,660	98,513,829	99,809,633	101,068,375
Non-Heating Season	42,534,869	43,900,934	44,533,048	45,168,666	45,787,422
Total	134,636,480	139,567,594	143,046,877	144,978,299	146,855,797
Per-Annum Growth		4,931,114	3,479,283	1,931,422	1,877,498
Per-Annum Growth %		3.7%	2.5%	1.4%	1.3%

Figure 8

High Case

High Case Normal Year Customer Requirements (BBtu)

	2022/23	2023/24	2024/25	2025/26	2026/27
Heating Season	92,851,523	97,061,335	100,229,804	101,638,782	103,006,655
Non-Heating Season	43,181,844	44,703,153	45,389,140	46,074,962	46,743,162
Total	136,033,367	141,764,488	145,618,944	147,713,744	149,749,817
Per-Annum Growth		5,731,121	3,854,456	2,094,800	2,036,074
Per-Annum Growth %		4.2%	2.7%	1.4%	1.4%

Figure 9

Low Case

Low Case Normal Year Customer Requirements (BBtu)

	2022/23	2023/24	2024/25	2025/26	2026/27
Heating Season	89,997,014	91,908,259	94,037,669	95,022,288	95,910,263
Non-Heating Season	40,792,180	41,819,012	42,304,188	42,759,081	43,209,379
Total	130,789,193	133,727,271	136,341,857	137,781,369	139,119,642
Per-Annum Growth		2,938,078	2,614,586	1,439,512	1,338,273
Per-Annum Growth %		2.2%	2.0%	1.1%	1.0%

Figure 10

III.F 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.

In the Department’s decision in D.P.U. 16-40 (Eversource Long-Range Plan), the Department stated that it will no longer require companies to file a cost-benefit analysis for its planning standards with its future supply plans. In D.P.U. 20-132, the Company maintained the frequency of occurrence of its design year of 1:34.40 years established in its D.P.U. 16-181 Long Range Resource and Requirements Plan that produced a design year of 7,098 EDD. The Company also confirmed that maintaining its existing design day of 78 EDD was appropriate with a frequency of occurrence of 1:47.9 years.

III.F.1 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 Figure 12 below.

Design Year and Design Day Criteria

Element	**Value**
Design Year EDD	7,060
Frequency of Occurrence	1 / 34.4 years
Design Day EDD	78
Frequency of Occurrence	1 / 47.9 years

Figure 11

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

III.F.1.a Design Day Standard

The purpose of a design day standard is to establish the amount of system-wide throughput (interstate pipeline and underground-storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system. In this filing, the Company defines its design day standard at 78 EDD with a probability of occurrence of once in 47.9 years, as a result of its on-going review of planning standards.

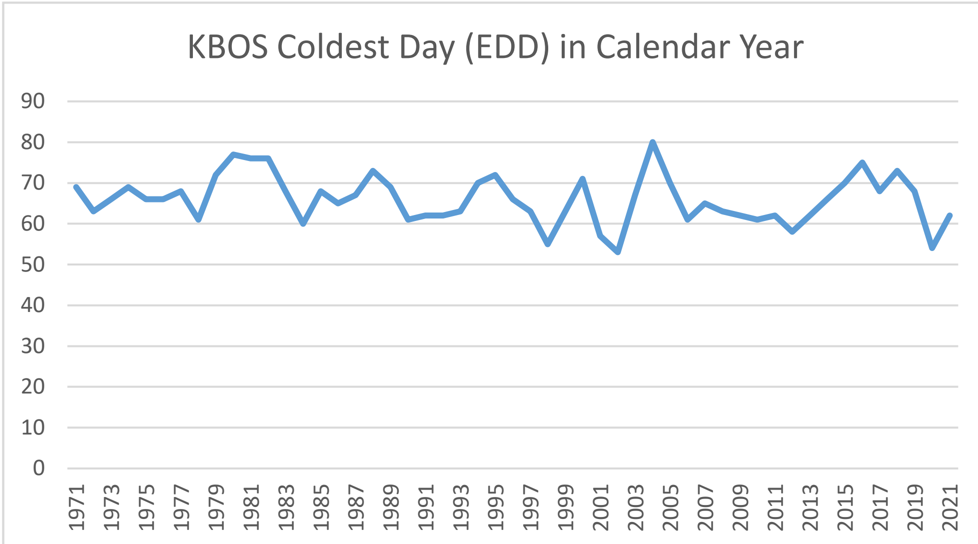

Figure 12

To confirm its design day selection, the Company reviewed the coldest day that occurred in each calendar year from 1971 to 2021 (51 years). The mean was 65.96 EDD with a standard deviation of 5.91 EDD. Maintaining the design day frequency of occurrence of 1:35.31 years used by the Company in D.P.U. 20-132 would lead to a design day of 76.8 EDD under the updated normal distribution.

III.F.1.b Design Year Standard

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. In this filing, the Company defines its design year standard as 7,060 EDD with the same probability of occurrence of once in 34.42 years as used in its D.P.U. 20-132 Long-Range Plan.

In performing its review of the Company's design standards for the instant filing, the Company reviewed its annual effective degree day (EDD) data in its database which now contains data through calendar year 2021. While there will be variations in annual EDD, there is a distinct downward trend in its annual EDD for the Boston/Logan (KBOS) weather station of approximately 13 EDD per year reflective of the impact of climate change in Eastern Massachusetts (Figure 10). Therefore, the Company is updating the statistics of its design year.

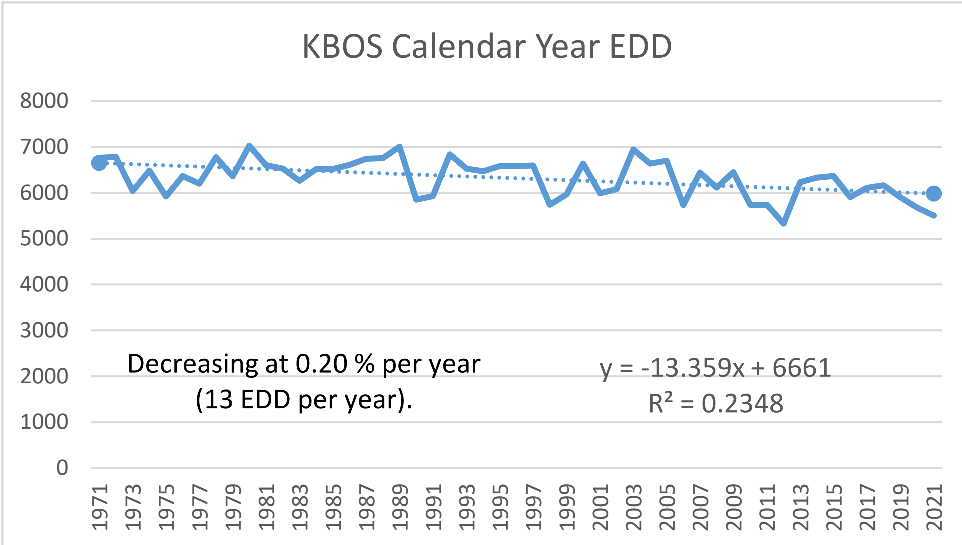

Figure 13

To confirm its design year selection, the Company reviewed the total annual EDD that occurred in each calendar year from 1982 to 2021 (40 years). The mean was 6,267.5 EDD with a standard deviation of 418.3 EDD. Using this normal distribution, the 1:34.4 year probability of occurrence translates into a design year of 7,060 EDD.

III.G 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 applied its normal year daily EDD pattern and its design year daily EDD pattern to its 2021/22 regressions equations, which are derived from the sendout regression analysis, to yield two springboard year estimates of normal year and design year daily customer requirements. The five-year daily forecast of normal year customer requirements generated by the Company's demand forecast was then scaled by the 2021/22 ratio of each day's design year to normal year daily requirements ratio to produce an equivalent five-year daily forecast of design year customer requirements. Below are tables for the resulting design year requirements of the Company’s capacity-eligible customers for the base case, high case, and low case demand forecasts.

Base Case

Base Case Design Year Customer Requirements (BBtu)

	2022/23	2023/24	2024/25	2025/26	2026/27
Heating Season	105,433,444	109,510,655	112,766,640	114,248,698	115,688,366
Non-Heating Season	45,660,046	47,125,430	47,799,828	48,478,874	49,139,460
Total	151,093,489	156,636,085	160,566,469	162,727,572	164,827,826
Per-Annum Growth		5,542,595	3,930,384	2,161,103	2,100,254
Per-Annum Growth %		3.7%	2.5%	1.3%	1.3%

Figure 14

High Case

High Case Design Year Customer Requirements (BBtu)

	2022/23	2023/24	2024/25	2025/26	2026/27
Heating Season	106,290,295	111,104,711	114,728,100	116,339,546	117,903,949
Non-Heating Season	46,352,378	47,984,019	48,716,180	49,448,987	50,162,620
Total	152,642,674	159,088,729	163,444,280	165,788,533	168,066,569
Per-Annum Growth		6,446,056	4,355,550	2,344,253	2,278,036
Per-Annum Growth %		4.2%	2.7%	1.4%	1.4%

Figure 15

Low Case

Low Case Design Year Customer Requirements (BBtu)

	2022/23	2023/24	2024/25	2025/26	2026/27
Heating Season	103,024,970	105,210,721	107,646,372	108,773,130	109,789,178
Non-Heating Season	43,794,149	44,896,935	45,414,112	45,899,680	46,379,802
Total	146,819,119	150,107,656	153,060,483	154,672,809	156,168,980
Per-Annum Growth		3,288,538	2,952,827	1,612,326	1,496,171
Per-Annum Growth %		2.2%	2.0%	1.1%	1.0%

Figure 16

III.H Hourly Planning

The Company maintains a Design Hour (the peak hour on a Design Day) planning criteria for planning purposes to determine the level of supply and pressure needed to deliver gas without interruption when demand is highest – typically during the early morning hours (when customers generally turn up the thermostat and use gas for hot water/cooking), on days that meet the Design Day criteria. The Design Hour criteria is five percent of the Design Day.

The Design Hour criteria determines the level of deliverability capacity to and from city gate stations as well as on-system supply resources during the hour of the day when maximum gas is consumed as customers turn up their thermostats, cook, and use gas for hot water heating. If customers used the same volume of gas each hour, it would suffice to look at the daily demand and divide by twenty-four to ensure the system could provide that amount of gas each hour. The reality is that customers tend to use more gas in the early morning hours, typically 6 a.m. to 10 a.m., and again in the evening from 4 p.m. to 8 p.m.

The Company uses the Design Hour criteria to perform various analyses necessary for distribution system operations (e.g., regulator pressure settings, LNG requirements) and capital planning. Moreover, the Company has used the Design Hour criteria for certain short-term gas supply planning decisions.[10]

To date, the Company has not used the Design Hour requirement as the basis for entering into long-term gas contracts but must be mindful of its contractual rights when making planning decisions, particularly in a constrained upstream market. For example, under the Company's contracts with Algonquin, those calculated hourly flow limits are either 1/24th or 6% of the daily MDQ under each contract. The total calculated hourly flow limits for each take station are then equal to the combined calculated hourly flow limit for all contracts providing deliveries to each take station. Historically, Algonquin has not imposed any requirements that its customers manage hourly takes to fall within the calculated hourly flow limits, nor has Algonquin restricted the Company's ability to balance its overall takes across all take stations, but the Company must be prepared for the possibility that Algonquin will do so. Accordingly, the Company may seek to incorporate design hour requirements into future portfolio planning decisions so that it is able to comply with future orders from the pipelines.[11]

The Company is including information in its forecast and supply plan regarding Hourly Planning because the Company foresees the possibility of needing to procure longer-term supply resources to meet Design Hour needs. Absent the addition of new infrastructure into the region, incremental supplies available to the Company are limited to imported LNG by a limited number of suppliers. As the upstream pipelines serving the Company's distribution system continue to become more constrained, the operational flexibilities which they have historically provided will continue to diminish. Moreover, as New England competes with the international market for the limited supply of imported LNG, available resources to serve demand, including hourly demand, will become further constrained.

The five percent Design Hour criteria is supported by observed data. Over the last twelve years, the average peak hour sendout of the top twelve coldest days[12] is 5.0% of daily sendout. In addition, the average peak hour sendout for all days below 15 degrees Fahrenheit (when non-firm customers are generally interrupted) is 5.0%. The average peak hour sendout for the coldest day of each year over the last twelve years is 5.0% of daily sendout.

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[10] The Company maintains sufficient resource to meet the forecasted peak hour needs in the Cape Cod portion of its distribution system.

[11] For the 2022/23 winter, the Company has installed portable LNG on Cape Cod in order to meet forecasted peak hour customer requirements.

[12] Only non-holiday weekdays are considered (gas days Monday through Thursday) for all calculations in this paragraph. "Coldest" days are the days with the lowest average daily temperature of the gas day.

Design Day conditions have not been experienced over the last twelve years, but a recent Company analysis has determined that the 5% Design Hour criteria continues to be appropriate under design conditions. A summary of the analysis is below.

The Company developed a logarithmic regression model for the peak hourly sendout each day using the following independent variables:

Total daily sendout (for a gas day which is defined as the 24 hours starting at 10 a.m. ET each day),

Delta temperature: The difference between the average daily temperature and the temperature at the time of the peak hourly sendout for that day,

An indicator variable for interruptions: i.e. a variable that is set to one when the average daily temperature is below 15 degrees, which is when non-firm customers are typically asked to stop burning gas, and

Several indicator variables to account for calendar effects, including weekends, Monday mornings, and annual indicators.

Only data from December through March of each year were included in the model since design conditions only occur in the winter in Massachusetts. All parameters are statistically significant at the 5% level (or better[13]) and the adjusted R-squared value is 95.6% indicating the model is a good fit. Low variance inflation factors indicate the model is not impacted by multi-collinearity.

To estimate Design Hour conditions, the Company evaluated the regression model with Design Day sendout from 2022[14] and the 90th percentile for the delta temperature (i.e. the difference between the average daily temperature and the temperature during the peak hour), which yields a Design Hour sendout that is 5.0% of the Design Day sendout. This confirms that the average peak hour sendout over the coldest days that the Company observed of 5% also holds under Design Conditions.

IV. Design of the Resource Portfolio

IV.A Portfolio Design

In the third step of the Company's resource-planning process, the Company evaluates the existing resource portfolio in relation to the firm sendout forecast developed in Section III above. 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

[13] One indicator variable is significant at the 5% level, all remaining parameters are significant at the 1% level or better.

[14] See section III.F.

requirements over the longer term.

Since 1996, the Company has been using the SENDOUT® model developed by New Energy Associates, now ABB, 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 SENDOUT® model can be used in one of two ways. First, the model can be used to determine the best use of a given portfolio of supply, capacity and storage contracts to meet a specified demand. That is, it can solve for the dispatch of resources that minimizes the cost of serving the specified demand given the existing resource and system-operating constraints. The model dispatches resources based on the lowest variable cost to meet demand, assuming that demand charges are fixed. Second, the SENDOUT® model can be used to determine the optimal portfolio to meet a given demand. To do this, the model uses a linear programming algorithm to analyze the combination of contracts and the size of each contract (i.e., MDQ) to determine the combination that results in the lowest total cost, taking into account both variable and fixed costs.

For purposes of this filing, the SENDOUT® model optimizes the portfolio for normal and design weather with various growth scenarios and cold snap scenario. The results provide the least-cost dispatch solution over the five-year planning horizon for a given weather pattern. The Company utilizes the output produced by the model to identify the mix of resources required. The results provide the basis for the Company's five-year gas supply portfolio plan, including any modifications required to meet projected demand.

IV.B Analytical Process and Assumptions

For the purpose of preparing this Supply Plan filing, the Company analyzed three demand scenarios, i.e., the low-demand scenario, the base-case scenario and the high-demand scenario, 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 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 Sales and Customer Choice customers. Second, the Company assumed that, throughout the forecast period, firm transportation customers who historically have not been served by the Company's gas supply portfolio and are not subject to the assignment of capacity ("Capacity Exempt") continue to opt for sales service and therefore become part of the Company's planning load[15]. Third, the Company assumed that all transportation and underground storage contracts expiring during the forecast period would be renewed with no change in pricing, quantities or operating characteristics.

IV.C Expected Available Resources

This section describes National Grid's current resource portfolio and discusses the modifications that National Grid 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 National Grid resource portfolio is composed of the following categories of available resources: (1) transportation contracts; (2) underground storage contracts; (3) peaking resources; and (4) gas commodity contracts. Table G-24(A) provides a list of each of the Company's existing upstream transportation and underground storage contracts, in addition to each of the Company's supply contracts.

IV.C.1 Transportation Contracts

National Grid has capacity entitlements on multiple upstream pipelines that allow for the delivery of gas to its citygates in Massachusetts. 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 least-cost and reliable delivery of gas supplies. In general, the National Grid transportation agreements provide: (a) transportation to the Company's citygates for Gulf Coast, Mid-Continent, Northeast Market Area and Canadian supplies; (b) transportation for underground storage withdrawal and injection; or (c) the flexibility to meet balancing and no-notice requirements.

National Grid'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, Mid-Continent and the Northeast to underground storage facilities in Maryland, New York, Pennsylvania and West Virginia and to the Company's Massachusetts citygates. Second, the Company has contract entitlements to short-haul capacity that is used to transport gas from underground storage fields to National Grid's Massachusetts citygates. These short-haul capacity entitlements are also used to ensure the deliverability of non-storage supplies to the Company's citygates, 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 National Grid's Massachusetts citygates. The transportation contracts

[15] Since the winter of 2013/14, the Company has seen a number of its capacity-exempt customers opt to return to capacity-eligible service, a trend that it expects to continue into the future. In fact, heading into the 2022/23 winter, an increased number of customers have expressed interest in returning to capacity-eligible service. In Section III of this filing the Company has described in further detail the capacity exempt customers and the methodology used to determine a certain level of capacity exempt customers that are forecasted to return to sales service. The Company's forecasted amount is consistent with the reverse migration forecast approved by the Department in docket D.P.U. 15-129, at 16-17. See D.P.U. 16-52, Order at 44.

allow for varying degrees of flexibility with respect to such features as no-notice requirements and nomination time changes. For example, the Company maintains no-notice contracts on Algonquin. These no-notice contracts allow for nominations to be made throughout the day up until the last hour of the gas day, allowing the Company the ability to balance system load.

National Grid's upstream pipeline capacity contracts are regulated by the Federal Energy Regulatory Commission ("FERC"). FERC regulates the rates and services for natural gas pipeline transportation and storage facilities, as well as certification of new facilities and abandonment of existing facilities, primarily under the Natural Gas Act. FERC's authority under the Natural Gas Act ensures that the rates, terms and conditions of service by parties subject to its jurisdiction are just and reasonable and not unduly discriminatory or preferential.

National Grid's transportation contracts regulated by the FERC are described below:

> Algonquin Gas Transmission Company: National Grid maintains total firm capacity entitlements of 573,245 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 upstream of the Algonquin system that provide access to upstream production and storage areas.

> Eastern Gas Transmission and Storage, Inc. (formerly Dominion Energy Transmission Inc.): National Grid maintains total firm capacity entitlements of 12,978 MMBtus/day on the Eastern Gas Transmission and Storage ("Eastern Gas") pipeline system. The capacity path transports gas received from interconnects at Lebanon, Pennsylvania or Dominion South Point and delivers into Texas Eastern at Leidy, Pennsylvania.

> Enbridge Gas Inc. (formerly Union Gas): National Grid maintains total firm capacity entitlements of 74,160 MMBtus/day on the Enbridge Gas Inc. ("Enbridge") pipeline system. The capacity path originates at Dawn, Ontario and delivers into TransCanada at Parkway, Ontario.

> Iroquois Gas Transmission System: National Grid maintains total firm capacity entitlements of 52,203 MMBtus/day on the Iroquois Gas Transmission ("Iroquois") pipeline system. Supplies are transported via the Iroquois system from the Canadian/New York border at Waddington, New York to the Tennessee interconnect at Wright, New York.

> Millennium Pipeline Company, LLC: National Grid maintains total firm capacity entitlements of 50,000 MMBtu/day on Millennium pipeline system. The capacity path originates at Corning, New York and delivers into the interconnection with Algonquin at

Ramapo, New York.

Portland Natural Gas Transmission System (“PNGTS”): National Grid maintains total firm capacity entitlements of 57,068 MMBtu/day on PNGTS. The capacity path originates at E. Hereford, Quebec and delivers into the interconnection with TGP at Dracut, MA.

Tennessee Gas Pipeline: National Grid maintains total firm capacity entitlements of 409,073 MMBtus/day on the Tennessee Gas Pipeline (“TGP”) to its Massachusetts citygates. National Grid also holds an additional 38,528 MMBtu/day of long-haul capacity that delivers into the TGP interconnect with Algonquin in Mendon, Massachusetts to the Company’s Algonquin citygates. In the production area, the TGP system splits into three legs: the 100 leg, the 800 leg and the 500 leg. These legs transport gas from five areas: South Texas, Eastern Texas, Western Louisiana, Mississippi and Eastern Louisiana. In addition, the TGP system is divided into seven market zones, from Zone 0 in South Texas to Zone 6 in New England.

Texas Eastern Transmission Company: National Grid maintains total firm contract entitlements of 265,933 MMBtus/day of capacity directly connected to supply and storage areas on the Texas Eastern Transmission Company (“Texas Eastern”) system. The Texas Eastern system 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 National Grid 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. Each of the Company’s transportation contracts with Texas Eastern deliver into the interconnection with Algonquin at Lambertville, New Jersey or Hanover, New Jersey located in M3.

TransCanada Pipeline: National Grid maintains total firm capacity entitlements of 73,973 MMBtus/day on the TransCanada Pipeline (“TransCanada”) system on two paths. The first capacity path for 16,793 MMBtus/day originates at the interconnection with Union Gas at Parkway, Ontario and delivers into Iroquois at Waddington, New York. The second capacity path for 57,180 MMBtus/day originates at Parkway, Ontario and delivers into PNGTS at East Hereford, Quebec.

Transcontinental Gas Pipeline Corporation: National Grid maintains total firm capacity entitlements of 6,911 MMBtus/day on the Transcontinental Gas Pipeline Corporation

("Transco") pipeline system. The capacity path originates at Wharton, Pennsylvania and delivers into Algonquin at Centerville, New Jersey.

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. By using long-haul capacity to fill underground storage, the Company is able to use those resources at a higher load factor. Lastly, underground storage greatly enhances the flexibility of portfolio, allowing the Company to manage major fluctuations in weather from day to day, as well as within the day. Like the transportation contracts described in Section IV.C.1, these underground storage services are also regulated by the FERC. A summary of the Company's underground storage services are provided in the table below:

Pipeline Company	**Rate Schedule**	**Maximum Daily Withdrawal Quantity ("MDWQ")**	**Maximum Storage Quantity ("MSQ")**	**Maximum Daily Injection Quantity ("MDIQ")**
Eastern Gas Transmission and Storage, Inc.	GSS-TE Storage	53,457	5,521,661	30,676
Eastern Gas Transmission and Storage, Inc.	GSS Storage	2,326	232,600	1,292
Honeoye	SS-NY Storage	6,150	981,120	4,672
Tennessee	FS-MA Storage	95,415	7,603,290	50,689
Texas Eastern	SS-1 Storage	75,740	5,431,577	27,919
TOTAL		**233,088**	**19,770,248**	**115,248**

IV.C.3 Peaking Resources

In addition to interstate pipeline and underground storage resources, National Grid utilizes peaking supplies to meet its design day and design season requirements. Peaking supplies are a critical component of the resource mix in that these supplies provide National Grid 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 peaking resources to meet system needs.

IV.C.3.a. Off-System LNG Facilities

Off-system peaking resources include the Company's storage contract with National Grid LNG, LP ("NGLNG").

Contract	Description	Term	MDQ (MMBtu)	ACQ (MMBtu)
National Grid LNG, LP	Firm Storage Service	November 1, 2022 - October 31, 2023 (evergreen)	35,000	1,159,664

The NGLNG facility is located in Providence, Rhode Island. To date, the Company has refilled its storage capacity at the NGLNG facility with trucked LNG throughout the off-peak period, with the target to be full as of December 1st of each year. Upon the in-service date of NGLNG's liquefaction facilities discussed in Section IV.C.5.b, the Company will no longer depend upon trucking activity to meet its refill requirements at NGLNG. During the winter period, this gas is vaporized and delivered via Algonquin to the Company's citygates in Massachusetts.

IV.C.3.b On-System LNG Facilities

On-system peaking resources are the local production plants that store LNG until vaporized. These LNG storage facilities are targeted to be full as of December 1st of each year. National Grid's on-system LNG 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-1 shows the locations of these facilities. Because these resources can be brought on line quickly, these plants can be used to meet hourly fluctuations in demand, maintain deliveries to customers and balance pressures across portions of the distribution system during periods of high demand. Most importantly, these resources are vital in preserving delivery pressures in the event that an off-system resource becomes unavailable. In addition, since several of the Company's on-system LNG facilities are located in areas that are fed by a single interconnection with the interstate pipeline system, these facilities provide the only supplemental supply and/or back up source for that area. The Company's on-system LNG resources are listed in the table below:

Location	Facility Type	Maximum Daily Withdrawal Quantity (MDWQ) (MMBtu)	Maximum Storage Quantity (MSQ) (MMBtu)
Commercial Point (Dorchester)	LNG	198,968	1,192,345
Lynn	LNG	120,142	1,045,000
Salem	LNG	31,768	1,045,000
Tewksbury[16]	LNG	83,600	1,045,000
S. Yarmouth	LNG	27,600	179,740
Wareham	LNG	4,494	9,234
Haverhill	LNG	41,069	418,000
Total		**507,641**	**4,934,319**

These on-system LNG facilities are also refilled via truck deliveries, mainly during the off-peak period from various locations. The table below provides a listing of the Company's current LNG liquid supply agreements in place for both the current off-peak period and peak period for the time period beginning November 1, 2022.

Contract	Description	Term	MDQ (MMBtu)	ACQ (MMBtu)
Gaz Metro LNG	Firm Liquid Service (summer refill)	April 1, 2022 – November 30, 2022	8,000	1,117,000
UGI	Firm Liquid Service (summer refill)	April 1, 2022– November 30, 2022	9,000	1,150,000

16 Tewksbury vaporization capability is scheduled to increase from 83,600 MMBtu/day to 104,500 MMBtu/day for winter 2026/27.

Contract	Description	Term	MDQ (MMBtu)	ACQ (MMBtu)
Constellation LNG	Firm Liquid Service (winter refill)	December 1, 2022 – March 31, 2023	7,600	273,600

In addition, the Company contracts 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 as well as portable equipment where On-System LNG Facilities are insufficient to meet requirements. The Company is currently arranging for its 2022/2023 trucking needs.

IV.C.3.c. New England Market Area Supplies

Where the Company's existing resource portfolio is insufficient to meet the Company's forecasted design-year sendout requirements for a given forecast period, the Company must consider incremental resources over and above the available assets in the Company's portfolio. Historically, the Company has been able to satisfy this deficit via city-gate delivered supplies, but opportunities to do so are currently limited by a number of factors, including but not limited to; existing market conditions, capacity availability, primary point deliverability and supply availability.

Limitations of market conditions, availability and deliverability are reflective of the lack of infrastructure available in the region able to satisfy the demand for natural gas by both local distribution companies and power generation. Today, New England Market Area Supplies able to satisfy the Company's need are primarily limited to imported LNG that can either be (i) vaporized directly into the Company's distribution system by a third party or (ii) delivered via additional transportation capacity contracts on Tennessee, Algonquin and Maritimes and Northeast Pipeline. Absent any further gas infrastructure expansions or upgrades, reliance on this additional pipeline capacity is limited in availability and can only be used to transport supplies from east end LNG receipt terminals including Beverly and Dracut as well as the Distrigas of Massachusetts terminal owned and operated by Constellation LNG, LLC to limited delivery points on the Company's distribution system. Further, any unsubscribed capacity must be contracted for consistent with the respective pipeline's tariff procedures which may require the Company to take expeditious procurement action to ensure it is available to serve customers. Beginning November 1, 2022, the Company participated in a right of first refusal open season on Algonquin that enables the Company the option to purchase supplies from Beverly, MA to various Company city-gates. For the 22/23 heating season, this transportation agreement with Algonquin will be supplied by a call option with Repsol Energy North America to deliver gas supplies into Beverly. MA. As a result of these procurement actions by the Company and as demonstrated in Chart G22-D and Chart G23-D (Base Case), the Company's current resource portfolio is sufficient to meet the Company's forecasted design-year and design day customer requirements in 2022/23 of the forecast period.[17]

[17] For modeling purposes, the Company assumes New England Market Area Supplies are available to flow on this Algonquin transportation capacity.

Beyond year 2022/23, while the Company is actively incentivizing electrification and energy efficiency on its system, the Company will nonetheless need additional resources. The ability to purchase incremental New England Market Area Supplies in order to meet the forecasted need may continue to be impacted by the state of the LNG market in New England. With few suppliers able to import LNG into New England and the lack of new gas pipeline infrastructure into New England from being able to access low cost Marcellus supplies in order to meet firm winter requirements, continued reliance on these deliveries to satisfy existing and forecasted requirements exposes customers to price volatility and supply reliability. As a result of Russia's invasion of Ukraine, New England LNG suppliers are continuing to compete at unprecedented levels with the global market for cargoes to be imported into the region. Further, on September 8, 2022, FERC held a New England Winter Gas-Electric Forum to bring together stakeholders in New England to discuss the challenges faced historically during New England winters and discuss the stakeholders' differing expectations of challenges for future winters. At that meeting, Constellation confirmed publicly that it does not have any commitments to remain open beyond winter 2023/24. Without a commitment from an anchor tenant, Constellation noted the possibility of shutting down its Everett terminal. In light of these challenges, the Company will continue to pursue available resources and incremental opportunities in order to meet customer requirements as needed.

IV.C.4 Gas Commodity

The Company contracts for quantities of gas to ensure sufficient supply to reliably meet design conditions, as well as to account for daily and seasonal load variations. The Company's portfolio contains a variety of transportation contracts utilized to transport baseload and swing supplies as well as underground storage supplies.

Supply contract durations are generally limited to a maximum term of one seasonal period. Baseload volumes are mainly one-month in duration, augmented with daily firm spot purchases allowing for the ability to respond to fluctuations in demand and maintain planned storage inventory targets.

During the winter, the Company looks to underground storage as its primary swing supply. However, since storage alone cannot account for all possible conditions, at times, transportation capacity is left open allowing for the flexibility to meet changing conditions (demand, weather, storage inventory level and/or price).

The Company's gas supply contracts are priced at various locations at market-based prices for both monthly and daily purchases. The Company primarily uses the North American Energy Standards Board form of standard contract which has been established with prospective, credit-worthy, reliable gas suppliers.

The Company also enters into Asset Management Arrangements ("AMA") for certain transportation assets in the portfolio. The Company limits AMA contract durations to one year. Utilizing the SENDOUT® Model, the Company determines the appropriate resource mix and establishes the baseload and swing volume requirements by month prior to issuing a request for proposals for AMAs. Below is a listing of the transportation assets that have been awarded under an AMA for the period of November 1, 2022 through October 31, 2023.

Pipeline	Contract No.	National Grid Entity	Receipt Point	Delivery Point	Quantity (MMBtu/ day)
Enbridge	M12197	Boston Gas	Dawn	Parkway	16,980
TransCanada	63478	Boston Gas	Parkway	Iroquois	16,793
Enbridge	M12273	Boston Gas	Dawn	Parkway	57,180
TransCanada	64272	Boston Gas	Parkway	East Hereford	57,180
Millennium	210162	Boston Gas	Corning-Empire PL	Ramapo AGT	25,000

AMAs are one of the tools the Company utilizes to reduce the overall cost of meeting customer requirements without compromising reliability of service. The Company also uses capacity release and off-system sales to manage its portfolio of resources in a cost-effective manner. The use of off-system sales, capacity release and AMA transactions enable the Company to maintain a portfolio designed to meet design day and design season requirements, while mitigating the costs associated with those assets when temporarily not needed to meet customer requirements.

IV.C.5 Pending Portfolio Additions

On May 13, 2016, the Department approved the Company's long term LNG strategy to develop commercial alternatives that will provide competitive options for the purchase of LNG for summer refill requirements. As part of this long term strategy, the Company entered into long term precedent agreements with each of NGLNG and Northeast Energy Center, LLC that enables to use the Company's pipeline transportation capacity on both Algonquin and Tennessee to transport volumes to the proposed liquefaction facility for liquefaction during the off-peak period. Each of the projects with NGLNG and Northeast Energy Center, LLC have received all necessary permits to commence construction and/or commissioning activities and are expected to be in service for the 2023 refill season.

IV.C.6 Future Portfolio Decisions

National Grid will be faced with decisions regarding the termination and/or, renewal of certain transportation, underground storage, and peaking contracts in its gas supply portfolio during the forecast period, as well as the need to address projected gaps between forecasted customer demand and available natural gas portfolio resources, which could include contracting for additional resources to the portfolio.

When faced with making these decisions, the Company will conduct an analysis to reach its conclusions on contract renewals, as well as the addition of new resources or pursuit of other alternatives. The Company will use an approach to long-term natural gas capacity options analysis that includes consideration of traditional gas resource options alongside the potential for incremental gas demand-side programs as "non-infrastructure" alternatives and consideration of portfolio decisions in light of the Commonwealth's "net zero" greenhouse gas emission reduction goal and related climate change policies and targets. This approach was demonstrated recently by the Company's affiliates in New York and Rhode Island.[18]

The Company's approach to future portfolio decisions continues to rely on several essential steps. First, the Company will evaluate the need to maintain the contracts as part of the resource portfolio. As part of this need analysis, the Company will consider among other things, current customer requirements as well as future forecasted customer requirements, including the impact of Capacity Exempt customers opting for sales service. Second, depending on the types of needed resources, the Company will 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. In addition, the Company will consult with competitive suppliers serving customers on National Grid's system to solicit their input on the Company's contract terminations, renewals and additions to the portfolio.

Finally, 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. Although price factors are the primary driver for contract portfolio decisions, the non-price factor of supply reliability cannot be understated. A diverse portfolio with supply sourcing options helps to mitigate both price and reliability issues.

IV.C.6.a Contract Approvals Required

The table below provides a listing of the Company's pipeline transportation, underground storage and LNG storage contracts, along with respective: MDQ, the Primary Term Expiration Date, the current termination dates, termination notification dates, and whether the Company is requesting Department approval of the renewal of the contract in this proceeding. Each of these agreements are subject to regulation by the FERC and, in the case of Enbridge and TransCanada, the Ontario Energy Board and Canada Energy Regulator. As such, renewal procedures including termination notice dates and any contractual right of first refusal are governed by the pipelines' tariff provisions and cannot be granted to the Company on a discriminatory basis.

Pursuant to FERC policy, it is only long-term firm shippers paying the maximum recourse rate that will automatically have a right of first refusal to continue service at the end of a contract's primary term. For shippers paying a negotiated rate, the right of first refusal is not inherent. In 2005, the Company signed a precedent agreement with Tennessee for firm transportation on the pipeline's ConneXion project to deliver supplies from the Gulf Coast to various city-gates in New England. The corresponding contract numbers are 64023 and 64024. The project

[18] See the *Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")*, February 2020, available at https://ngridlongtermsolutions.com/ and the *Aquidneck Island Long-Term Gas Capacity Study*, September 2020, available at https://www.nationalgridus.com/aquidneck-long-term-gas-capacity-study.

commenced service on November 1, 2007 with a primary term of twenty (20) years and was not negotiated to include any extension rights upon the end of the primary term. As a result, the Company does not currently have any right to continue firm service using this capacity after October 31, 2027 when it is expected to continue to be required. Along with other ConneXion customers, the Company engaged Tennessee in negotiations to amend the existing service agreements beyond October 31, 2027 at the maximum recourse rate on file with the FERC. Due to the competitive market demand for additional capacity in the New England market area, the forward value of adding the right of first refusal extension and the extension to the term of the capacity path associated with these contracts, Tennessee was willing to offer the Company continuation of these service agreements beyond the current contract expiry at a market-based rate. To avoid the possibility that this capacity may be remarketed to customers other than the Company, the Company entered into new negotiated rate agreements effective November 1, 2027, with a right to terminate without liability by November 1, 2023 should the Department not find continuation of this valuable service be necessary.

Shipper	Pipeline Company	Contract No.	Rate Schedule	MDQ	Primary Term Termination Date	Current Termination Date	Next Notice Date	Evergreen	Seeking Approval?
Boston Gas	Algonquin	99058	AFT-1	58,456	10/31/2021	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Algonquin	934001	AFT-1 (FTP)	20,771	10/31/1999	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Algonquin	93002CR	AFT-1 (F1/WS1)	44,699	10/31/2016	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Algonquin	9B100	AFT-1 (STB)	33,910	10/31/2021	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Algonquin	9221	AFT-1 (AFT2)	23,970	10/31/2021	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Algonquin	99012	AFT-1	35,000	10/31/2012	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Algonquin	510798	AFT-1	100,000	1/6/2032	1/6/2032	1/6/2031	Yes	N/A
Boston Gas	Algonquin	510807	AFT-CL	100,000	12/4/2031	12/4/2031	12/4/2030	Yes	N/A
Boston Gas	Algonquin	933003	AFT-1 (PSST)	2,222	3/31/2012	3/31/2024	3/31/2023	Yes	N/A
Boston Gas	Algonquin	93003ECR	AFT-E (F1)	112,057	10/31/2024	10/31/2025	10/31/2023	Yes	N/A
Boston Gas	Algonquin	98002C	AFT-E	7,327	10/31/2016	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Algonquin	510364	AFT-1	38,000	11/19/2022	11/19/2023	11/19/2022	Yes	N/A
Boston Gas	Algonquin	510365	AFT-CL	38,000	11/19/2022	11/19/2023	11/19/2022	Yes	N/A
Boston Gas	Algonquin	510366	AFT-CL	38,000	11/19/2022	11/19/2023	11/19/2022	Yes	N/A
Boston Gas	Algonquin	511110	AFT-1AB	19,000	10/31/2034	10/31/2034	10/31/2033	Yes	N/A
Boston Gas	Algonquin	511140	AFT-1AB	2,833	10/31/2022	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Algonquin	511178	AFT-1H	75,000	10/31/2023	10/31/2023	11/16/2022	Yes	N/A
Boston Gas	Eastern Gas	100015	FTNN	12,978	3/31/2027	3/31/2027	3/31/2026	Yes	N/A
Boston Gas	Eastern Gas	5G2191	FT-GSS	2,222	3/31/2027	3/31/2027	3/31/2026	Yes	N/A
Boston Gas	Eastern Gas	600051	GSSTE Storage	53,457	3/31/2027	3/31/2027	3/31/2025	Yes	N/A
Boston Gas	Eastern Gas	5F5800	GSS Storage	2,222	3/31/2027	3/31/2027	3/31/2025	Yes	N/A
Boston Gas	Eastern Gas	5F5801	GSS Storage	104	3/31/2027	3/31/2027	3/31/2025	Yes	N/A
Boston Gas	Enbridge	M12273	M12	57,180	10/31/2040	10/31/2040	10/31/2038	Yes	N/A
Boston Gas	Enbridge	M12197	M12	16,980	10/31/2017	10/31/2025	10/31/2023	Yes	N/A
Boston Gas	Honeoye		SS-NY Storage	6,150	4/1/1995	4/1/2024	4/1/2023	Yes	N/A

Boston Gas	Iroquois	42001	RTS-1	52,203	11/1/2011	11/1/2024	11/1/2023	Yes	N/A
Boston Gas	Millennium	210162	FT-1	50,000	3/31/2034	3/31/2034	9/30/2032	Negotiated Rate through Primary Term	N/A
Boston Gas	National Grid LNG, LP	LNG006	NGLNG	35,000	10/31/2009	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	PNGTS	233314	FT	57,068	10/31/2040	10/31/2040	10/31/2038	Negotiated Rate through Primary Term	N/A
Boston Gas	Tennessee	623	FT-A	74,515	10/31/2008	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Tennessee	2062	FT-A	152,537	10/31/2008	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Tennessee	20241	FT-A	58,627	10/31/2008	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Tennessee	109877	FT-A	43,200	3/31/2007	10/31/2027	10/31/2026	Yes	N/A
Boston Gas	Tennessee	330568	FT-A	13,868	10/21/2038	10/31/2038	10/31/2037	Yes	N/A
Boston Gas	Tennessee	256	FT-A	18,154	10/31/2008	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Tennessee	64023	FT-A	50,715	10/31/2027	10/31/2027	N/A	Negotiated Rate through Primary Term	N/A
Boston Gas	Tennessee	64024	FT-A	61,985	10/31/2027	10/31/2027	N/A	Negotiated Rate through Primary Term	N/A
Boston Gas	Tennessee	527	FS-MA Storage	95,415	10/31/2008	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Texas Eastern	331009	FTS-7	29,915	10/31/2006	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Texas Eastern	800285	FT-1	97,626	10/31/2024	10/31/2024	10/31/2023	Yes	N/A
Boston Gas	Texas Eastern	800286	CDS	43,347	10/31/2027	10/31/2027	10/31/2026	Yes	N/A
Boston Gas	Texas Eastern	800287	FT-1	23,720	4/30/2015	4/30/2028	4/30/2023	Yes	N/A
Boston Gas	Texas Eastern	400225	SS-1 Storage	75,740	4/30/2015	4/30/2028	4/30/2023	Yes	N/A
Boston Gas	Texas Eastern	331700	FTS-7	3,016	4/15/2005	4/15/2025	4/15/2023	Yes	N/A
Boston Gas	Texas Eastern	331800	FTS-8	985	3/31/2006	3/31/2025	3/31/2023	Yes	N/A
Boston Gas	TransCanada	64272	FT	57,180	10/31/2040	10/31/2040	10/31/2038	Yes	N/A
Boston Gas	TransCanada	63478	FT	16,793	10/31/2017	10/31/2026	10/31/2024	Yes	N/A
Boston Gas	Transco	1006425	FT	6,911	5/31/2008	5/31/2022	5/31/2021	Yes	N/A

The contracts listed in the table below have recently been consolidated[19].

Pipeline Company	**Contract No. Consolidated**	**Rate Schedule**	**New Contract No.**	**Consolidation Effective Date**
Algonquin	93002EA & 93003ECR	AFT-E1	93003ECR	7/1/2022
Texas Eastern	800286 & 800469	CDS	800286	11/1/2022

[19] The Company requested and received approval for consolidations requiring changes to contract terms in D.P.U. 20-132.

Texas Eastern	800285 & 800313	FT-1	800285	11/1/2022
Texas Eastern	800287 & 800400	FT-1	800287	10/1/2022
Texas Eastern	400200 & 400225	SS-1	400225	7/1/2022
Tennessee	524 & 527	FS-MA	527	12/1/2021
Eastern Gas	600020 & 561286	GSSTE	600051	4/1/2022

IV.D.1 Base Case

On a design day, the Company relies on all of its available resources to meet customer requirements and there is no "back-up" capacity to ensure deliveries at the Company's citygates. Therefore, the resource portfolio must have sufficient resources to meet design-day sendout requirements. The Company's resource plan is sufficient to meet base-case design-day load requirements in 2022/23. From a planning perspective, a capacity shortfall is signaled where the analysis shows that resources are required on a peak day. Beyond the first year, incremental resources are needed to meet requirements on the design day. The table below provides a summary of incremental resources required on the design day (see Table G23-D/Base Case for details):

Incremental Requirement: Base Case/Design Day

YEAR	Capacity Resources (BBtu)
2022/23	0
2023/24	4
2024/25	47
2025/26	65
2026/27	96

The Company's resource plan is sufficient to meet base-case design-year load requirements in 2022/23. Beyond, the first year, incremental resources are needed to meet requirements during the peak period. The table below provides a summary of incremental resources required (see Table G22-D/Base Case for details):

Incremental Requirement: Base Case/Heating Season

YEAR	Volume (BBtu)
2022/23	0
2023/24	541
2024/25	376
2025/26	917
2026/27	1,361

IV.D.2 High-Demand Case

The incremental resource need for the High-Demand case (design day) is summarized below (see Table G23-D/High-Demand Case for details):

Incremental Requirement: High Case/Design Day

YEAR	Capacity Resources (BBtu)
2022/23	0
2023/24	23
2024/25	70
2025/26	95
2026/27	129

The incremental resource need for the High-Demand case (design season) is summarized below (see Table G22-D/High-Demand Case for details):

Incremental Requirement: High Case/Heating Season

YEAR	Volume (BBtu)
2022/23	0
2023/24	629
2024/25	929
2025/26	1,525
2026/27	2,176

IV.D.3 Low-Demand Case

The incremental resource need for the Low-Demand case (design day) is summarized below (see Table G23-D/Low-Demand Case for details):

Incremental Requirement: Low Case/Design Day

YEAR	Capacity Resources (BBtu)
2022/23	0
2023/24	0
2024/25	0
2025/26	1
2026/27	9

The incremental resource need for the Low-Demand case (design season) is summarized below (see Table G22-D/Low-Demand Case for details):

Incremental Resources: Low Case/Heating Season

YEAR	Volume (BBtu)
2022/23	0
2023/24	262
2024/25	294
2025/26	543
2026/27	372

IV.D.4 Cold Snap Analysis

In addition to the design-day, design-year and normal-year planning standards, the Company also evaluates the capability of the resource portfolio to meet sendout requirements during a protracted period of very cold weather, which is referred to as a "cold snap". The cold-snap evaluation is performed by modeling daily sendout and observing the predicted resource usage over a specified set of EDD. 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 (9 January - 22 January) to test the adequacy of inventories and refill requirements.

From the evaluation of 40 years of January weather data from 1976-2015, the mean total EDD for the period 14 January - 27 January is 586.4 EDD with a standard deviation of 103.8 EDD. 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 800 EDD, 6 EDD warmer than the Jan 1982 figure of 806 EDD and just 4 EDD warmer colder than what occurred in January 2004 and January 2005. In comparison, the cold snap that occurred between 25 Dec 2017 and 7 Jan 2018 represented 824 EDD or, at the time, a once-in-90-year occurrence.

The Company assumed normal weather through 8 January, followed by the 14-day cold snap period, then followed by normal weather after the cold snap interval. Chart IV-D-1 shows the normal EDD pattern for the period January 1-31, with the cold-snap scenario highlighted in black. Using base-case demand, the Company's resource plan shows that it has adequate resources available to meet cold snap sendout requirements in year 2022/23. For 2023/24 through 2026/27, incremental resources will be needed to meet design season requirements.

V. Summary of Compliance with D.P.U. 20-132

In its order dated October 20, 2021 in Boston Gas Company d/b/a National Grid, D.P.U. 20-132, the Department approved the Company's Long-Range Forecast and Supply Plan. The Department did not require any compliance items to be included in the Company's next Forecast and Supply Plan.

Table DD
National Grid
2022 Long-Range Resource and Requirements Plan

Effective Degree Day Data

Split Year 11/1 to 10/31	Heating Season (Nov-Mar)	Non-Heating Season (Apr-Oct)	Total Split Year	Design Day
2005/06	4,730	1,398	6,128	79
2006/07	4,666	1,274	5,940	79
2007/08	4,867	1,343	6,210	79
2008/09	5,096	1,446	6,542	79
2009/10	4,623	998	5,621	79
2010/11	5,016	1,190	6,206	78
2011/12	3,875	1,094	4,969	78
2012/13	4,808	1,271	6,079	78
2013/14	5,311	1,229	6,540	78
2014/15	5,468	1,291	6,759	78
2015/16	4,146	1,348	5,494	78
2016/17	4,713	1,135	5,848	78
2017/18	5,026	1,368	6,394	78
2018/19	4,771	1,099	5,870	78
2019/20	4,338	1,531	5,869	78
2020/21	4,610	918	5,528	78
2021/22	4,651	#N/A	#N/A	78
Normal	*4,815*	*1,297*	*6,112*	---
Design	*5,564*	*1,496*	*7,060*	*78*

	Time Period Analyzed	Method Used	Recurrence Expectancy
Normal Year	1/2002 - 12/2021	Average	N/A
Design Year	1982-2021	See text	Once in 34.42 years
Design Day	1982-2021	See text	Once in 57.80 years

TABLE G-1

Company: National Grid
Filing Date: November 1, 2022

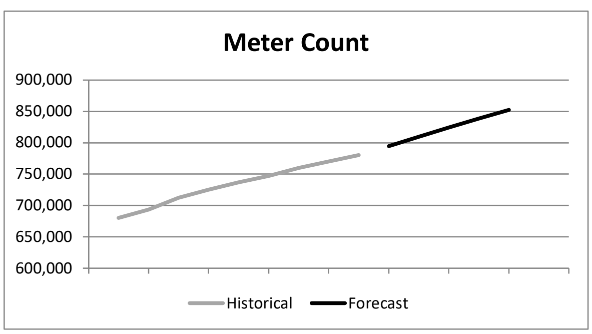
SENDOUT BY RATE CLASS
RESIDENTIAL HEATING

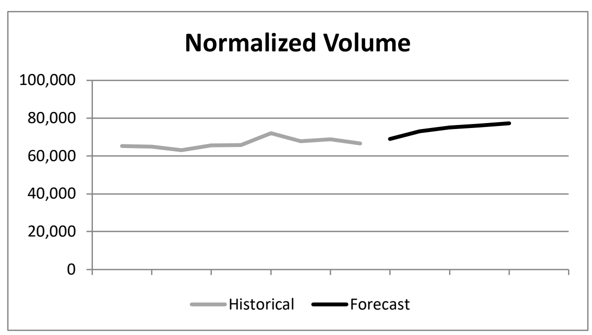
BASE CASE

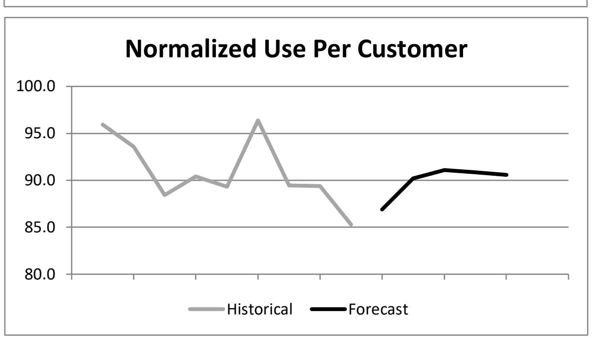
		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	680,154	48,261	20,263	*44,471*	*20,783*	X	X	0.0112	27.3	*95.9*
2014-2015	693,459	49,662	20,260	*44,594*	*20,307*	X	X	0.0112	25.2	*93.6*
2015-2016	712,632	38,843	19,300	*44,125*	*18,897*	X	X	0.0111	20.7	*88.4*
2016-2017	725,173	42,407	21,299	*43,120*	*22,433*	X	X	0.0097	31.4	*90.4*
2017-2018	737,184	46,609	21,411	*44,972*	*20,861*	X	X	0.0105	25.0	*89.3*
2018-2019	747,139	49,374	20,521	*49,758*	*22,251*	X	X	0.0117	24.9	*96.4*
2019-2020	759,736	44,407	21,359	*48,703*	*19,252*	X	X	0.0119	17.0	*89.4*
2020-2021	769,959	45,333	18,746	*46,994*	*21,817*	X	X	0.0105	25.0	*89.4*
2021-2022	780,582	44,831	20,396	*46,167*	*20,396*	X	X	0.0104	21.5	*85.3*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	794,592	X	X	47,738	21,312	54,254	23,065	0.0106	22.4	*86.9*
2023-2024	809,493	X	X	50,568	22,461	57,485	24,322	0.0110	23.0	*90.2*
2024-2025	824,330	X	X	52,528	22,551	59,824	24,514	0.0114	21.5	*91.1*
2025-2026	838,829	X	X	53,385	22,819	60,813	24,817	0.0114	21.2	*90.8*
2026-2027	852,509	X	X	54,173	23,046	61,726	25,077	0.0114	20.9	*90.6*

X : Not required







SENDOUT BY RATE CLASS
RESIDENTIAL NON-HEATING

BASE CASE

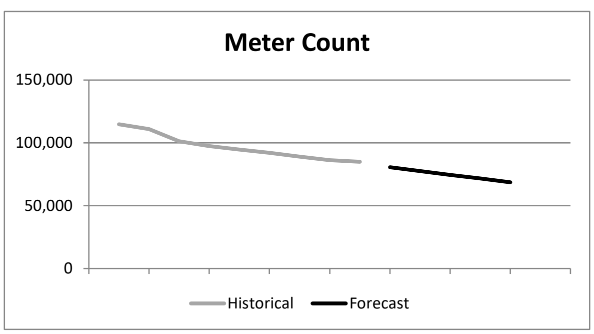
Historical Retail Sendout (MDth)

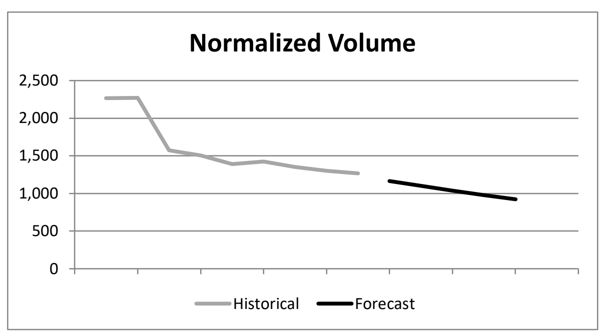
	Average No. of Customers	ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	114,938	1,309	1,016	*1,243*	*1,025*	X	X	0.0012	12.7	*19.7*
2014-2015	111,170	1,379	989	*1,281*	*990*	X	X	0.0013	12.2	*20.4*
2015-2016	101,282	781	741	*835*	*737*	X	X	0.0008	10.6	*15.5*
2016-2017	97,495	763	724	*769*	*735*	X	X	0.0007	11.4	*15.4*
2017-2018	94,713	731	678	*717*	*673*	X	X	0.0007	10.7	*14.7*
2018-2019	92,112	754	656	*757*	*671*	X	X	0.0008	10.7	*15.5*
2019-2020	89,130	680	657	*711*	*641*	X	X	0.0007	10.6	*15.2*
2020-2021	86,185	679	583	*692*	*608*	X	X	0.0008	10.3	*15.1*
2021-2022	85,020	681	574	*693*	*574*	X	X	0.0009	9.6	*14.9*

Forecast Retail Sendout (MDth)

	Average No. of Customers	ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	80,651	X	X	629	534	680	547	0.0008	9.5	*14.4*
2023-2024	77,554	X	X	595	504	643	517	0.0008	9.3	*14.2*
2024-2025	74,589	X	X	564	473	610	485	0.0008	9.1	*13.9*
2025-2026	71,624	X	X	534	444	578	456	0.0008	8.8	*13.7*
2026-2027	68,659	X	X	505	417	547	428	0.0008	8.6	*13.4*

X : Not required





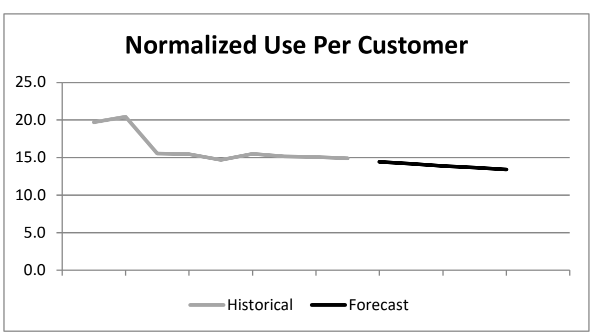


TABLE G-3 (A)

Company: National Grid
Filing Date: November 1, 2022

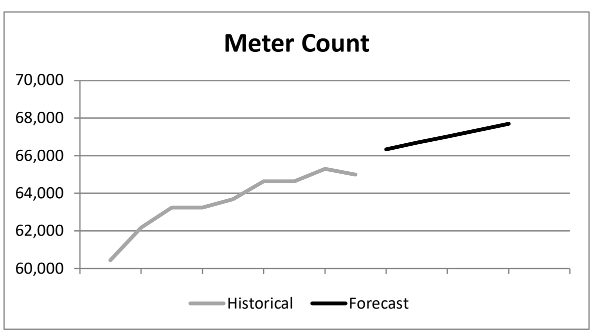
SENDOUT BY RATE CLASS
COMMERCIAL, FIRM

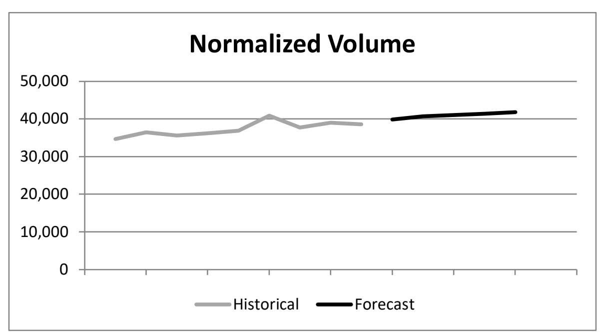
BASE CASE

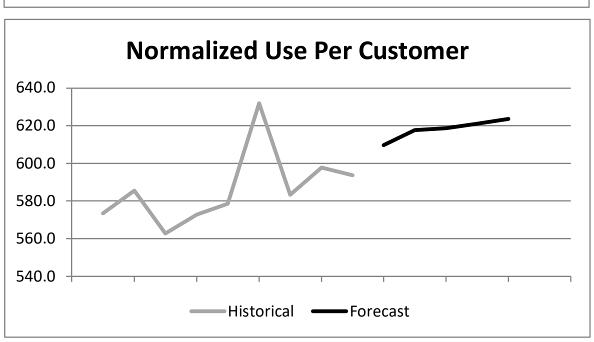
	Average No. of Customers	Historical Retail Sendout (MDth)						Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
		ACTUAL		NORMAL		DESIGN				
		Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season			
2013-2014	60,439	25,696	10,709	*23,672*	*10,987*	X	X	0.0675	160.6	*573.4*
2014-2015	62,183	27,873	11,352	*25,027*	*11,379*	X	X	0.0701	157.0	*585.5*
2015-2016	63,245	21,985	10,835	*24,987*	*10,607*	X	X	0.0710	129.1	*562.8*
2016-2017	63,243	23,440	11,764	*23,835*	*12,391*	X	X	0.0612	198.8	*572.8*
2017-2018	63,696	25,874	12,173	*24,976*	*11,870*	X	X	0.0668	170.0	*578.5*
2018-2019	64,643	27,759	11,924	*27,972*	*12,883*	X	X	0.0749	174.2	*632.0*
2019-2020	64,630	25,141	11,280	*27,657*	*10,046*	X	X	0.0816	84.6	*583.4*
2020-2021	65,302	25,676	10,684	*26,615*	*12,419*	X	X	0.0701	169.3	*597.7*
2021-2022	64,999	26,029	11,784	*26,806*	*11,784*	X	X	0.0729	147.9	*593.7*

	Average No. of Customers	Forecast Retail Sendout (MDth)						Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
		Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season			
2022-2023	66,338	X	X	27,826	12,062	31,674	13,097	0.0757	147.0	*609.7*
2023-2024	66,688	X	X	28,399	12,337	32,323	13,392	0.0766	149.7	*617.8*
2024-2025	67,022	X	X	28,643	12,395	32,607	13,461	0.0769	148.5	*618.6*
2025-2026	67,357	X	X	28,911	12,516	32,912	13,592	0.0772	149.3	*621.2*
2026-2027	67,699	X	X	29,162	12,631	33,196	13,716	0.0775	150.1	*623.6*

X : Not required







SENDOUT BY RATE CLASS
INDUSTRIAL, FIRM

BASE CASE

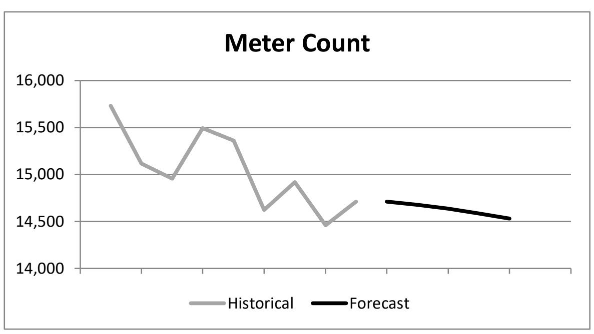
Historical Retail Sendout (MDth)

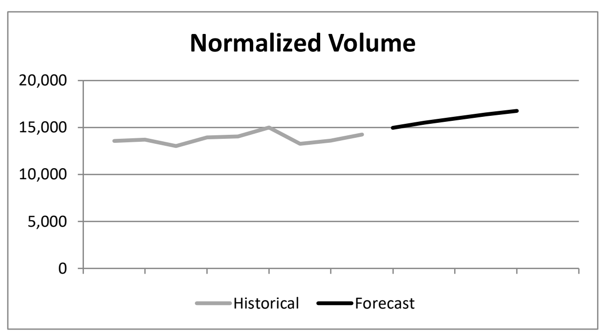
	Average No. of Customers	ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	15,731	6,816	6,949	*6,603*	*6,978*	X	X	0.0274	696.0	*863.3*
2014-2015	15,116	6,905	7,075	*6,631*	*7,078*	X	X	0.0278	737.2	*906.9*
2015-2016	14,956	5,990	6,812	*6,238*	*6,793*	X	X	0.0248	719.9	*871.3*
2016-2017	15,495	6,445	7,428	*6,476*	*7,478*	X	X	0.0199	779.2	*900.6*
2017-2018	15,359	6,869	7,312	*6,780*	*7,282*	X	X	0.0274	748.0	*915.6*
2018-2019	14,624	7,320	7,574	*7,342*	*7,672*	X	X	0.0338	820.0	*1026.7*
2019-2020	14,917	6,821	6,251	*7,174*	*6,078*	X	X	0.0496	585.3	*888.4*
2020-2021	14,460	6,327	7,083	*6,396*	*7,210*	X	X	0.0232	799.1	*941.0*
2021-2022	14,712	6,696	7,508	*6,757*	*7,508*	X	X	0.0254	814.1	*969.6*

Forecast Retail Sendout (MDth)

	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2020-2021	14,710	X	X	7,107	7,853	7,419	7,937	0.0273	850.1	*1017.0*
2021-2022	14,679	X	X	7,358	8,147	7,678	8,234	0.0281	884.5	*1056.3*
2022-2023	14,636	X	X	7,557	8,401	7,881	8,489	0.0285	915.9	*1090.3*
2023-2024	14,585	X	X	7,753	8,643	8,082	8,731	0.0291	946.4	*1124.1*
2024-2025	14,532	X	X	7,926	8,855	8,260	8,945	0.0296	973.9	*1154.8*

X : Not required





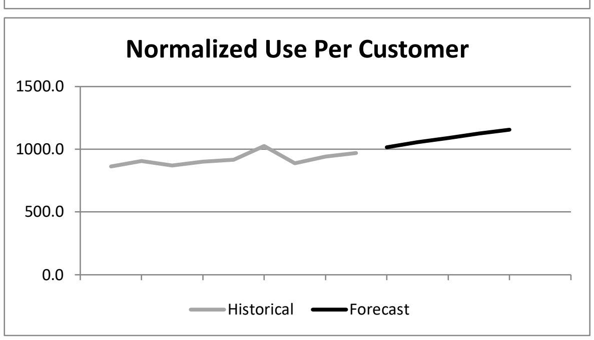


TABLE G-3 (C)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
G7, G17, COMPANY USE, OTHER CUSTOMER CHOICE

BASE CASE

		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	29	311	418	*309*	*418*	X	X	0.1262	24102.8	*24873.8*
2014-2015	17	711	785	*688*	*786*	X	X	1.9905	73273.8	*85439.9*
2015-2016	16	733	969	*743*	*968*	X	X	0.9408	99544.5	*105294.9*
2016-2017	17	1,067	1,035	*1,075*	*1,049*	X	X	4.9398	91753.8	*121945.9*
2017-2018	17	972	1,081	*961*	*1,077*	X	X	3.0204	100835.1	*119296.0*
2018-2019	17	985	1,027	*988*	*1,040*	X	X	3.8326	95869.0	*119294.0*
2019-2020	17	998	1,008	*1,040*	*988*	X	X	5.1710	87668.7	*119274.2*
2020-2021	17	967	1,061	*978*	*1,082*	X	X	3.2774	102336.0	*122367.7*
2021-2022	16	1,010	966	*1,025*	*966*	X	X	5.5026	90750.7	*124382.4*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2023-2024	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2024-2025	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2025-2026	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2026-2027	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*

X : Not required

TABLE G-4 (A)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
INTERRUPTIBLE

BASE CASE

	Average No. of Customers	Historical Retail Sendout (MDth)						Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
		ACTUAL		NORMAL		DESIGN				
		Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season			
2013-2014	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2014-2015	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2015-2016	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2016-2017	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2017-2018	0	0	0	0	0	X	X	0.0000	0.0	0.0
2018-2019	0	0	0	0	0	X	X	0.0000	0.0	0.0
2019-2020	0	0	0	0	0	X	X	0.0000	0.0	0.0
2020-2021	0	0	0	0	0	X	X	0.0000	0.0	0.0
2021-2022	0	0	0	0	0	X	X	0.0000	0.0	0.0

	Average No. of Customers	Forecast Retail Sendout (MDth)						Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
		Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season			
2022-2023	0	X	X	0	0	0	0	0.0000	0.0	0.0
2023-2024	0	X	X	0	0	0	0	0.0000	0.0	0.0
2024-2025	0	X	X	0	0	0	0	0.0000	0.0	0.0
2025-2026	0	X	X	0	0	0	0	0.0000	0.0	0.0
2026-2027	0	X	X	0	0	0	0	0.0000	0.0	0.0

X : Not required

TABLE G-4 (B)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
SALES FOR RESALE, FIRM

BASE CASE

Historical Retail Sendout (MDth)

	Average No. of Customers	ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2014-2015	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2015-2016	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2016-2017	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2017-2018	0	0	0	0	0	X	X	0.0000	0.0	0.0
2018-2019	0	0	0	0	0	X	X	0.0000	0.0	0.0
2019-2020	0	0	0	0	0	X	X	0.0000	0.0	0.0
2020-2021	0	0	0	0	0	X	X	0.0000	0.0	0.0
2021-2022	0	0	0	0	0	X	X	0.0000	0.0	0.0

Forecast Retail Sendout (MDth)

	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	0	X	X	0	0	0	0	0.0000	0.0	0.0
2023-2024	0	X	X	0	0	0	0	0.0000	0.0	0.0
2024-2025	0	X	X	0	0	0	0	0.0000	0.0	0.0
2025-2026	0	X	X	0	0	0	0	0.0000	0.0	0.0
2026-2027	0	X	X	0	0	0	0	0.0000	0.0	0.0

X : Not required

TABLE G-4 (C)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
UNACCOUNTED FOR

BASE CASE

	Average No. of Customers	Historical (MDth) ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	X	11,778	-4,866	X	X	X	X	X	X	X
2014-2015	X	12,689	-6,615	X	X	X	X	X	X	X
2015-2016	X	6,124	-3,613	X	X	X	X	X	X	X
2016-2017	X	11,038	-8,444	X	X	X	X	X	X	X
2017-2018	X	11,947	-4,763	X	X	X	X	X	X	X
2018-2019	X	7,199	-5,106	X	X	X	X	X	X	X
2019-2020	X	7,610	-2,937	X	X	X	X	X	X	X
2020-2021	X	6,013	-3,937	X	X	X	X	X	X	X
2021-2022	X	8,669	307	9,040	307	X	X	X	X	X

	Average No. of Customers	Forecast (MDth) Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	X	X	X	9,181	590	12,710	1,204	X	X	X
2023-2024	X	X	X	9,146	336	12,704	916	X	X	X
2024-2025	X	X	X	9,668	622	13,218	1,132	X	X	X
2025-2026	X	X	X	9,665	666	13,224	1,173	X	X	X
2026-2027	X	X	X	9,741	784	13,315	1,288	X	X	X

X : Not required

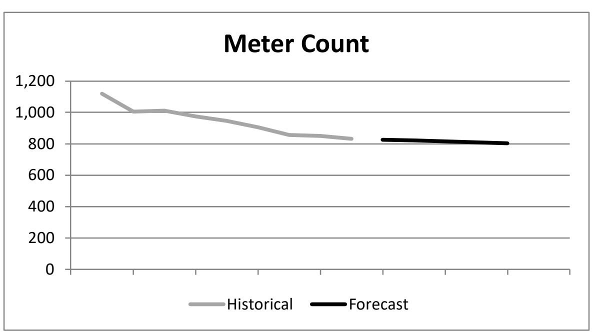
SENDOUT BY RATE CLASS
CAPACITY-EXEMPT VOLUMES (EXCLUDING POWERPLANTS)

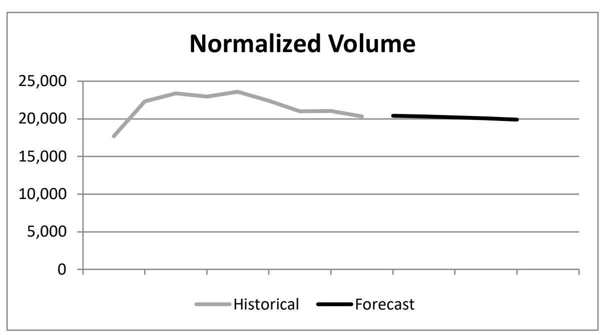
BASE CASE

		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	1,120	9,973	8,114	*9,499*	*8,179*	X	X	0.8534	10566.5	*15782.2*
2014-2015	1,006	10,993	11,716	*10,603*	*11,719*	X	X	0.5949	18556.5	*22192.5*
2015-2016	1,011	10,876	12,062	*11,372*	*12,024*	X	X	0.7326	18671.0	*23148.5*
2016-2017	976	11,489	11,219	*11,582*	*11,367*	X	X	0.9359	17797.9	*23518.1*
2017-2018	946	11,875	11,936	*11,696*	*11,876*	X	X	0.8987	19418.2	*24910.9*
2018-2019	907	11,300	10,880	*11,340*	*11,060*	X	X	1.0002	18592.9	*24706.0*
2019-2020	856	10,819	9,922	*11,378*	*9,647*	X	X	1.3690	16192.5	*24559.6*
2020-2021	850	10,646	9,838	*10,837*	*10,192*	X	X	1.0995	18016.0	*24735.9*
2021-2022	832	10,264	9,885	*10,408*	*9,885*	X	X	1.0585	17931.3	*24400.8*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	825	X	X	10,511	9,881	11,217	10,071	1.0995	17985.8	*24705.8*
2023-2024	822	X	X	10,469	9,859	11,169	10,047	1.0964	18041.6	*24742.7*
2024-2025	814	X	X	10,385	9,805	11,076	9,990	1.0915	18118.7	*24790.1*
2025-2026	810	X	X	10,301	9,751	10,982	9,934	1.0835	18145.6	*24767.6*
2026-2027	804	X	X	10,207	9,686	10,879	9,867	1.0760	18173.6	*24750.3*

X : Not required





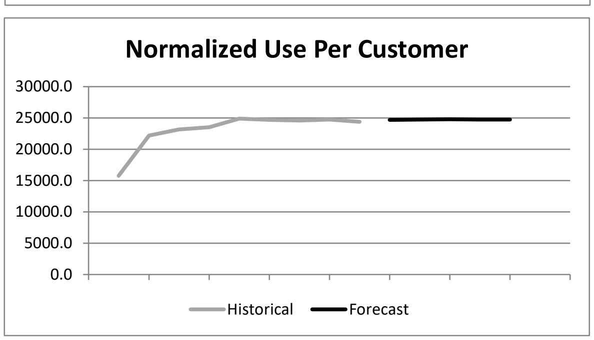


TABLE G-5 (A)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
TOTAL RETAIL VOLUMES (EXCLUDING POWERPLANTS)

BASE CASE

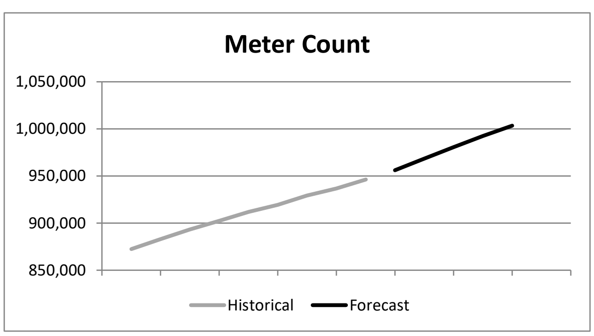
Historical Retail Sendout (MDth)

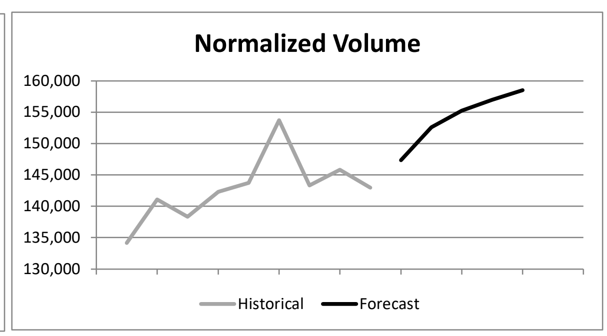
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	872,411	92,367	47,469	*85,796*	*48,370*	X	X	0.0152	61.0	*153.8*
2014-2015	882,951	97,523	52,178	*88,824*	*52,258*	X	X	0.0151	67.6	*159.8*
2015-2016	893,142	79,208	50,719	*88,301*	*50,026*	X	X	0.0152	61.9	*154.9*
2016-2017	902,399	85,610	53,469	*86,859*	*55,451*	X	X	0.0136	74.8	*157.7*
2017-2018	911,914	92,930	54,590	*90,103*	*53,639*	X	X	0.0147	67.8	*157.6*
2018-2019	919,442	97,493	52,584	*98,158*	*55,576*	X	X	0.0164	66.7	*167.2*
2019-2020	929,286	88,865	50,478	*96,662*	*46,653*	X	X	0.0176	46.7	*154.2*
2020-2021	936,773	89,628	47,995	*92,513*	*53,329*	X	X	0.0150	63.9	*155.7*
2021-2022	946,160	89,510	51,113	*91,856*	*51,113*	X	X	0.0151	58.7	*151.1*

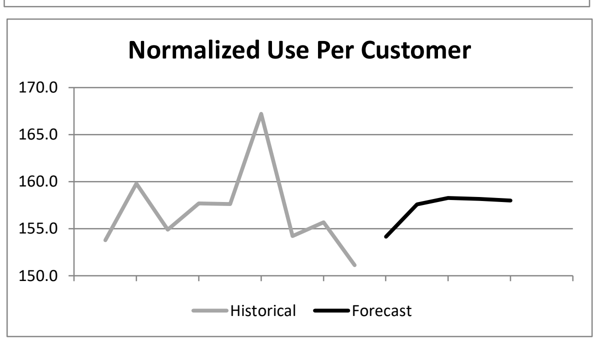
Forecast Retail Sendout (MDth)

	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	956,214	X	X	94,775	52,607	106,262	55,697	0.0155	59.6	*154.1*
2023-2024	968,505	X	X	98,352	54,274	110,318	57,492	0.0159	60.4	*157.6*
2024-2025	980,724	X	X	100,639	54,590	113,016	57,919	0.0162	59.0	*158.3*
2025-2026	992,552	X	X	101,847	55,138	114,387	58,511	0.0163	58.8	*158.2*
2026-2027	1,003,542	X	X	102,936	55,600	115,628	59,014	0.0163	58.5	*158.0*

X : Not required







Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
TOTAL WHOLESALE VOLUMES (EXCLUDING POWERPLANTS)

BASE CASE

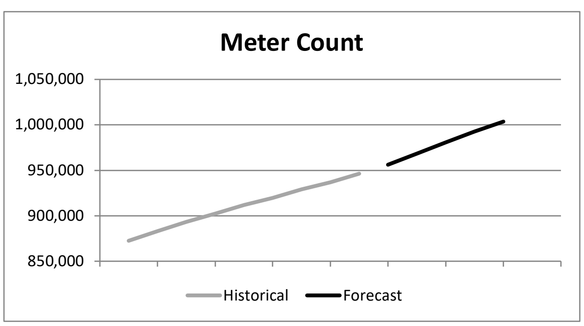
Historical Wholesale Sendout (MDth)

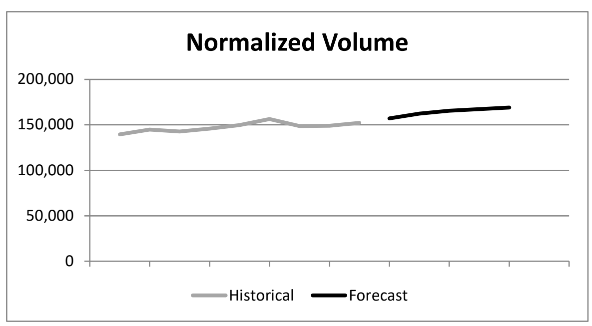
	Average No. of Customers	ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)	Actual Peak Day (MMBtu)
2013-2014	872,411	104,145	42,603	*95,876*	*43,737*	X	X	0.0191	43.2	*160.0*	1,225,493
2014-2015	882,951	110,212	45,563	*99,026*	*45,666*	X	X	0.0194	45.3	*163.9*	1,211,969
2015-2016	893,142	85,332	47,107	*96,241*	*46,275*	X	X	0.0183	48.0	*159.6*	1,287,533
2016-2017	902,399	96,648	45,024	*98,340*	*47,711*	X	X	0.0184	49.5	*161.8*	1,115,301
2017-2018	911,914	104,877	49,827	*101,254*	*48,608*	X	X	0.0188	49.3	*164.3*	1,356,014
2018-2019	919,442	104,691	47,478	*105,475*	*51,006*	X	X	0.0194	51.7	*170.2*	1,342,428
2019-2020	929,286	96,475	47,541	*105,689*	*43,021*	X	X	0.0208	33.0	*160.0*	1,091,737
2020-2021	936,773	95,640	44,058	*98,980*	*50,232*	X	X	0.0174	53.0	*159.3*	1,177,839
2021-2022	946,160	98,178	51,419	*100,896*	*51,419*	X	X	0.0175	54.0	*161.0*	1,225,003

Forecast Wholesale Sendout (MDth)

	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)	Design Day (MMBtu)
2022-2023	956,214	X	X	103,955	53,197	118,972	56,901	0.0178	55.5	*164.3*	1,576,391
2023-2024	968,505	X	X	107,498	54,609	123,022	58,408	0.0183	55.8	*167.4*	1,630,517
2024-2025	980,724	X	X	110,308	55,212	126,234	59,052	0.0187	54.8	*168.8*	1,673,933
2025-2026	992,552	X	X	111,511	55,804	127,611	59,684	0.0186	54.7	*168.6*	1,693,353
2026-2027	1,003,542	X	X	112,677	56,384	128,944	60,302	0.0186	54.6	*168.5*	1,712,156

X : Not required





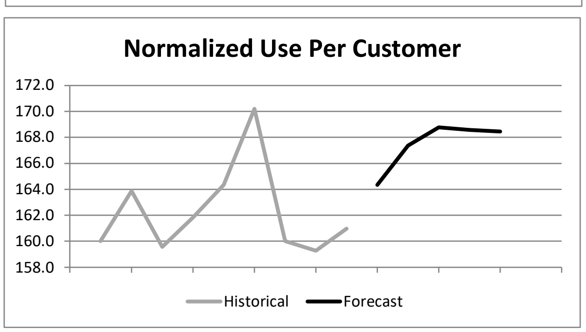


TABLE G-1

Company: National Grid
Filing Date: November 1, 2022

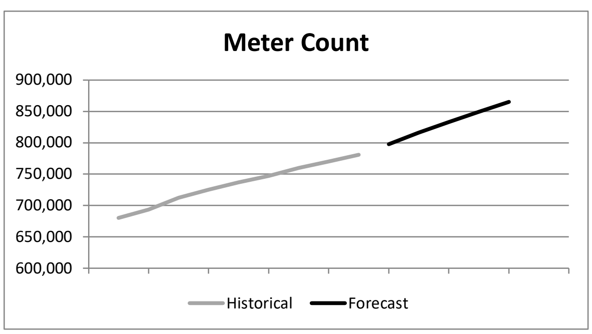
SENDOUT BY RATE CLASS
RESIDENTIAL HEATING

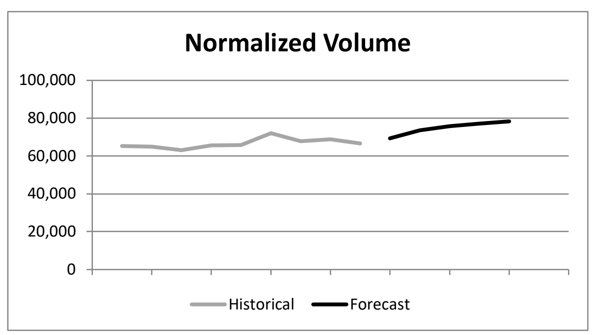
HIGH CASE

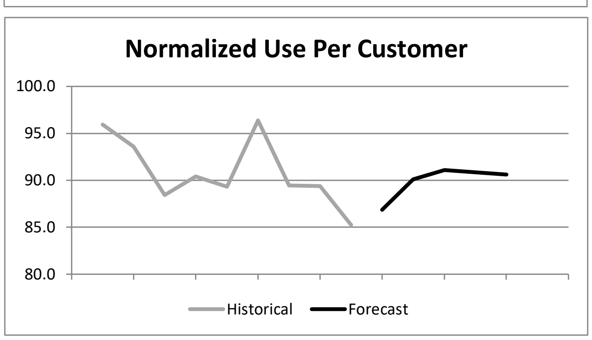
		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	680,154	48,261	20,263	*44,471*	*20,783*	X	X	0.0112	27.3	*95.9*
2014-2015	693,459	49,662	20,260	*44,594*	*20,307*	X	X	0.0112	25.2	*93.6*
2015-2016	712,632	38,843	19,300	*44,125*	*18,897*	X	X	0.0111	20.7	*88.4*
2016-2017	725,173	42,407	21,299	*43,120*	*22,433*	X	X	0.0097	31.4	*90.4*
2017-2018	737,184	46,609	21,411	*44,972*	*20,861*	X	X	0.0105	25.0	*89.3*
2018-2019	747,139	49,374	20,521	*49,758*	*22,251*	X	X	0.0117	24.9	*96.4*
2019-2020	759,736	44,407	21,359	*48,703*	*19,252*	X	X	0.0119	17.0	*89.4*
2020-2021	769,959	45,333	18,746	*46,994*	*21,817*	X	X	0.0105	25.0	*89.4*
2021-2022	780,774	44,830	20,402	*46,166*	*20,402*	X	X	0.0104	21.5	*85.3*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	797,700	X	X	47,881	21,415	54,410	23,171	0.0105	22.5	*86.9*
2023-2024	816,170	X	X	50,925	22,609	57,893	24,483	0.0110	22.9	*90.1*
2024-2025	832,933	X	X	53,078	22,795	60,448	24,778	0.0114	21.5	*91.1*
2025-2026	849,363	X	X	54,054	23,119	61,573	25,141	0.0114	21.2	*90.9*
2026-2027	865,309	X	X	54,992	23,406	62,659	25,468	0.0114	20.9	*90.6*

X : Not required







SENDOUT BY RATE CLASS
RESIDENTIAL NON-HEATING

HIGH CASE

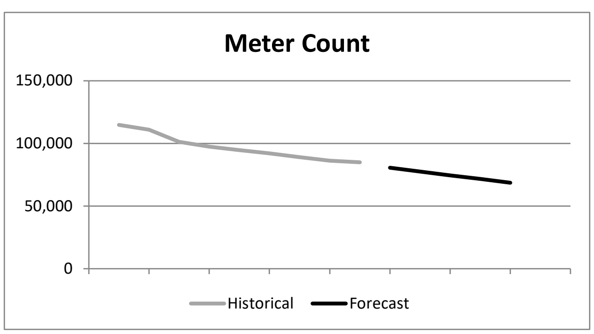
Historical Retail Sendout (MDth)

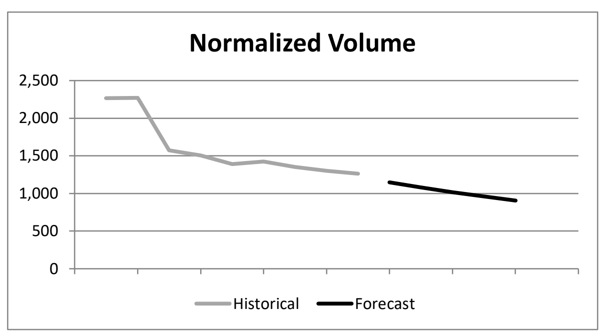
	Average No. of Customers	ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	114,938	1,309	1,016	*1,243*	*1,025*	X	X	0.0012	12.7	*19.7*
2014-2015	111,170	1,379	989	*1,281*	*990*	X	X	0.0013	12.2	*20.4*
2015-2016	101,282	781	741	*835*	*737*	X	X	0.0008	10.6	*15.5*
2016-2017	97,495	763	724	*769*	*735*	X	X	0.0007	11.4	*15.4*
2017-2018	94,713	731	678	*717*	*673*	X	X	0.0007	10.7	*14.7*
2018-2019	92,112	754	656	*757*	*671*	X	X	0.0008	10.7	*15.5*
2019-2020	89,130	680	657	*711*	*641*	X	X	0.0007	10.6	*15.2*
2020-2021	86,185	679	583	*692*	*608*	X	X	0.0008	10.3	*15.1*
2021-2022	85,020	680	572	*692*	*572*	X	X	0.0009	9.6	*14.9*

Forecast Retail Sendout (MDth)

	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	80,651	X	X	620	529	669	542	0.0008	9.4	*14.2*
2023-2024	77,554	X	X	581	496	627	509	0.0008	9.2	*13.9*
2024-2025	74,589	X	X	550	467	594	478	0.0008	9.0	*13.6*
2025-2026	71,624	X	X	521	438	563	450	0.0008	8.8	*13.4*
2026-2027	68,659	X	X	493	411	533	422	0.0008	8.5	*13.2*

X : Not required





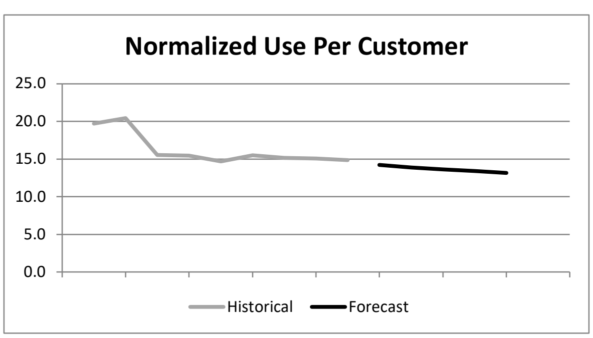


TABLE G-3 (A)

Company: National Grid
Filing Date: November 1, 2022

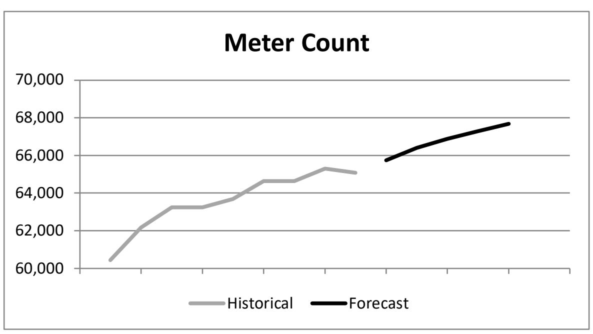
SENDOUT BY RATE CLASS
COMMERCIAL, FIRM

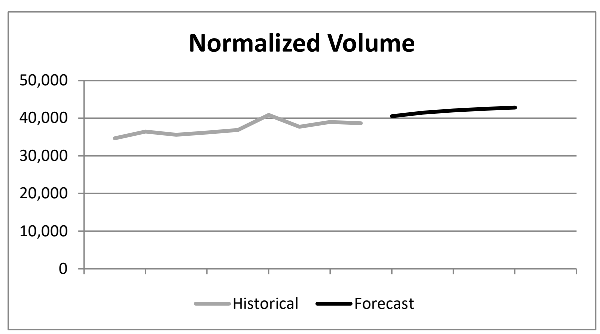
HIGH CASE

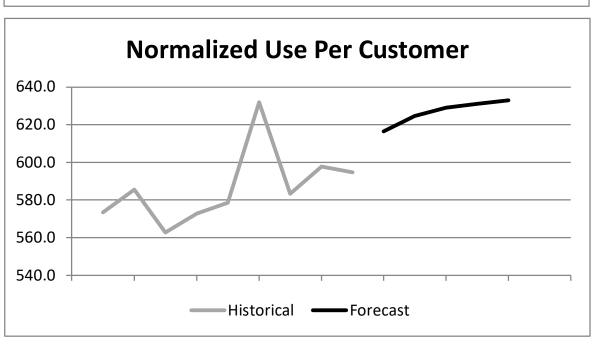
		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	60,439	25,696	10,709	*23,672*	*10,987*	X	X	0.0675	160.6	*573.4*
2014-2015	62,183	27,873	11,352	*25,027*	*11,379*	X	X	0.0701	157.0	*585.5*
2015-2016	63,245	21,985	10,835	*24,987*	*10,607*	X	X	0.0710	129.1	*562.8*
2016-2017	63,243	23,440	11,764	*23,835*	*12,391*	X	X	0.0612	198.8	*572.8*
2017-2018	63,696	25,874	12,173	*24,976*	*11,870*	X	X	0.0668	170.0	*578.5*
2018-2019	64,643	27,759	11,924	*27,972*	*12,883*	X	X	0.0749	174.2	*632.0*
2019-2020	64,630	25,141	11,280	*27,657*	*10,046*	X	X	0.0816	84.6	*583.4*
2020-2021	65,302	25,676	10,684	*26,615*	*12,419*	X	X	0.0701	169.3	*597.7*
2021-2022	65,077	26,072	11,853	*26,849*	*11,853*	X	X	0.0728	149.5	*594.7*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	65,752	X	X	28,275	12,262	32,184	13,314	0.0765	148.8	*616.5*
2023-2024	66,404	X	X	28,968	12,518	32,980	13,597	0.0778	149.5	*624.8*
2024-2025	66,873	X	X	29,387	12,687	33,458	13,782	0.0784	150.3	*629.2*
2025-2026	67,280	X	X	29,650	12,808	33,757	13,912	0.0786	150.9	*631.1*
2026-2027	67,676	X	X	29,903	12,928	34,044	14,042	0.0787	151.6	*632.9*

X : Not required







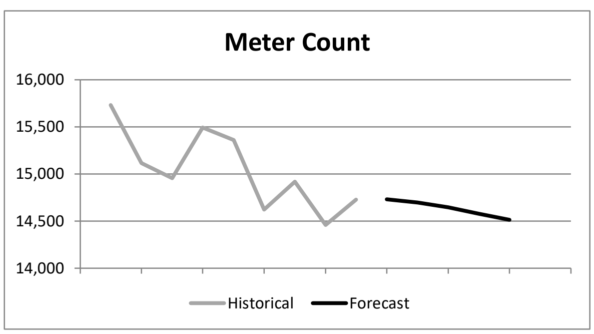
SENDOUT BY RATE CLASS
INDUSTRIAL, FIRM

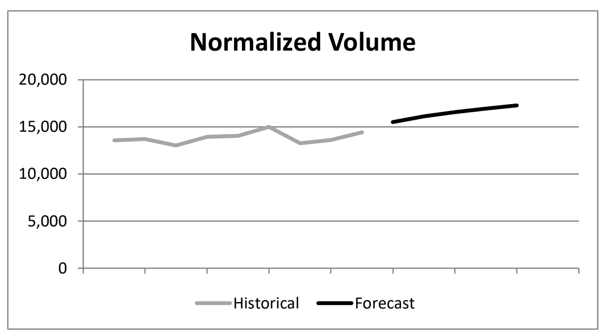
HIGH CASE

		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	15,731	6,816	6,949	6,603	6,978	X	X	0.0274	696.0	863.3
2014-2015	15,116	6,905	7,075	6,631	7,078	X	X	0.0278	737.2	906.9
2015-2016	14,956	5,990	6,812	6,238	6,793	X	X	0.0248	719.9	871.3
2016-2017	15,495	6,445	7,428	6,476	7,478	X	X	0.0199	779.2	900.6
2017-2018	15,359	6,869	7,312	6,780	7,282	X	X	0.0274	748.0	915.6
2018-2019	14,624	7,320	7,574	7,342	7,672	X	X	0.0338	820.0	1026.7
2019-2020	14,917	6,821	6,251	7,174	6,078	X	X	0.0496	585.3	888.4
2020-2021	14,460	6,327	7,083	6,396	7,210	X	X	0.0232	799.1	941.0
2021-2022	14,728	6,702	7,663	6,759	7,663	X	X	0.0235	835.3	979.2

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	14,732	X	X	7,328	8,181	7,638	8,264	0.0271	887.2	1052.7
2023-2024	14,699	X	X	7,608	8,504	7,928	8,590	0.0280	924.7	1096.1
2024-2025	14,646	X	X	7,811	8,750	8,137	8,838	0.0287	955.7	1130.8
2025-2026	14,578	X	X	7,993	8,964	8,325	9,054	0.0293	984.0	1163.2
2026-2027	14,512	X	X	8,138	9,131	8,475	9,222	0.0299	1007.0	1190.0

X : Not required





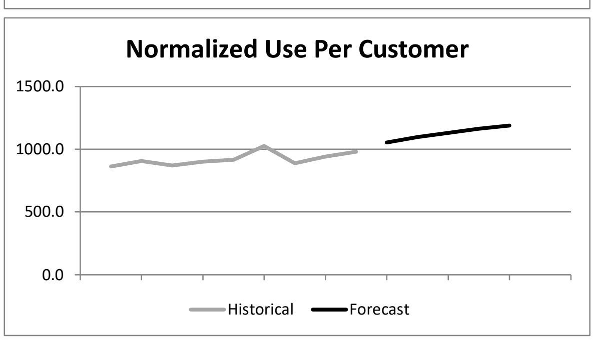


TABLE G-3 (C)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
G7, G17, COMPANY USE, OTHER CUSTOMER CHOICE

HIGH CASE

		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	29	311	418	*309*	*418*	X	X	0.1262	24102.8	*24873.8*
2014-2015	17	711	785	*688*	*786*	X	X	1.9905	73273.8	*85439.9*
2015-2016	16	733	969	*743*	*968*	X	X	0.9408	99544.5	*105294.9*
2016-2017	17	1,067	1,035	*1,075*	*1,049*	X	X	4.9398	91753.8	*121945.9*
2017-2018	17	972	1,081	*961*	*1,077*	X	X	3.0204	100835.1	*119296.0*
2018-2019	17	985	1,027	*988*	*1,040*	X	X	3.8326	95869.0	*119294.0*
2019-2020	17	998	1,008	*1,040*	*988*	X	X	5.1710	87668.7	*119274.2*
2020-2021	17	967	1,061	*978*	*1,082*	X	X	3.2774	102336.0	*122367.7*
2021-2022	16	1,010	966	*1,025*	*966*	X	X	5.5026	90750.7	*124382.4*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2023-2024	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2024-2025	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2025-2026	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2026-2027	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*

X : Not required

TABLE G-4 (A)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
INTERRUPTIBLE

HIGH CASE

		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2014-2015	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2015-2016	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2016-2017	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2017-2018	0	0	0	0	0	X	X	0.0000	0.0	0.0
2018-2019	0	0	0	0	0	X	X	0.0000	0.0	0.0
2019-2020	0	0	0	0	0	X	X	0.0000	0.0	0.0
2020-2021	0	0	0	0	0	X	X	0.0000	0.0	0.0
2021-2022	0	0	0	0	0	X	X	0.0000	0.0	0.0

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	0	X	X	0	0	0	0	0.0000	0.0	0.0
2023-2024	0	X	X	0	0	0	0	0.0000	0.0	0.0
2024-2025	0	X	X	0	0	0	0	0.0000	0.0	0.0
2025-2026	0	X	X	0	0	0	0	0.0000	0.0	0.0
2026-2027	0	X	X	0	0	0	0	0.0000	0.0	0.0

X : Not required

TABLE G-4 (B)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
SALES FOR RESALE, FIRM

HIGH CASE

	Average No. of Customers	Historical Retail Sendout (MDth) ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2014-2015	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2015-2016	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2016-2017	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2017-2018	0	0	0	0	0	X	X	0.0000	0.0	0.0
2018-2019	0	0	0	0	0	X	X	0.0000	0.0	0.0
2019-2020	0	0	0	0	0	X	X	0.0000	0.0	0.0
2020-2021	0	0	0	0	0	X	X	0.0000	0.0	0.0
2021-2022	0	0	0	0	0	X	X	0.0000	0.0	0.0

	Average No. of Customers	Forecast Retail Sendout (MDth) Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	0	X	X	0	0	0	0	0.0000	0.0	0.0
2023-2024	0	X	X	0	0	0	0	0.0000	0.0	0.0
2024-2025	0	X	X	0	0	0	0	0.0000	0.0	0.0
2025-2026	0	X	X	0	0	0	0	0.0000	0.0	0.0
2026-2027	0	X	X	0	0	0	0	0.0000	0.0	0.0

X : Not required

TABLE G-4 (C)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
UNACCOUNTED FOR

HIGH CASE

		Historical (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	X	11,778	-4,866	X	X	X	X	X	X	X
2014-2015	X	12,689	-6,615	X	X	X	X	X	X	X
2015-2016	X	6,124	-3,613	X	X	X	X	X	X	X
2016-2017	X	11,038	-8,444	X	X	X	X	X	X	X
2017-2018	X	11,947	-4,763	X	X	X	X	X	X	X
2018-2019	X	7,199	-5,106	X	X	X	X	X	X	X
2019-2020	X	7,610	-2,937	X	X	X	X	X	X	X
2020-2021		6,013	-3,937	X	X	X	X	X	X	X
2021-2022		8,616	447	8,980	447	X	X	X	X	X

		Forecast (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	X	X	X	9,126	611	12,702	1,258	X	X	X
2023-2024	X	X	X	9,407	466	13,044	1,073	X	X	X
2024-2025	X	X	X	9,879	600	13,508	1,127	X	X	X
2025-2026	X	X	X	9,887	675	13,524	1,198	X	X	X
2026-2027	X	X	X	9,942	834	13,585	1,351	X	X	X

X : Not required

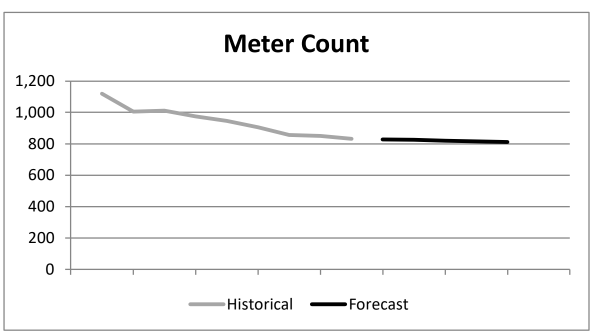
SENDOUT BY RATE CLASS
CAPACITY-EXEMPT VOLUMES (EXCLUDING POWERPLANTS)

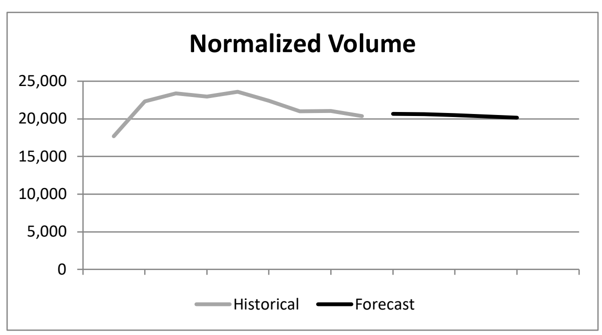
HIGH CASE

	Average No. of Customers	Historical Retail Sendout (MDth) ACTUAL Heating Season	Non-heating Season	NORMAL Heating Season	Non-heating Season	DESIGN Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	1,120	9,973	8,114	*9,499*	*8,179*	X	X	0.8534	10566.5	*15782.2*
2014-2015	1,006	10,993	11,716	*10,603*	*11,719*	X	X	0.5949	18556.5	*22192.5*
2015-2016	1,011	10,876	12,062	*11,372*	*12,024*	X	X	0.7326	18671.0	*23148.5*
2016-2017	976	11,489	11,219	*11,582*	*11,367*	X	X	0.9359	17797.9	*23518.1*
2017-2018	946	11,875	11,936	*11,696*	*11,876*	X	X	0.8987	19418.2	*24910.9*
2018-2019	907	11,300	10,880	*11,340*	*11,060*	X	X	1.0002	18592.9	*24706.0*
2019-2020	856	10,819	9,922	*11,378*	*9,647*	X	X	1.3690	16192.5	*24559.6*
2020-2021	850	10,646	9,838	*10,837*	*10,192*	X	X	1.0995	18016.0	*24735.9*
2021-2022	832	10,269	9,948	*10,412*	*9,948*	X	X	1.0450	18071.0	*24458.3*

	Average No. of Customers	Forecast Retail Sendout (MDth) Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	829	X	X	10,625	10,014	11,334	10,205	1.1009	18172.8	*24901.3*
2023-2024	826	X	X	10,604	10,000	11,311	10,190	1.1010	18207.2	*24936.6*
2024-2025	821	X	X	10,535	9,951	11,235	10,139	1.0975	18249.2	*24957.2*
2025-2026	816	X	X	10,446	9,886	11,137	10,072	1.0903	18248.1	*24911.8*
2026-2027	812	X	X	10,343	9,805	11,026	9,988	1.0823	18213.1	*24828.2*

X : Not required





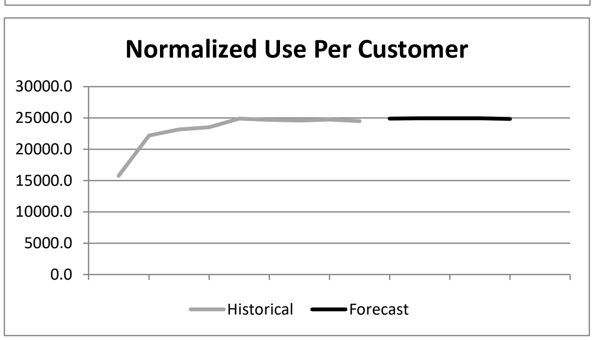


TABLE G-5 (A)

Company: National Grid
Filing Date: November 1, 2022

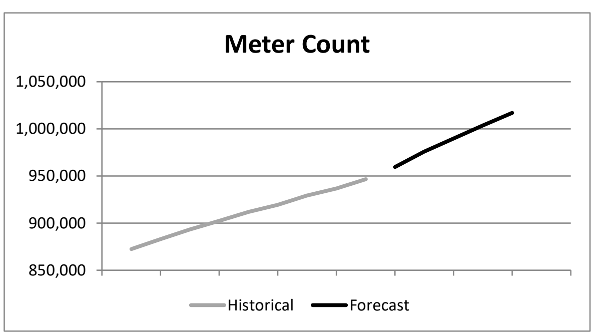
SENDOUT BY RATE CLASS
TOTAL RETAIL VOLUMES (EXCLUDING POWERPLANTS)

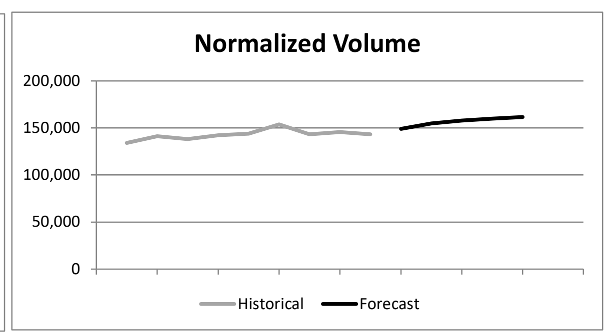
HIGH CASE

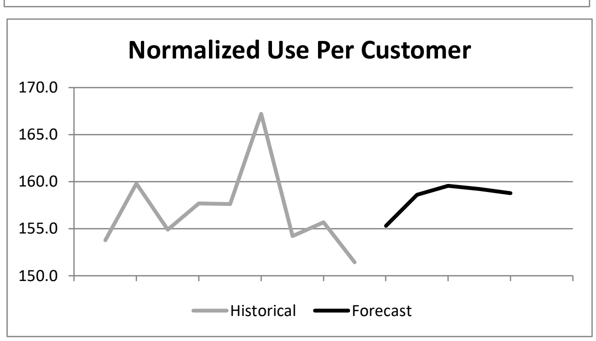
		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	872,411	92,367	47,469	*85,796*	*48,370*	X	X	0.0152	61.0	*153.8*
2014-2015	882,951	97,523	52,178	*88,824*	*52,258*	X	X	0.0151	67.6	*159.8*
2015-2016	893,142	79,208	50,719	*88,301*	*50,026*	X	X	0.0152	61.9	*154.9*
2016-2017	902,399	85,610	53,469	*86,859*	*55,451*	X	X	0.0136	74.8	*157.7*
2017-2018	911,914	92,930	54,590	*90,103*	*53,639*	X	X	0.0147	67.8	*157.6*
2018-2019	919,442	97,493	52,584	*98,158*	*55,576*	X	X	0.0164	66.7	*167.2*
2019-2020	929,286	88,865	50,478	*96,662*	*46,653*	X	X	0.0176	46.7	*154.2*
2020-2021	936,773	89,628	47,995	*92,513*	*53,329*	X	X	0.0150	63.9	*155.7*
2021-2022	946,448	89,563	51,404	*91,902*	*51,404*	X	X	0.0151	59.3	*151.4*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	959,680	X	X	95,691	53,366	107,253	56,477	0.0155	60.5	*155.3*
2023-2024	975,669	X	X	99,648	55,093	111,757	58,350	0.0160	61.0	*158.6*
2024-2025	989,877	X	X	102,323	55,616	114,891	58,997	0.0163	59.7	*159.6*
2025-2026	1,003,677	X	X	103,627	56,181	116,375	59,610	0.0163	59.3	*159.2*
2026-2027	1,016,984	X	X	104,833	56,647	117,756	60,123	0.0164	58.8	*158.8*

X : Not required







Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
TOTAL WHOLESALE VOLUMES (EXCLUDING POWERPLANTS)

HIGH CASE

		Historical Wholesale Sendout (MDth)									
		ACTUAL		NORMAL		DESIGN					
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)	Actual Peak Day (MMBtu)
2013-2014	872,411	104,145	42,603	*95,876*	*43,737*	X	X	0.0191	43.2	*160.0*	1,225,493
2014-2015	882,951	110,212	45,563	*99,026*	*45,666*	X	X	0.0194	45.3	*163.9*	1,211,969
2015-2016	893,142	85,332	47,107	*96,241*	*46,275*	X	X	0.0183	48.0	*159.6*	1,287,533
2016-2017	902,399	96,648	45,024	*98,340*	*47,711*	X	X	0.0184	49.5	*161.8*	1,115,301
2017-2018	911,914	104,877	49,827	*101,254*	*48,608*	X	X	0.0188	49.3	*164.3*	1,356,014
2018-2019	919,442	104,691	47,478	*105,475*	*51,006*	X	X	0.0194	51.7	*170.2*	1,342,428
2019-2020	929,286	96,475	47,541	*105,689*	*43,021*	X	X	0.0208	33.0	*160.0*	1,091,737
2020-2021	936,773	95,640	44,058	*98,980*	*50,232*	X	X	0.0174	53.0	*159.3*	1,177,839
2021-2022	946,448	98,178	51,851	*100,882*	*51,851*	X	X	0.0174	54.9	*161.4*	1,225,003

		Forecast Wholesale Sendout (MDth)									
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)	Design Day (MMBtu)
2022-2023	959,680	X	X	104,817	53,978	119,956	57,735	0.0178	56.5	*165.5*	1,588,379
2023-2024	975,669	X	X	109,055	55,559	124,802	59,423	0.0184	56.5	*168.7*	1,652,937
2024-2025	989,877	X	X	112,202	56,216	128,399	60,124	0.0188	55.3	*170.1*	1,701,408
2025-2026	1,003,677	X	X	113,514	56,856	129,899	60,808	0.0188	55.1	*169.7*	1,722,445
2026-2027	1,016,984	X	X	114,774	57,481	131,341	61,474	0.0187	55.0	*169.4*	1,742,672

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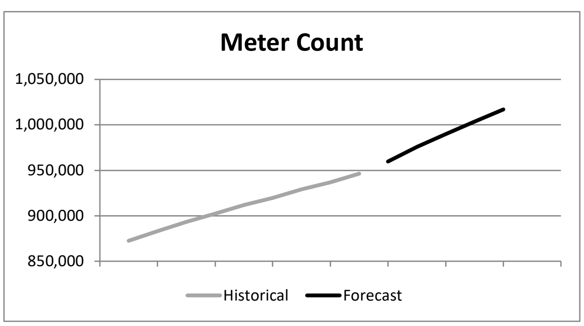
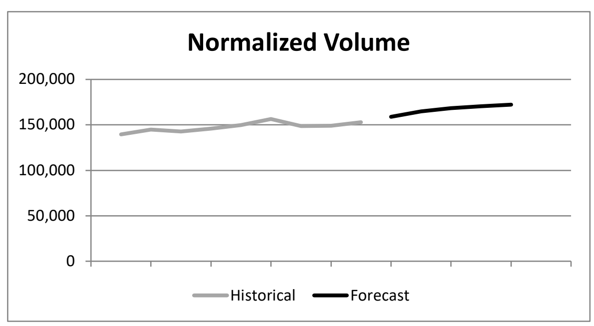




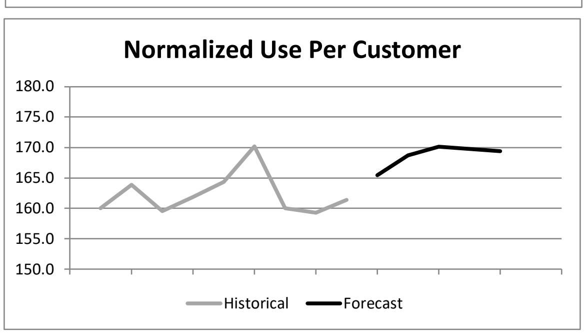


TABLE G-1

Company: National Grid
Filing Date: November 1, 2022

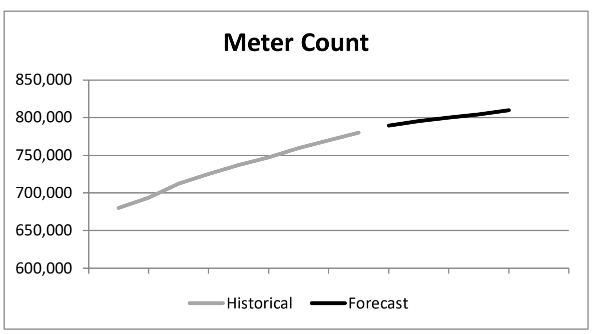
SENDOUT BY RATE CLASS
RESIDENTIAL HEATING

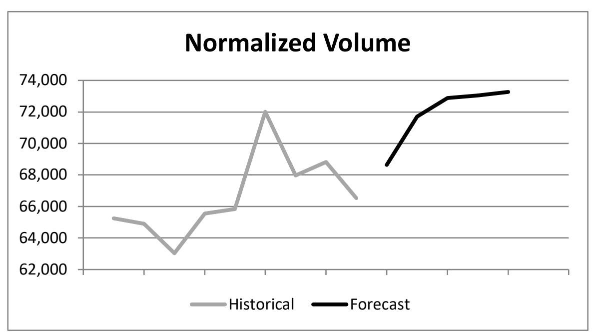
LOW CASE

		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	680,154	48,261	20,263	*44,471*	*20,783*	X	X	0.0112	27.3	*95.9*
2014-2015	693,459	49,662	20,260	*44,594*	*20,307*	X	X	0.0112	25.2	*93.6*
2015-2016	712,632	38,843	19,300	*44,125*	*18,897*	X	X	0.0111	20.7	*88.4*
2016-2017	725,173	42,407	21,299	*43,120*	*22,433*	X	X	0.0097	31.4	*90.4*
2017-2018	737,184	46,609	21,411	*44,972*	*20,861*	X	X	0.0105	25.0	*89.3*
2018-2019	747,139	49,374	20,521	*49,758*	*22,251*	X	X	0.0117	24.9	*96.4*
2019-2020	759,736	44,407	21,359	*48,703*	*19,252*	X	X	0.0119	17.0	*89.4*
2020-2021	769,959	45,333	18,746	*46,994*	*21,817*	X	X	0.0105	25.0	*89.4*
2021-2022	780,058	44,824	20,370	*46,161*	*20,370*	X	X	0.0104	21.4	*85.3*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	789,389	X	X	47,496	21,136	53,987	22,882	0.0106	22.3	*86.9*
2023-2024	795,667	X	X	49,740	21,972	56,561	23,807	0.0110	22.7	*90.1*
2024-2025	800,235	X	X	51,047	21,832	58,148	23,742	0.0114	21.3	*91.1*
2025-2026	804,609	X	X	51,217	21,828	58,352	23,748	0.0114	21.0	*90.8*
2026-2027	810,011	X	X	51,431	21,843	58,608	23,774	0.0114	20.8	*90.5*

X : Not required





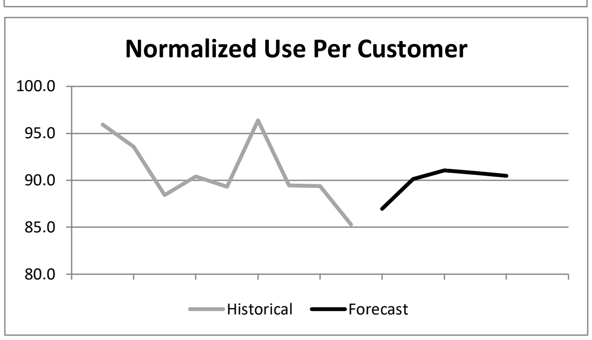


TABLE G-2

Company: National Grid
Filing Date: November 1, 2022

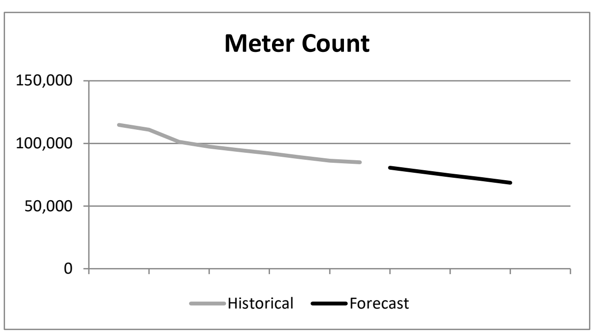
SENDOUT BY RATE CLASS
RESIDENTIAL NON-HEATING

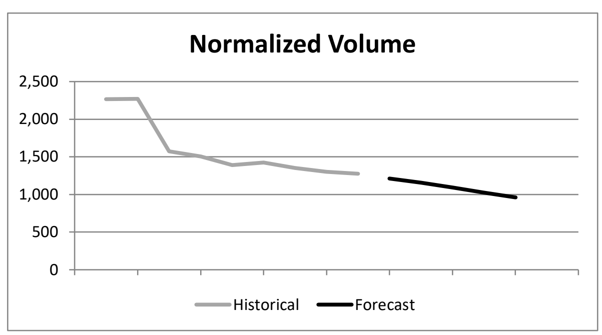
LOW CASE

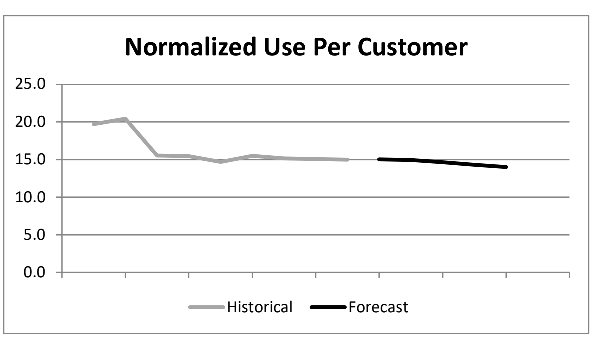
		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	114,938	1,309	1,016	*1,243*	*1,025*	X	X	0.0012	12.7	*19.7*
2014-2015	111,170	1,379	989	*1,281*	*990*	X	X	0.0013	12.2	*20.4*
2015-2016	101,282	781	741	*835*	*737*	X	X	0.0008	10.6	*15.5*
2016-2017	97,495	763	724	*769*	*735*	X	X	0.0007	11.4	*15.4*
2017-2018	94,713	731	678	*717*	*673*	X	X	0.0007	10.7	*14.7*
2018-2019	92,112	754	656	*757*	*671*	X	X	0.0008	10.7	*15.5*
2019-2020	89,130	680	657	*711*	*641*	X	X	0.0007	10.6	*15.2*
2020-2021	86,185	679	583	*692*	*608*	X	X	0.0008	10.3	*15.1*
2021-2022	85,020	684	580	*696*	*580*	X	X	0.0009	9.7	*15.0*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	80,651	X	X	661	551	715	565	0.0009	9.7	*15.0*
2023-2024	77,554	X	X	636	522	690	537	0.0009	9.5	*14.9*
2024-2025	74,589	X	X	601	490	652	504	0.0009	9.3	*14.6*
2025-2026	71,624	X	X	566	459	614	472	0.0009	9.0	*14.3*
2026-2027	68,659	X	X	532	429	578	442	0.0009	8.8	*14.0*

X : Not required







SENDOUT BY RATE CLASS
COMMERCIAL, FIRM

LOW CASE

Historical Retail Sendout (MDth)

	Average No. of Customers	ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	60,439	25,696	10,709	*23,672*	*10,987*	X	X	0.0675	160.6	*573.4*
2014-2015	62,183	27,873	11,352	*25,027*	*11,379*	X	X	0.0701	157.0	*585.5*
2015-2016	63,245	21,985	10,835	*24,987*	*10,607*	X	X	0.0710	129.1	*562.8*
2016-2017	63,243	23,440	11,764	*23,835*	*12,391*	X	X	0.0612	198.8	*572.8*
2017-2018	63,696	25,874	12,173	*24,976*	*11,870*	X	X	0.0668	170.0	*578.5*
2018-2019	64,643	27,759	11,924	*27,972*	*12,883*	X	X	0.0749	174.2	*632.0*
2019-2020	64,630	25,141	11,280	*27,657*	*10,046*	X	X	0.0816	84.6	*583.4*
2020-2021	65,302	25,676	10,684	*26,615*	*12,419*	X	X	0.0701	169.3	*597.7*
2021-2022	64,726	25,895	11,564	*26,674*	*11,564*	X	X	0.0733	142.5	*590.8*

Forecast Retail Sendout (MDth)

	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	64,277	X	X	26,205	11,351	29,830	12,326	0.0726	140.6	*584.3*
2023-2024	64,515	X	X	26,244	11,432	29,866	12,407	0.0722	142.4	*584.0*
2024-2025	64,951	X	X	26,744	11,668	30,432	12,660	0.0731	144.7	*591.4*
2025-2026	65,344	X	X	27,237	11,865	30,996	12,876	0.0740	145.9	*598.4*
2026-2027	65,645	X	X	27,619	12,020	31,432	13,045	0.0748	146.9	*603.8*

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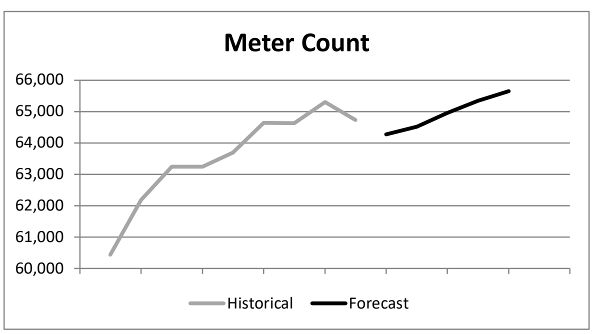
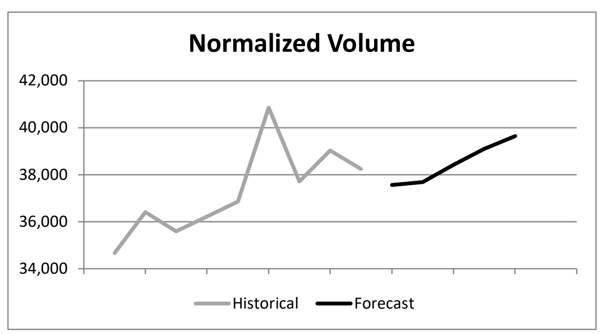
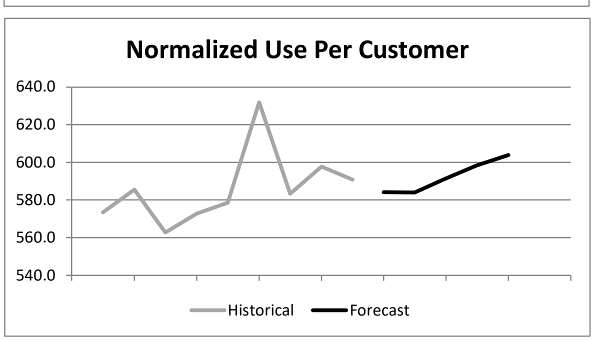






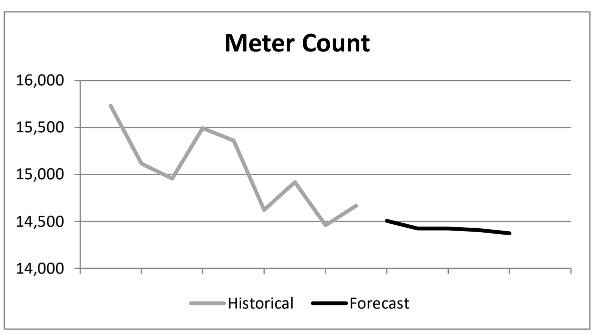
SENDOUT BY RATE CLASS
INDUSTRIAL, FIRM

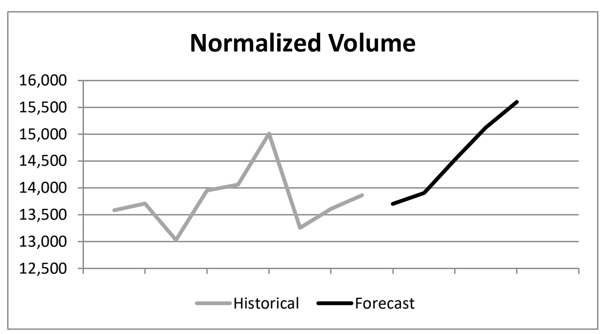
LOW CASE

		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	15,731	6,816	6,949	*6,603*	*6,978*	X	X	0.0274	696.0	*863.3*
2014-2015	15,116	6,905	7,075	*6,631*	*7,078*	X	X	0.0278	737.2	*906.9*
2015-2016	14,956	5,990	6,812	*6,238*	*6,793*	X	X	0.0248	719.9	*871.3*
2016-2017	15,495	6,445	7,428	*6,476*	*7,478*	X	X	0.0199	779.2	*900.6*
2017-2018	15,359	6,869	7,312	*6,780*	*7,282*	X	X	0.0274	748.0	*915.6*
2018-2019	14,624	7,320	7,574	*7,342*	*7,672*	X	X	0.0338	820.0	*1026.7*
2019-2020	14,917	6,821	6,251	*7,174*	*6,078*	X	X	0.0496	585.3	*888.4*
2020-2021	14,460	6,327	7,083	*6,396*	*7,210*	X	X	0.0232	799.1	*941.0*
2021-2022	14,668	6,665	7,129	*6,736*	*7,129*	X	X	0.0298	763.0	*945.3*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2021-2022	14,507	X	X	6,657	7,045	6,993	7,135	0.0298	762.3	*944.5*
2022-2023	14,423	X	X	6,693	7,215	7,012	7,301	0.0285	790.2	*964.3*
2023-2024	14,423	X	X	6,923	7,604	7,233	7,687	0.0277	837.9	*1007.2*
2024-2025	14,409	X	X	7,204	7,918	7,527	8,004	0.0288	873.5	*1049.5*
2025-2026	14,375	X	X	7,423	8,177	7,752	8,266	0.0295	905.0	*1085.3*

X : Not required





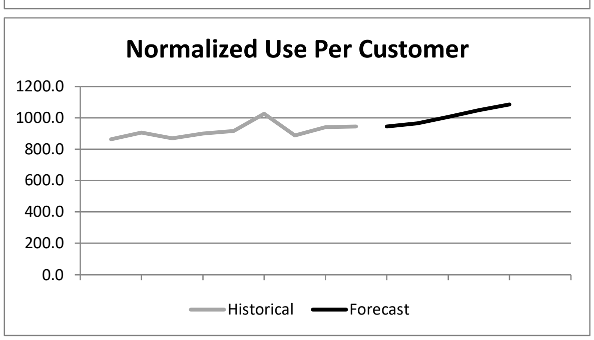


TABLE G-3 (C)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
G7, G17, COMPANY USE, OTHER CUSTOMER CHOICE

LOW CASE

		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	29	311	418	*309*	*418*	X	X	0.1262	24102.8	*24873.8*
2014-2015	17	711	785	*688*	*786*	X	X	1.9905	73273.8	*85439.9*
2015-2016	16	733	969	*743*	*968*	X	X	0.9408	99544.5	*105294.9*
2016-2017	17	1,067	1,035	*1,075*	*1,049*	X	X	4.9398	91753.8	*121945.9*
2017-2018	17	972	1,081	*961*	*1,077*	X	X	3.0204	100835.1	*119296.0*
2018-2019	17	985	1,027	*988*	*1,040*	X	X	3.8326	95869.0	*119294.0*
2019-2020	17	998	1,008	*1,040*	*988*	X	X	5.1710	87668.7	*119274.2*
2020-2021	17	967	1,061	*978*	*1,082*	X	X	3.2774	102336.0	*122367.7*
2021-2022	16	1,010	966	*1,025*	*966*	X	X	5.5026	90750.7	*124382.4*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2023-2024	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2024-2025	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2025-2026	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*
2026-2027	16	X	X	963	966	1,019	981	4.5139	92937.8	*120526.8*

X : Not required

TABLE G-4 (A)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
INTERRUPTIBLE

LOW CASE

	Average No. of Customers	Historical Retail Sendout (MDth) ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2014-2015	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2015-2016	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2016-2017	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2017-2018	0	0	0	0	0	X	X	0.0000	0.0	0.0
2018-2019	0	0	0	0	0	X	X	0.0000	0.0	0.0
2019-2020	0	0	0	0	0	X	X	0.0000	0.0	0.0
2020-2021	0	0	0	0	0	X	X	0.0000	0.0	0.0
2021-2022	0	0	0	0	0	X	X	0.0000	0.0	0.0

	Average No. of Customers	Forecast Retail Sendout (MDth) Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	0	X	X	0	0	0	0	0.0000	0.0	0.0
2023-2024	0	X	X	0	0	0	0	0.0000	0.0	0.0
2024-2025	0	X	X	0	0	0	0	0.0000	0.0	0.0
2025-2026	0	X	X	0	0	0	0	0.0000	0.0	0.0
2026-2027	0	X	X	0	0	0	0	0.0000	0.0	0.0

X : Not required

TABLE G-4 (B)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
SALES FOR RESALE, FIRM

LOW CASE

	Average No. of Customers	Historical Retail Sendout (MDth) ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2014-2015	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2015-2016	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2016-2017	0	0	0	*0*	*0*	X	X	0.0000	0.0	0.0
2017-2018	0	0	0	0	0	X	X	0.0000	0.0	0.0
2018-2019	0	0	0	0	0	X	X	0.0000	0.0	0.0
2019-2020	0	0	0	0	0	X	X	0.0000	0.0	0.0
2020-2021	0	0	0	0	0	X	X	0.0000	0.0	0.0
2021-2022	0	0	0	0	0	X	X	0.0000	0.0	0.0

	Average No. of Customers	Forecast Retail Sendout (MDth) Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	0	X	X	0	0	0	0	0.0000	0.0	0.0
2023-2024	0	X	X	0	0	0	0	0.0000	0.0	0.0
2024-2025	0	X	X	0	0	0	0	0.0000	0.0	0.0
2025-2026	0	X	X	0	0	0	0	0.0000	0.0	0.0
2026-2027	0	X	X	0	0	0	0	0.0000	0.0	0.0

X : Not required

TABLE G-4 (C)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
UNACCOUNTED FOR

LOW CASE

Historical (MDth)

		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	X	11,778	-4,866	X	X	X	X	X	X	X
2014-2015	X	12,689	-6,615	X	X	X	X	X	X	X
2015-2016	X	6,124	-3,613	X	X	X	X	X	X	X
2016-2017	X	11,038	-8,444	X	X	X	X	X	X	X
2017-2018	X	11,947	-4,763	X	X	X	X	X	X	X
2018-2019	X	7,199	-5,106	X	X	X	X	X	X	X
2019-2020	X	7,610	-2,937	X	X	X	X	X	X	X
2020-2021	X	6,013	-3,937	X	X	X	X	X	X	X
2021-2022	X	8,857	-108	9,249	-108	X	X	X	X	X

Forecast (MDth)

	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	X	X	X	9,364	508	12,777	1,038	X	X	X
2023-2024	X	X	X	8,944	576	12,315	1,101	X	X	X
2024-2025	X	X	X	9,094	590	12,444	1,060	X	X	X
2025-2026	X	X	X	10,611	1,334	12,561	1,025	X	X	X
2026-2027	X	X	X	9,303	612	12,710	1,084	X	X	X

X : Not required

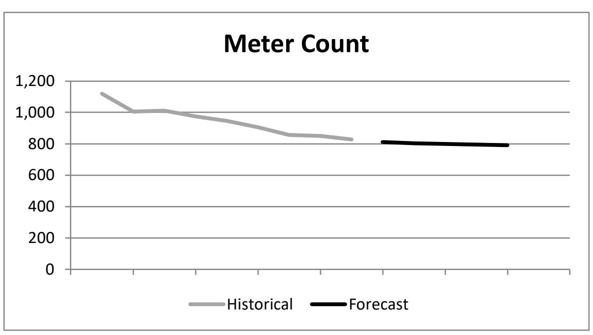
SENDOUT BY RATE CLASS
CAPACITY-EXEMPT VOLUMES (EXCLUDING POWERPLANTS)

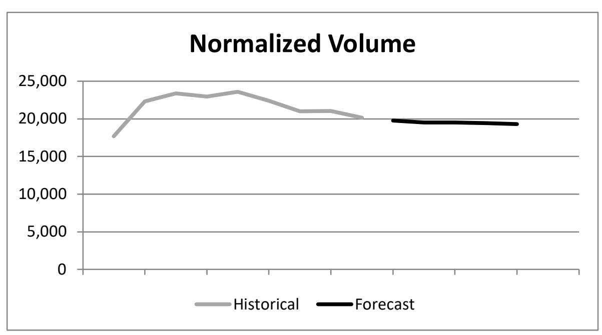
LOW CASE

		Historical Retail Sendout (MDth)								
		ACTUAL		NORMAL		DESIGN				
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	1,120	9,973	8,114	*9,499*	*8,179*	X	X	0.8534	10566.5	*15782.2*
2014-2015	1,006	10,993	11,716	*10,603*	*11,719*	X	X	0.5949	18556.5	*22192.5*
2015-2016	1,011	10,876	12,062	*11,372*	*12,024*	X	X	0.7326	18671.0	*23148.5*
2016-2017	976	11,489	11,219	*11,582*	*11,367*	X	X	0.9359	17797.9	*23518.1*
2017-2018	946	11,875	11,936	*11,696*	*11,876*	X	X	0.8987	19418.2	*24910.9*
2018-2019	907	11,300	10,880	*11,340*	*11,060*	X	X	1.0002	18592.9	*24706.0*
2019-2020	856	10,819	9,922	*11,378*	*9,647*	X	X	1.3690	16192.5	*24559.6*
2020-2021	850	10,646	9,838	*10,837*	*10,192*	X	X	1.0995	18016.0	*24735.9*
2021-2022	829	10,244	9,730	*10,392*	*9,730*	X	X	1.0915	17613.4	*24284.8*

		Forecast Retail Sendout (MDth)								
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	812	X	X	10,228	9,536	10,926	9,724	1.1050	17583.9	*24338.0*
2023-2024	805	X	X	10,067	9,458	10,744	9,640	1.0811	17650.3	*24258.1*
2024-2025	799	X	X	10,009	9,470	10,672	9,648	1.0677	17851.0	*24376.8*
2025-2026	796	X	X	9,970	9,452	10,628	9,628	1.0634	17897.5	*24397.0*
2026-2027	792	X	X	9,901	9,411	10,551	9,585	1.0557	17928.5	*24381.0*

X : Not required





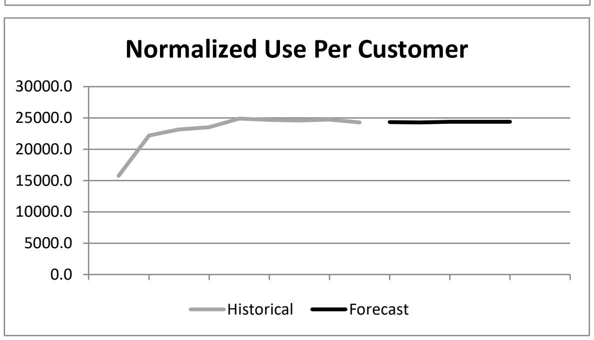


TABLE G-5 (A)

Company: National Grid
Filing Date: November 1, 2022

SENDOUT BY RATE CLASS
TOTAL RETAIL VOLUMES (EXCLUDING POWERPLANTS)

LOW CASE

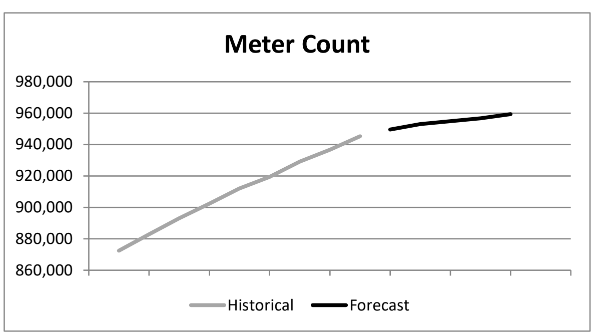
Historical Retail Sendout (MDth)

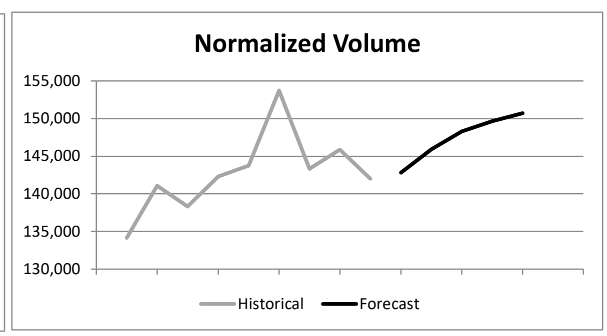
	Average No. of Customers	ACTUAL Heating Season	ACTUAL Non-heating Season	NORMAL Heating Season	NORMAL Non-heating Season	DESIGN Heating Season	DESIGN Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2013-2014	872,411	92,367	47,469	*85,796*	*48,370*	X	X	0.0152	61.0	*153.8*
2014-2015	882,951	97,523	52,178	*88,824*	*52,258*	X	X	0.0151	67.6	*159.8*
2015-2016	893,142	79,208	50,719	*88,301*	*50,026*	X	X	0.0152	61.9	*154.9*
2016-2017	902,399	85,610	53,469	*86,859*	*55,451*	X	X	0.0136	74.8	*157.7*
2017-2018	911,914	92,930	54,590	*90,103*	*53,639*	X	X	0.0147	67.8	*157.6*
2018-2019	919,442	97,493	52,584	*98,158*	*55,576*	X	X	0.0164	66.7	*167.2*
2019-2020	929,286	88,865	50,478	*96,662*	*46,653*	X	X	0.0176	46.7	*154.2*
2020-2021	936,773	89,628	47,995	*92,513*	*53,329*	X	X	0.0150	63.9	*155.7*
2021-2022	945,317	89,322	50,338	*91,684*	*50,338*	X	X	0.0152	57.1	*150.2*

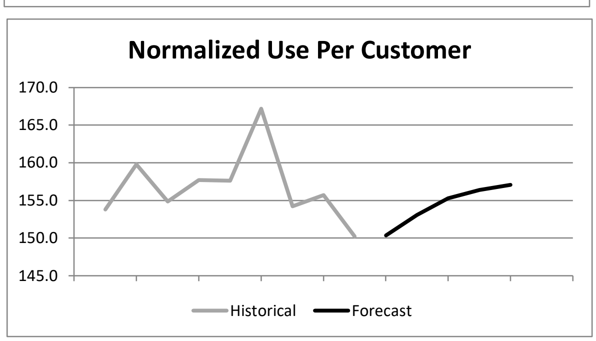
Forecast Retail Sendout (MDth)

	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)
2022-2023	949,652	X	X	92,209	50,584	103,470	53,613	0.0153	57.1	*150.4*
2023-2024	952,980	X	X	94,344	51,565	105,891	54,671	0.0156	57.8	*153.1*
2024-2025	955,013	X	X	96,287	52,029	108,156	55,222	0.0160	57.5	*155.3*
2025-2026	956,798	X	X	97,158	52,487	109,136	55,710	0.0161	57.9	*156.4*
2026-2027	959,498	X	X	97,870	52,846	109,940	56,093	0.0162	58.1	*157.1*

X : Not required







SENDOUT BY RATE CLASS
TOTAL WHOLESALE VOLUMES (EXCLUDING POWERPLANTS)

LOW CASE

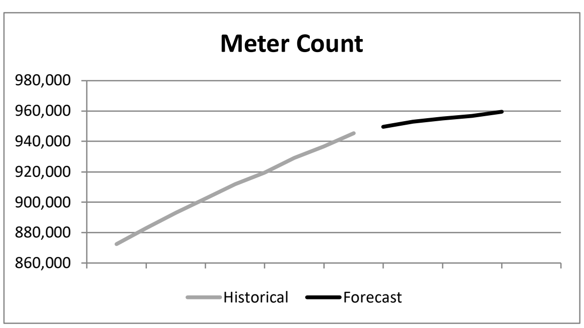
Historical Wholesale Sendout (MDth)

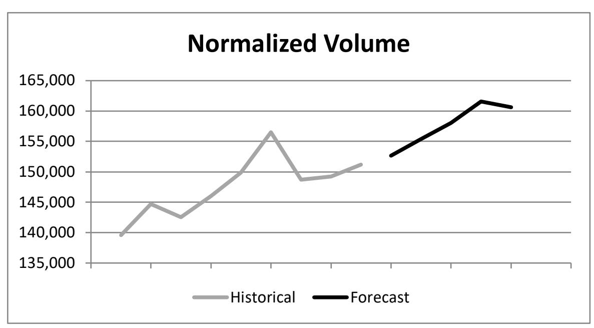
		ACTUAL		NORMAL		DESIGN					
	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)	Actual Peak Day (MMBtu)
2013-2014	872,411	104,145	42,603	*95,876*	*43,737*	X	X	0.0191	43.2	*160.0*	1,225,493
2014-2015	882,951	110,212	45,563	*99,026*	*45,666*	X	X	0.0194	45.3	*163.9*	1,211,969
2015-2016	893,142	85,332	47,107	*96,241*	*46,275*	X	X	0.0183	48.0	*159.6*	1,287,533
2016-2017	902,399	96,648	45,024	*98,340*	*47,711*	X	X	0.0184	49.5	*161.8*	1,115,301
2017-2018	911,914	104,877	49,827	*101,254*	*48,608*	X	X	0.0188	49.3	*164.3*	1,356,014
2018-2019	919,442	104,691	47,478	*105,475*	*51,006*	X	X	0.0194	51.7	*170.2*	1,342,428
2019-2020	929,286	96,475	47,541	*105,689*	*43,021*	X	X	0.0208	33.0	*160.0*	1,091,737
2020-2021	936,773	95,640	44,058	*98,980*	*50,232*	X	X	0.0174	53.0	*159.3*	1,177,839
2021-2022	945,317	98,178	50,230	*100,932*	*50,230*	X	X	0.0178	51.3	*159.9*	1,225,003

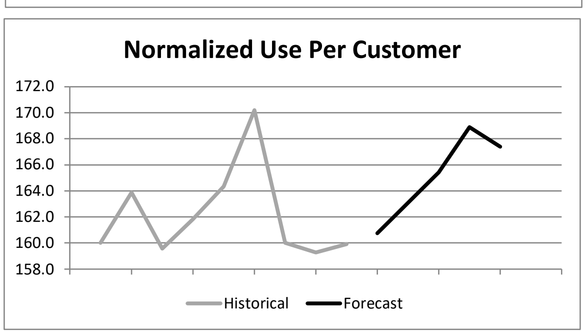
Forecast Wholesale Sendout (MDth)

	Average No. of Customers	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Heating Season	Non-heating Season	Planning Year Heating Use per Customer (MMBtu/EDD)	Planning Year Annual Baseload Use per Customer (MMBtu)	Normalized UPC (MMBtu/cust)	Design Day (MMBtu)
2022-2023	949,652	X	X	101,574	51,092	116,247	54,651	0.0177	52.6	*160.8*	1,539,465
2023-2024	952,980	X	X	103,288	52,141	118,206	55,772	0.0179	53.7	*163.1*	1,565,976
2024-2025	955,013	X	X	105,381	52,619	120,600	56,282	0.0183	53.4	*165.4*	1,598,593
2025-2026	956,798	X	X	107,769	53,821	121,697	56,735	0.0187	54.6	*168.9*	1,614,340
2026-2027	959,498	X	X	107,173	53,458	122,650	57,177	0.0186	54.0	*167.4*	1,628,133

X : Not required







Impact of Causative Variables on Use Factors

See Narrative at Section III

EXISTING GAS MANUFACTURING AND STORAGE FACILITIES (MMBTU)

Type of Facility	Location	Anticipated Retirement Date	11/21 - 3/22 Total Sendout (MMBtu) [1]	11/21 - 3/22 Max. 24 hr. Sendout (MMBtu) [1]	Maximum Daily Design Capacity (MMBtu) [2] [3]	Storage Capacity (MMBtu) [2]
LNG Storage	Dorchester	None				1,192,345
LNG Vaporization	Dorchester	None	346,972	84,789	198,968	
LNG Storage	Lynn	None				1,045,000
LNG Vaporization	Lynn	None	256,166	41,234	120,142	
LNG Storage	Salem	None				1,045,000
LNG Vaporization	Salem	None	238,482	23,247	31,768	
LNG Storage	Tewksbury	None				1,045,000
LNG Vaporization	Tewksbury	None	284,815	48,696	83,600	
LNG Storage	So. Yarmouth	None				179,740
LNG Vaporization	So. Yarmouth	None	51,342	5,720	27,600	
LNG Storage	Wareham	None				9,234
LNG Vaporization	Wareham	None	1,359	424	4,494	
LNG Storage	Haverhill	None				418,000
LNG Vaporization	Haverhill	None	149,844	25,684	41,069	

[1] Sendout numbers include boiloff and reflect 11/1/21 - 3/31/22 usage.
[2] BTU conversion factor for LNG = 1045.
[3] Tewksbury vaporization capacity expected to increase to 104,500 MMBtu per day for winter 2026/27.

Table G-15

National Grid
November 1, 2022

Participation in or Services from Manufacturing and Storage Facilities Planned Outside Massachusetts
(See Rule 67.5)

Anticipated Category	Location	Anticipated In-Service Date	Annual Sendout (Mcf)*	Peak Daily Sendout (Mcf)*	Storage Capacity (Mcf)*
LNG Liquefaction	Providence, RI	April 1, 2023	3,341,627	17,210	1,109,726

*Note: Assumes 1 Mcf = 1.045 MMBtu.

Table G-16

National Grid
November 1, 2022

Exempt and Approved Manufacturing and Storage Facilities In Massachusetts and Not Yet in Operation (See Rule 67.5)

Category	Location	Anticipated In-Service Date	Annual Sendout (Mcf)*	Peak Daily Sendout (Mcf)*	Storage Capacity (Mcf)*
LNG Liquefaction	Charlton, MA	April 1, 2023	2,506,220	11,713	58,565 (Apr – Oct) 35,139 (Nov – Mar)

*Note: Assumes 1 Mcf = 1.045 MMBtu

Table G-17

National Grid
November 1, 2022

Proposed Manufacturing and Storage Facilities in Massachusetts
(See Rule 67.5)

Category	Name of Facility	Location	Site Acreage	In-Service Date	Annual Sendout Capacity	Peak Daily Sendout (Mcf)	Storage Capacity
None							

Table G-21

National Grid
November 1, 2022

Proposed Pipelines in Massachusetts
Over 1 Mile in Length and Over 100 PSI

Name or Numerical Designation	Origin	Terminus	Length	Diameter	Maximum Allowable Operating Pressure (MAOP)	In Service Date
Tewksbury Line Replacement (a.k.a. Lowell Area Gas Modernization Project (LAGMP)	Canal St @ Riverneck Rd, Chelmsford	Wilbur Street Gas Regulation Station, Lowell	2.4 miles	12”	610 psig	6/30/2023

Current Method - BASE CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Normal Year
(BBtu)

			HEATING SEASON (NOV-MAR)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	68,415	72,197	74,308	75,406	76,475
		Essex	5,368	5,468	5,488	5,544	5,598
		Lowell	9,903	10,079	10,072	10,123	10,172
		Cape	8,416	8,603	8,645	8,737	8,824
2	Fuel Reimbursement		2,061	2,210	2,278	2,297	2,329
3	Underground Storage Refill		0	0	0	0	0
4	LNG Storage Refill		274	0	0	0	0
5	TOTAL		94,436	98,557	100,792	102,106	103,397
	RESOURCES						
6	TGP	Dracut	0	0	0	0	0
7		Dawn/Niagara	3,312	5,758	6,235	6,168	6,298
8		Waddington	0	24	112	2,543	2,555
9		Gulf	0	0	0	0	0
10		Market Area	35,587	37,056	37,607	36,280	36,668
11		Storage	8,248	8,218	8,145	8,140	8,145
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	22,682	23,739	23,958	24,368	25,226
14		Storage	10,568	10,589	10,568	10,319	10,319
15		AIM (Millennium)	7,595	7,645	7,595	7,595	6,930
16		AIM (Ramapo)	236	442	1,261	1,172	1,625
17		Atlantic Bridge	69	73	295	491	583
18		Beverly	300	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		5,564	5,012	5,017	5,030	5,049
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		94,436	98,557	100,792	102,106	103,397

Current Method - BASE CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Normal Year
(BBtu)

			NON-HEATING SEASON (APR-OCT)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	32,060	33,325	33,867	34,417	34,951
		Essex	2,326	2,350	2,373	2,396	2,418
		Lowell	4,066	4,094	4,115	4,136	4,157
		Cape	4,083	4,133	4,177	4,219	4,262
2	Fuel Reimbursement		1,732	1,690	1,615	1,552	1,637
3	Underground Storage Refill		18,877	18,822	18,713	18,459	18,463
4	LNG Storage Refill		6,108	5,829	5,834	5,848	5,867
5	TOTAL		69,252	70,242	70,695	71,028	71,755
	RESOURCES						
6	TGP	Dracut	1	0	0	1,770	1,260
7		Dawn/Niagara	355	607	368	486	373
8		Waddington	12	12	13	14	15
9		Gulf	0	0	0	0	0
10		Market Area	29,982	30,601	31,067	29,045	29,938
11		Storage	0	0	0	0	0
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	27,232	29,442	34,229	37,817	36,647
14		Storage	61	15	0	0	0
15		AIM (Millennium)	10,763	8,444	3,803	707	2,291
16		AIM (Ramapo)	29	303	397	366	404
17		Atlantic Bridge	0	0	1	5	9
18		Beverly	0	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		0	0	0	0	0
21	LNG Withdrawal Storage		818	818	818	818	818
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		69,252	70,242	70,695	71,028	71,755

Current Method - BASE CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

			HEATING SEASON (NOV-MAR)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	78,201	82,529	84,938	86,193	87,415
		Essex	6,194	6,310	6,333	6,398	6,460
		Lowell	11,394	11,597	11,589	11,648	11,703
		Cape	9,643	9,858	9,906	10,011	10,110
2	Fuel Reimbursement		2,434	2,541	2,585	2,587	2,609
3	Underground Storage Refill		0	0	0	0	0
4	LNG Storage Refill		274	0	0	0	0
5	TOTAL		108,141	112,835	115,352	116,836	118,297
	RESOURCES						
6	TGP	Dracut	1	1	12	12	4
7		Dawn/Niagara	7,677	8,094	8,220	7,876	7,827
8		Waddington	1,089	986	1,135	3,635	3,649
9		Gulf	0	0	0	0	0
10		Market Area	39,023	40,181	40,339	39,354	39,678
11		Storage	8,189	8,135	8,139	8,139	8,140
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	24,700	26,096	26,445	26,588	27,188
14		Storage	10,568	10,589	10,568	10,319	10,319
15		AIM (Millennium)	7,595	7,645	7,595	7,595	7,245
16		AIM (Ramapo)	2,412	2,819	3,120	2,908	3,069
17		Atlantic Bridge	749	1,125	1,237	1,233	1,362
18		Beverly	300	1,333	2,875	2,972	3,165
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		5,564	5,290	5,290	5,290	5,290
22	Unserved	Boston	0	244	46	499	897
		Essex	0	297	330	364	400
		Lowell	0	0	0	54	65
		Cape	0	0	0	0	0
23			0	541	376	917	1,361
24	TOTAL		108,141	112,835	115,352	116,836	118,297

Current Method - BASE CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

			NON-HEATING SEASON (APR-OCT)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	34,359	35,715	36,293	36,880	37,449
		Essex	2,524	2,550	2,575	2,600	2,624
		Lowell	4,408	4,437	4,461	4,483	4,506
		Cape	4,370	4,423	4,471	4,516	4,561
2	Fuel Reimbursement		1,782	1,749	1,674	1,610	1,696
3	Underground Storage Refill		18,818	18,739	18,707	18,458	18,459
4	LNG Storage Refill		6,108	6,108	6,108	6,108	6,108
5	TOTAL		72,367	73,721	74,288	74,655	75,403
	RESOURCES						
6	TGP	Dracut	9	0	6	1,776	1,321
7		Dawn/Niagara	398	670	417	586	441
8		Waddington	33	53	60	64	66
9		Gulf	0	0	0	0	0
10		Market Area	31,345	32,200	32,760	30,487	31,376
11		Storage	0	0	0	0	0
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	28,797	30,665	35,366	39,180	37,973
14		Storage	61	15	0	0	0
15		AIM (Millennium)	10,763	8,568	3,936	844	2,430
16		AIM (Ramapo)	120	709	902	873	945
17		Atlantic Bridge	23	23	23	28	32
18		Beverly	0	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		0	0	0	0	0
21	LNG Withdrawal Storage		818	818	818	818	818
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		72,367	73,721	74,288	74,655	75,403

National Grid Massachusetts
Comparison of Resources and Requirements
BACKUP
(BBtu)

A. Design Heating Season Ending Resources (April 1)

	RESOURCES		2022/23	2023/24	2024/25	2025/26	2026/27
	Storage Inventories (Gross)						
1	TGP Underground Storage		206	260	255	255	254
2	AGT Underground Storage		372	350	372	621	621
3	LNG		219	219	219	219	219
	Pipeline Gas (Gross)						
4	TGP	Dracut	0	0	0	0	0
5	TGP	Dawn/Niagara	5,662	5,246	5,120	5,464	5,512
6	TGP	Waddington	4,287	4,390	4,241	1,742	1,728
7	TGP	Other Flowing	0	0	0	0	0
8	TET/AGT	Other Flowing	801	0	0	0	0
9	TET/AGT	Millennium	243	192	243	243	593
10	TET/AGT	AIM	5,396	4,989	4,688	4,900	4,739
11	TET/AGT	Atlantic Bridge	2,743	2,367	2,255	2,259	2,130
12	TET/AGT	Beverly	11,120	10,087	8,545	8,448	8,256
13	Vapor	Constellation	0	0	0	0	0

B. Thermal-Volumetric Conversion Factors (Btu/cf, unless otherwise stated)

14	System Average		1,000
15	TGP Pipeline		1,000
16	AGT Pipeline		1,000
17	LNG		1,000
18		Btu/cf	1,130 - 1,150

C. Percent Losses Associated With Storage And Pipeline

19	TGP	Dracut	0.13%
20	TGP	Dawn/Niagara	2.85%
21	TGP	Waddington	1.71%
22	TGP	Other Flowing	1.59%
23	TGP	Storage	1.45%
24	TET/AGT	Other Flowing	2.49%
25	TET/AGT	Millennium	3.66%
26	TET/AGT	AIM	3.30%
27	TET/AGT	Atlantic Bridge	5.58%
28	TET/AGT	Beverly	0.83%
29	Vapor	Constellation	0.00%
30	TET/AGT	Storage	2.97%

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

DESIGN PEAK DAY

			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	1,041	1,092	1,134	1,151	1,168
		Essex	85	86	87	87	88
		Lowell	155	157	158	159	159
		Cape	132	135	136	138	139
2	Fuel Reimbursement		24	24	24	24	24
3	Underground Storage Refill		0	0	0	0	0
4	LNG Storage Refill		0	0	0	0	0
5	TOTAL		1,437	1,492	1,538	1,559	1,579
	RESOURCES						
6	TGP	Dracut	0	0	1	1	0
7		Dawn/Niagara	87	87	87	87	87
8		Waddington	36	36	36	36	36
9		Gulf	0	0	0	0	0
10		Market Area	255	255	255	255	255
11		Storage	102	102	102	102	102
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	173	173	173	173	173
14		Storage	113	113	113	113	113
15		AIM (Millennium)	50	50	50	50	50
16		AIM (Ramapo)	53	53	53	53	53
17		Atlantic Bridge	20	23	23	23	23
18		Beverly	27	71	76	71	76
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		0	0	0	0	0
21	LNG Withdrawal Storage		520	525	522	530	515
22	Unserved	Boston	0	4	46	63	80
		Essex	0	0	1	2	16
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	4	47	65	96
24	TOTAL		1,437	1,492	1,538	1,559	1,579

Current Method - HIGH CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Normal Year
(BBtu)

			HEATING SEASON (NOV-MAR)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	69,097	73,498	75,892	77,094	78,269
		Essex	5,380	5,488	5,511	5,568	5,623
		Lowell	9,945	10,147	10,156	10,213	10,265
		Cape	8,429	8,619	8,670	8,764	8,850
2	Fuel Reimbursement		2,081	2,249	2,328	2,349	2,386
3	Underground Storage Refill		0	0	0	0	0
4	LNG Storage Refill		274	0	0	0	0
5	TOTAL		95,206	100,000	102,557	103,988	105,393
	RESOURCES						
6	TGP	Dracut	0	0	0	0	0
7		Dawn/Niagara	3,686	6,023	6,525	6,415	6,553
8		Waddington	0	52	170	2,558	2,688
9		Gulf	0	0	0	0	0
10		Market Area	35,873	37,578	38,107	36,819	37,214
11		Storage	8,248	8,193	8,148	8,140	8,145
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	22,787	23,990	24,349	24,651	25,469
14		Storage	10,568	10,589	10,568	10,319	10,319
15		AIM (Millennium)	7,595	7,645	7,595	7,595	7,004
16		AIM (Ramapo)	243	681	1,429	1,784	1,991
17		Atlantic Bridge	69	215	622	645	929
18		Beverly	300	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		5,564	5,034	5,044	5,061	5,081
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		95,206	100,000	102,557	103,988	105,393

Current Method - HIGH CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Normal Year
(BBtu)

			2022/23	2023/24	2024/25	2025/26	2026/27
			NON-HEATING SEASON (APR-OCT)				
	REQUIREMENTS						
1	Firm Sendout	Boston	32,664	34,071	34,663	35,262	35,840
		Essex	2,334	2,360	2,384	2,407	2,429
		Lowell	4,093	4,128	4,152	4,175	4,198
		Cape	4,090	4,144	4,190	4,232	4,275
2	Fuel Reimbursement		1,743	1,704	1,629	1,567	1,654
3	Underground Storage Refill		18,877	18,797	18,716	18,459	18,463
4	LNG Storage Refill		6,108	5,852	5,862	5,878	5,899
5	TOTAL		69,910	71,056	71,596	71,979	72,760
	RESOURCES						
6	TGP	Dracut	1	0	0	1,770	1,285
7		Dawn/Niagara	358	616	371	497	377
8		Waddington	12	13	14	15	16
9		Gulf	0	0	0	0	0
10		Market Area	30,260	30,954	31,479	29,426	30,324
11		Storage	0	0	0	0	0
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	27,603	29,819	34,624	38,277	37,127
14		Storage	61	15	0	0	0
15		AIM (Millennium)	10,763	8,474	3,831	741	2,329
16		AIM (Ramapo)	35	344	453	425	468
17		Atlantic Bridge	0	3	8	12	17
18		Beverly	0	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		0	0	0	0	0
21	LNG Withdrawal Storage		818	818	818	818	818
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		69,910	71,056	71,596	71,979	72,760

Current Method - HIGH CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

			HEATING SEASON (NOV-MAR)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	78,981	84,015	86,748	88,121	89,464
		Essex	6,209	6,333	6,360	6,426	6,489
		Lowell	11,442	11,675	11,686	11,751	11,810
		Cape	9,658	9,877	9,934	10,042	10,141
2	Fuel Reimbursement		2,459	2,568	2,617	2,620	2,641
3	Underground Storage Refill		0	0	0	0	0
4	LNG Storage Refill		274	0	0	0	0
5	TOTAL		109,023	114,468	117,345	118,960	120,545
	RESOURCES						
6	TGP	Dracut	1	12	13	13	12
7		Dawn/Niagara	7,757	8,239	8,360	8,016	7,994
8		Waddington	1,109	1,034	1,178	3,690	3,717
9		Gulf	0	0	0	0	0
10		Market Area	39,247	40,471	40,696	39,746	40,029
11		Storage	8,139	8,135	8,139	8,135	8,140
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	24,924	26,397	26,738	26,880	27,409
14		Storage	10,568	10,589	10,568	10,319	10,335
15		AIM (Millennium)	7,595	7,645	7,595	7,595	7,300
16		AIM (Ramapo)	2,471	2,981	3,298	3,073	3,267
17		Atlantic Bridge	985	1,158	1,360	1,373	1,468
18		Beverly	390	1,888	3,181	3,306	3,408
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		5,564	5,290	5,290	5,290	5,290
22	Unserved	Boston	0	305	547	1,077	1,658
		Essex	0	308	344	378	417
		Lowell	0	16	37	71	102
		Cape	0	0	0	0	0
23			0	629	929	1,525	2,176
24	TOTAL		109,023	114,468	117,345	118,960	120,545

Current Method - HIGH CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

			NON-HEATING SEASON (APR-OCT)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	35,004	36,513	37,144	37,783	38,400
		Essex	2,533	2,561	2,587	2,611	2,636
		Lowell	4,437	4,475	4,501	4,525	4,551
		Cape	4,378	4,435	4,484	4,529	4,576
2	Fuel Reimbursement		1,793	1,764	1,689	1,627	1,715
3	Underground Storage Refill		18,768	18,739	18,707	18,453	18,476
4	LNG Storage Refill		6,108	6,108	6,108	6,108	6,108
5	TOTAL		73,021	74,595	75,220	75,637	76,461
	RESOURCES						
6	TGP	Dracut	9	0	6	1,777	1,343
7		Dawn/Niagara	403	682	432	609	462
8		Waddington	38	65	64	68	73
9		Gulf	0	0	0	0	0
10		Market Area	31,593	32,584	33,171	30,884	31,780
11		Storage	0	0	0	0	0
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	29,164	31,020	35,726	39,582	38,407
14		Storage	61	15	0	0	0
15		AIM (Millennium)	10,763	8,601	3,968	882	2,473
16		AIM (Ramapo)	150	784	1,005	983	1,059
17		Atlantic Bridge	23	26	31	36	47
18		Beverly	0	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		0	0	0	0	0
21	LNG Withdrawal Storage		818	818	818	818	818
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		73,021	74,595	75,220	75,637	76,461

National Grid Massachusetts
Comparison of Resources and Requirements
BACKUP
(BBtu)

A. Design Heating Season Ending Resources (April 1)

	RESOURCES		2022/23	2023/24	2024/25	2025/26	2026/27
	Storage Inventories (Gross)						
1	TGP Underground Storage		255	260	255	260	254
2	AGT Underground Storage		372	350	372	621	604
3	LNG		219	219	219	219	219
	Pipeline Gas (Gross)						
4	TGP	Dracut	0	0	0	0	0
5	TGP	Dawn/Niagara	5,583	5,101	4,980	5,324	5,345
6	TGP	Waddington	4,268	4,343	4,199	1,687	1,660
7	TGP	Other Flowing	0	0	0	0	0
8	TET/AGT	Other Flowing	577	0	0	0	0
9	TET/AGT	Millennium	243	192	243	243	537
10	TET/AGT	AIM	5,337	4,826	4,510	4,735	4,541
11	TET/AGT	Atlantic Bridge	2,507	2,334	2,132	2,118	2,024
12	TET/AGT	Beverly	11,030	9,533	8,239	8,115	8,012
13	Vapor	Constellation	0	0	0	0	0

B. Thermal-Volumetric Conversion Factors (Btu/cf, unless otherwise stated)

14	System Average		1,000
15	TGP Pipeline		1,000
16	AGT Pipeline		1,000
17	LNG		1,000
18		Btu/cf	1,130 - 1,150

C. Percent Losses Associated With Storage And Pipeline

19	TGP	Dracut	0.13%
20	TGP	Dawn/Niagara	2.85%
21	TGP	Waddington	1.71%
22	TGP	Other Flowing	1.59%
23	TGP	Storage	1.45%
24	TET/AGT	Other Flowing	2.49%
25	TET/AGT	Millennium	3.66%
26	TET/AGT	AIM	3.30%
27	TET/AGT	Atlantic Bridge	5.58%
28	TET/AGT	Beverly	0.83%
29	Vapor	Constellation	0.00%
30	TET/AGT	Storage	2.97%

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

DESIGN PEAK DAY

			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	1,051	1,110	1,157	1,176	1,194
		Essex	85	86	87	88	89
		Lowell	155	158	159	160	161
		Cape	133	135	137	138	140
2	Fuel Reimbursement		24	24	24	24	24
3	Underground Storage Refill		0	0	0	0	0
4	LNG Storage Refill		0	0	0	0	0
5	TOTAL		1,448	1,513	1,563	1,586	1,608
	RESOURCES						
6	TGP	Dracut	0	1	1	1	1
7		Dawn/Niagara	87	87	87	87	87
8		Waddington	36	36	36	36	36
9		Gulf	0	0	0	0	0
10		Market Area	255	255	255	255	255
11		Storage	102	102	102	102	102
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	173	173	173	173	173
14		Storage	113	113	113	113	113
15		AIM (Millennium)	50	50	50	50	50
16		AIM (Ramapo)	53	53	53	53	53
17		Atlantic Bridge	23	23	23	23	23
18		Beverly	34	71	76	76	76
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		0	0	0	0	0
21	LNG Withdrawal Storage		521	526	524	521	510
22	Unserved	Boston	0	23	69	88	107
		Essex	0	0	1	7	22
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	23	70	95	129
24	TOTAL		1,448	1,513	1,563	1,586	1,608

Current Method - LOW CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Normal Year
(BBtu)

			HEATING SEASON (NOV-MAR)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	66,599	68,870	70,276	71,019	71,707
		Essex	5,326	5,403	5,423	5,484	5,543
		Lowell	9,754	9,847	9,851	9,926	9,978
		Cape	8,318	8,442	8,488	8,593	8,681
2	Fuel Reimbursement		2,005	2,144	2,161	2,168	2,180
3	Underground Storage Refill		0	0	0	0	0
4	LNG Storage Refill		274	0	0	0	0
5	TOTAL		92,275	94,706	96,199	97,190	98,091
	RESOURCES						
6	TGP	Dracut	0	0	0	0	0
7		Dawn/Niagara	3,145	5,119	5,366	5,375	5,506
8		Waddington	0	0	70	2,479	2,494
9		Gulf	0	0	0	0	0
10		Market Area	34,744	35,573	36,058	34,629	34,976
11		Storage	8,248	8,242	8,169	8,140	8,140
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	21,580	23,352	23,397	23,625	24,612
14		Storage	10,568	10,589	10,568	10,319	10,319
15		AIM (Millennium)	7,595	7,645	7,595	7,595	6,644
16		AIM (Ramapo)	206	178	236	180	341
17		Atlantic Bridge	51	69	69	69	69
18		Beverly	300	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		5,564	3,939	4,671	4,779	4,988
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		92,275	94,706	96,199	97,190	98,091

Current Method - LOW CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Normal Year
(BBtu)

			NON-HEATING SEASON (APR-OCT)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	30,513	31,434	31,811	32,177	32,549
		Essex	2,298	2,322	2,347	2,372	2,395
		Lowell	3,972	4,003	4,034	4,056	4,072
		Cape	4,010	4,061	4,111	4,154	4,192
2	Fuel Reimbursement		1,701	1,633	1,575	1,511	1,592
3	Underground Storage Refill		18,877	18,846	18,737	18,459	18,459
4	LNG Storage Refill		6,108	4,756	5,489	5,596	5,806
5	TOTAL		67,479	67,054	68,105	68,326	69,066
	RESOURCES						
6	TGP	Dracut	1	0	0	1,769	1,204
7		Dawn/Niagara	347	584	357	459	363
8		Waddington	10	11	12	13	14
9		Gulf	0	0	0	0	0
10		Market Area	29,239	29,624	30,053	28,058	28,918
11		Storage	0	0	0	0	0
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	26,225	27,432	32,857	36,336	35,286
14		Storage	61	15	0	0	0
15		AIM (Millennium)	10,763	8,373	3,742	638	2,208
16		AIM (Ramapo)	16	197	267	234	255
17		Atlantic Bridge	0	0	0	0	0
18		Beverly	0	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		0	0	0	0	0
21	LNG Withdrawal Storage		818	818	818	818	818
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		67,479	67,054	68,105	68,326	69,066

Current Method - LOW CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

			HEATING SEASON (NOV-MAR)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	76,125	78,724	80,329	81,178	81,964
		Essex	6,146	6,236	6,258	6,329	6,397
		Lowell	11,223	11,330	11,334	11,420	11,480
		Cape	9,531	9,673	9,726	9,846	9,947
2	Fuel Reimbursement		2,371	2,467	2,494	2,493	2,511
3	Underground Storage Refill		0	0	0	0	0
4	LNG Storage Refill		274	0	0	0	0
5	TOTAL		105,669	108,430	110,140	111,267	112,300
	RESOURCES						
6	TGP	Dracut	1	1	1	1	1
7		Dawn/Niagara	7,434	7,771	7,836	7,536	7,492
8		Waddington	726	760	919	3,432	3,513
9		Gulf	0	0	0	0	0
10		Market Area	38,541	39,291	39,307	38,183	38,464
11		Storage	8,193	8,139	8,139	8,139	8,140
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	24,118	25,125	25,506	25,658	26,342
14		Storage	10,568	10,589	10,568	10,319	10,319
15		AIM (Millennium)	7,595	7,645	7,595	7,595	7,086
16		AIM (Ramapo)	1,722	2,454	2,633	2,393	2,521
17		Atlantic Bridge	635	991	1,075	1,066	1,107
18		Beverly	300	110	976	1,113	1,653
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		5,564	5,290	5,290	5,290	5,290
22	Unserved	Boston	0	0	0	213	7
		Essex	0	262	294	329	365
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	262	294	543	372
24	TOTAL		105,669	108,430	110,140	111,267	112,300

Current Method - LOW CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

			NON-HEATING SEASON (APR-OCT)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	32,704	33,692	34,093	34,483	34,880
		Essex	2,493	2,520	2,547	2,574	2,599
		Lowell	4,306	4,339	4,373	4,397	4,414
		Cape	4,291	4,346	4,400	4,446	4,487
2	Fuel Reimbursement		1,750	1,709	1,634	1,568	1,648
3	Underground Storage Refill		18,822	18,743	18,707	18,458	18,459
4	LNG Storage Refill		6,108	6,108	6,108	6,108	6,108
5	TOTAL		70,473	71,457	71,863	72,033	72,595
	RESOURCES						
6	TGP	Dracut	8	0	5	1,775	1,278
7		Dawn/Niagara	386	648	404	553	416
8		Waddington	28	33	33	36	40
9		Gulf	0	0	0	0	0
10		Market Area	30,547	31,185	31,677	29,439	30,286
11		Storage	0	0	0	0	0
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	27,774	29,704	34,390	38,016	36,747
14		Storage	61	15	0	0	0
15		AIM (Millennium)	10,763	8,491	3,856	755	2,330
16		AIM (Ramapo)	69	542	658	620	657
17		Atlantic Bridge	21	23	23	23	23
18		Beverly	0	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		0	0	0	0	0
21	LNG Withdrawal Storage		818	818	818	818	818
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		70,473	71,457	71,863	72,033	72,595

National Grid Massachusetts
Comparison of Resources and Requirements
BACKUP
(BBtu)

A. Design Heating Season Ending Resources (April 1)

	RESOURCES		2022/23	2023/24	2024/25	2025/26	2026/27
	Storage Inventories (Gross)						
1	TGP Underground Storage		202	255	255	255	254
2	AGT Underground Storage		372	350	372	621	621
3	LNG		219	219	219	219	219
	Pipeline Gas (Gross)						
4	TGP	Dracut	0	0	0	0	0
5	TGP	Dawn/Niagara	5,905	5,568	5,504	5,804	5,847
6	TGP	Waddington	4,650	4,616	4,458	1,945	1,864
7	TGP	Other Flowing	0	0	0	0	0
8	TET/AGT	Other Flowing	1,384	376	0	0	0
9	TET/AGT	Millennium	243	192	243	243	751
10	TET/AGT	AIM	6,086	5,354	5,175	5,415	5,287
11	TET/AGT	Atlantic Bridge	2,857	2,501	2,417	2,426	2,385
12	TET/AGT	Beverly	11,120	11,310	10,444	10,307	9,767
13	Vapor	Constellation	0	0	0	0	0

B. Thermal-Volumetric Conversion Factors (Btu/cf, unless otherwise stated)

14	System Average		1,000
15	TGP Pipeline		1,000
16	AGT Pipeline		1,000
17	LNG		1,000
18		Btu/cf	1,130 - 1,150

C. Percent Losses Associated With Storage And Pipeline

19	TGP	Dracut	0.13%
20	TGP	Dawn/Niagara	2.85%
21	TGP	Waddington	1.71%
22	TGP	Other Flowing	1.59%
23	TGP	Storage	1.45%
24	TET/AGT	Other Flowing	2.49%
25	TET/AGT	Millennium	3.66%
26	TET/AGT	AIM	3.30%
27	TET/AGT	Atlantic Bridge	5.58%
28	TET/AGT	Beverly	0.83%
29	Vapor	Constellation	0.00%
30	TET/AGT	Storage	2.97%

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

DESIGN PEAK DAY

			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	1,013	1,041	1,071	1,084	1,095
		Essex	84	85	85	87	88
		Lowell	152	153	154	155	156
		Cape	131	132	134	135	137
2	Fuel Reimbursement		21	24	24	24	24
3	Underground Storage Refill		0	0	0	0	0
4	LNG Storage Refill		0	0	0	0	0
5	TOTAL		1,401	1,433	1,469	1,485	1,500
	RESOURCES						
6	TGP	Dracut	0	0	0	0	0
7		Dawn/Niagara	87	87	87	87	87
8		Waddington	35	30	35	36	36
9		Gulf	0	0	0	0	0
10		Market Area	255	255	255	255	255
11		Storage	102	102	102	102	102
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	173	173	173	173	173
14		Storage	113	113	113	113	113
15		AIM (Millennium)	50	50	50	50	50
16		AIM (Ramapo)	0	53	53	53	53
17		Atlantic Bridge	0	23	23	23	23
18		Beverly	60	23	71	66	71
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		0	0	0	0	0
21	LNG Withdrawal Storage		526	523	507	525	527
22	Unserved	Boston	0	0	0	0	7
		Essex	0	0	0	1	2
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	1	9
24	TOTAL		1,401	1,433	1,469	1,485	1,500

National Grid Massachusetts
Comparison of Resources and Requirements
Normal Year
(BBtu)

			Annual				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	100,475	105,522	108,175	109,823	111,425
		Essex	7,693	7,818	7,862	7,940	8,016
		Lowell	13,969	14,173	14,188	14,260	14,329
		Cape	12,499	12,736	12,822	12,956	13,085
2	Fuel Reimbursement		3,793	3,900	3,892	3,849	3,966
3	Underground Storage Refill		18,877	18,822	18,713	18,459	18,463
4	LNG Storage Refill		6,381	5,829	5,834	5,848	5,867
5	TOTAL		163,688	168,799	171,486	173,134	175,152
	RESOURCES						
6	TGP	Dracut	1	0	0	1,770	1,260
7		Dawn/Niagara	3,667	6,366	6,603	6,654	6,671
8		Waddington	12	36	125	2,557	2,570
9		Gulf	0	0	0	0	0
10		Market Area	65,569	67,658	68,674	65,325	66,606
11		Storage	8,248	8,218	8,145	8,140	8,145
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	49,914	53,181	58,187	62,185	61,873
14		Storage	10,629	10,604	10,568	10,319	10,319
15		AIM (Millennium)	18,358	16,088	11,397	8,302	9,220
16		AIM (Ramapo)	266	745	1,657	1,539	2,029
17		Atlantic Bridge	69	73	296	497	592
18		Beverly	300	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		6,381	5,829	5,834	5,848	5,867
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		163,688	168,799	171,486	173,134	175,152

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

			Annual				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	112,560	118,243	121,231	123,073	124,863
		Essex	8,718	8,860	8,909	8,998	9,084
		Lowell	15,802	16,035	16,050	16,131	16,209
		Cape	14,013	14,281	14,377	14,526	14,671
2	Fuel Reimbursement		4,215	4,290	4,259	4,198	4,305
3	Underground Storage Refill		18,818	18,739	18,707	18,458	18,459
4	LNG Storage Refill		6,381	6,108	6,108	6,108	6,108
5	TOTAL		180,508	186,556	189,640	191,491	193,700
	RESOURCES						
6	TGP	Dracut	10	1	18	1,789	1,325
7		Dawn/Niagara	8,075	8,764	8,637	8,461	8,268
8		Waddington	1,122	1,039	1,195	3,699	3,715
9		Gulf	0	0	0	0	0
10		Market Area	70,368	72,381	73,100	69,841	71,054
11		Storage	8,189	8,135	8,139	8,139	8,140
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	53,497	56,760	61,812	65,768	65,162
14		Storage	10,629	10,604	10,568	10,319	10,319
15		AIM (Millennium)	18,358	16,213	11,531	8,438	9,675
16		AIM (Ramapo)	2,533	3,529	4,022	3,781	4,014
17		Atlantic Bridge	772	1,147	1,260	1,261	1,394
18		Beverly	300	1,333	2,875	2,972	3,165
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		6,381	6,108	6,108	6,108	6,108
22	Unserved	Boston	0	244	46	499	897
		Essex	0	297	330	364	400
		Lowell	0	0	0	54	65
		Cape	0	0	0	0	0
23			0	541	376	917	1,361
24	TOTAL		180,508	186,556	189,640	191,491	193,700

National Grid Massachusetts
Comparison of Resources and Requirements
Normal Year
(BBtu)

			Annual				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	101,761	107,569	110,556	112,355	114,109
		Essex	7,715	7,848	7,895	7,975	8,053
		Lowell	14,038	14,275	14,309	14,388	14,463
		Cape	12,519	12,763	12,860	12,996	13,125
2	Fuel Reimbursement		3,824	3,953	3,957	3,916	4,040
3	Underground Storage Refill		18,877	18,797	18,716	18,459	18,463
4	LNG Storage Refill		6,381	5,852	5,862	5,878	5,899
5	TOTAL		165,117	171,056	174,154	175,967	178,152
	RESOURCES						
6	TGP	Dracut	1	0	0	1,770	1,285
7		Dawn/Niagara	4,044	6,639	6,895	6,913	6,930
8		Waddington	12	65	184	2,572	2,703
9		Gulf	0	0	0	0	0
10		Market Area	66,133	68,532	69,586	66,245	67,538
11		Storage	8,248	8,193	8,148	8,140	8,145
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	50,390	53,809	58,972	62,928	62,596
14		Storage	10,629	10,604	10,568	10,319	10,319
15		AIM (Millennium)	18,358	16,119	11,425	8,335	9,332
16		AIM (Ramapo)	277	1,025	1,883	2,209	2,459
17		Atlantic Bridge	69	218	629	658	945
18		Beverly	300	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		6,381	5,852	5,862	5,878	5,899
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		165,117	171,056	174,154	175,967	178,152

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

			Annual				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	113,985	120,528	123,893	125,904	127,864
		Essex	8,742	8,894	8,947	9,037	9,125
		Lowell	15,880	16,150	16,187	16,276	16,361
		Cape	14,036	14,312	14,418	14,571	14,716
2	Fuel Reimbursement		4,252	4,332	4,306	4,247	4,356
3	Underground Storage Refill		18,768	18,739	18,707	18,453	18,476
4	LNG Storage Refill		6,381	6,108	6,108	6,108	6,108
5	TOTAL		182,044	189,063	192,565	194,597	197,006
	RESOURCES						
6	TGP	Dracut	11	12	19	1,790	1,355
7		Dawn/Niagara	8,159	8,921	8,792	8,624	8,456
8		Waddington	1,147	1,098	1,242	3,758	3,790
9		Gulf	0	0	0	0	0
10		Market Area	70,840	73,056	73,867	70,630	71,808
11		Storage	8,139	8,135	8,139	8,135	8,140
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	54,087	57,418	62,464	66,462	65,816
14		Storage	10,629	10,604	10,568	10,319	10,335
15		AIM (Millennium)	18,358	16,246	11,563	8,476	9,773
16		AIM (Ramapo)	2,621	3,765	4,303	4,055	4,326
17		Atlantic Bridge	1,007	1,183	1,391	1,409	1,515
18		Beverly	390	1,888	3,181	3,306	3,408
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		6,381	6,108	6,108	6,108	6,108
22	Unserved	Boston	0	305	547	1,077	1,658
		Essex	0	308	344	378	417
		Lowell	0	16	37	71	102
		Cape	0	0	0	0	0
23			0	629	929	1,525	2,176
24	TOTAL		182,044	189,063	192,565	194,597	197,006

National Grid Massachusetts
Comparison of Resources and Requirements
Normal Year
(BBtu)

			Annual				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	97,112	100,303	102,087	103,196	104,257
		Essex	7,624	7,725	7,771	7,857	7,939
		Lowell	13,726	13,850	13,885	13,982	14,051
		Cape	12,328	12,503	12,599	12,747	12,874
2	Fuel Reimbursement		3,706	3,776	3,736	3,679	3,772
3	Underground Storage Refill		18,877	18,846	18,737	18,459	18,459
4	LNG Storage Refill		6,381	4,756	5,489	5,596	5,806
5	TOTAL		159,754	161,760	164,304	165,515	167,157
	RESOURCES						
6	TGP	Dracut	1	0	0	1,769	1,204
7		Dawn/Niagara	3,492	5,703	5,723	5,834	5,869
8		Waddington	10	11	83	2,493	2,508
9		Gulf	0	0	0	0	0
10		Market Area	63,983	65,197	66,110	62,688	63,895
11		Storage	8,248	8,242	8,169	8,140	8,140
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	47,805	50,784	56,253	59,961	59,898
14		Storage	10,629	10,604	10,568	10,319	10,319
15		AIM (Millennium)	18,358	16,018	11,337	8,233	8,853
16		AIM (Ramapo)	222	375	503	414	596
17		Atlantic Bridge	51	69	69	69	69
18		Beverly	300	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		6,381	4,756	5,489	5,596	5,806
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		159,754	161,760	164,304	165,515	167,157

National Grid Massachusetts
Comparison of Resources and Requirements
Design Year
(BBtu)

			Annual				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	108,829	112,417	114,422	115,661	116,844
		Essex	8,640	8,755	8,806	8,903	8,997
		Lowell	15,528	15,669	15,707	15,817	15,895
		Cape	13,822	14,019	14,126	14,292	14,434
2	Fuel Reimbursement		4,120	4,176	4,128	4,062	4,159
3	Underground Storage Refill		18,822	18,743	18,707	18,458	18,459
4	LNG Storage Refill		6,381	6,108	6,108	6,108	6,108
5	TOTAL		176,143	179,888	182,003	183,300	184,895
	RESOURCES						
6	TGP	Dracut	9	1	6	1,776	1,279
7		Dawn/Niagara	7,820	8,419	8,240	8,089	7,908
8		Waddington	754	793	952	3,468	3,553
9		Gulf	0	0	0	0	0
10		Market Area	69,087	70,476	70,984	67,621	68,749
11		Storage	8,193	8,139	8,139	8,139	8,140
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	51,891	54,829	59,896	63,674	63,090
14		Storage	10,629	10,604	10,568	10,319	10,319
15		AIM (Millennium)	18,358	16,136	11,451	8,349	9,416
16		AIM (Ramapo)	1,791	2,996	3,291	3,013	3,178
17		Atlantic Bridge	656	1,014	1,097	1,089	1,130
18		Beverly	300	110	976	1,113	1,653
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		6,381	6,108	6,108	6,108	6,108
22	Unserved	Boston	0	0	0	213	7
		Essex	0	262	294	329	365
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	262	294	543	372
24	TOTAL		176,143	179,888	182,003	183,300	184,895

National Grid Massachusetts
Comparison of Resources and Requirements
Cold Snap Sensitivity Scenario
(BBtu)

			Annual				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	104,315	109,544	112,338	114,040	115,694
		Essex	8,015	8,143	8,191	8,272	8,352
		Lowell	14,555	14,765	14,783	14,857	14,929
		Cape	12,978	13,222	13,314	13,453	13,587
2	Fuel Reimbursement		3,948	4,063	4,032	3,977	4,084
3	Underground Storage Refill		18,867	18,752	18,708	18,456	18,462
4	LNG Storage Refill		6,381	6,108	6,108	6,108	6,108
5	TOTAL		169,060	174,597	177,473	179,163	181,216
	RESOURCES						
6	TGP	Dracut	1	0	0	1,769	1,251
7		Dawn/Niagara	6,399	6,988	7,079	7,119	7,110
8		Waddington	805	455	700	3,163	3,221
9		Gulf	0	0	0	0	0
10		Market Area	65,666	67,990	68,872	65,483	66,747
11		Storage	8,238	8,147	8,140	8,137	8,143
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	50,888	54,307	59,267	63,093	62,757
14		Storage	10,629	10,604	10,568	10,319	10,319
15		AIM (Millennium)	18,358	16,087	11,402	8,305	9,217
16		AIM (Ramapo)	989	2,646	2,955	2,768	2,877
17		Atlantic Bridge	131	927	1,082	1,108	1,178
18		Beverly	300	189	1,099	1,479	1,996
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		6,381	6,108	6,108	6,108	6,108
22	Unserved	Boston	0	0	25	107	58
		Essex	0	147	176	205	234
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	147	201	312	292
24	TOTAL		169,060	174,597	177,473	179,163	181,216

Current Method - COLD SNAP CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Cold Snap Sensitivity Scenario
(BBtu)

			HEATING SEASON (NOV-MAR)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	72,263	76,227	78,479	79,631	80,752
		Essex	5,691	5,795	5,819	5,878	5,936
		Lowell	10,492	10,675	10,671	10,725	10,776
		Cape	8,895	9,089	9,137	9,233	9,325
2	Fuel Reimbursement		2,217	2,370	2,414	2,422	2,443
3	Underground Storage Refill		0	0	0	0	0
4	LNG Storage Refill		274	0	0	0	0
5	TOTAL		99,832	104,157	106,520	107,890	109,232
	RESOURCES						
6	TGP	Dracut	0	0	0	0	0
7		Dawn/Niagara	6,047	6,386	6,714	6,631	6,740
8		Waddington	794	442	686	3,148	3,205
9		Gulf	0	0	0	0	0
10		Market Area	35,701	37,459	37,812	36,452	36,807
11		Storage	8,238	8,147	8,140	8,137	8,143
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	23,656	24,574	24,768	25,009	25,862
14		Storage	10,568	10,589	10,568	10,319	10,319
15		AIM (Millennium)	7,595	7,645	7,595	7,595	6,925
16		AIM (Ramapo)	964	2,360	2,564	2,409	2,478
17		Atlantic Bridge	131	927	1,082	1,108	1,175
18		Beverly	300	189	1,099	1,479	1,996
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		274	0	0	0	0
21	LNG Withdrawal Storage		5,564	5,290	5,290	5,290	5,290
22	Unserved	Boston	0	0	25	107	58
		Essex	0	147	176	205	234
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	147	201	312	292
24	TOTAL		99,832	104,157	106,520	107,890	109,232

Current Method - COLD SNAP CASE

National Grid Massachusetts
Comparison of Resources and Requirements
Cold Snap Sensitivity Scenario
(BBtu)

			NON-HEATING SEASON (APR-OCT)				
			2022/23	2023/24	2024/25	2025/26	2026/27
	REQUIREMENTS						
1	Firm Sendout	Boston	32,052	33,317	33,859	34,409	34,942
		Essex	2,324	2,348	2,371	2,394	2,416
		Lowell	4,062	4,090	4,112	4,132	4,153
		Cape	4,083	4,133	4,177	4,219	4,262
2	Fuel Reimbursement		1,731	1,693	1,618	1,555	1,641
3	Underground Storage Refill		18,867	18,752	18,708	18,456	18,462
4	LNG Storage Refill		6,108	6,108	6,108	6,108	6,108
5	TOTAL		69,228	70,440	70,953	71,273	71,984
	RESOURCES						
6	TGP	Dracut	1	0	0	1,769	1,250
7		Dawn/Niagara	352	602	364	488	370
8		Waddington	12	13	14	15	16
9		Gulf	0	0	0	0	0
10		Market Area	29,965	30,531	31,060	29,030	29,941
11		Storage	0	0	0	0	0
12	TET/AGT	Gulf	0	0	0	0	0
13		Market Area	27,232	29,733	34,499	38,085	36,895
14		Storage	61	15	0	0	0
15		AIM (Millennium)	10,763	8,442	3,807	710	2,292
16		AIM (Ramapo)	24	286	391	359	400
17		Atlantic Bridge	0	0	0	0	3
18		Beverly	0	0	0	0	0
19	Vapor	Constellation	0	0	0	0	0
20	Liquid Refill		0	0	0	0	0
21	LNG Withdrawal Storage		818	818	818	818	818
22	Unserved	Boston	0	0	0	0	0
		Essex	0	0	0	0	0
		Lowell	0	0	0	0	0
		Cape	0	0	0	0	0
23			0	0	0	0	0
24	TOTAL		69,228	70,440	70,953	71,273	71,984

AGREEMENTS FOR GAS SUPPLY - KEY

Key (use on Table G-24 (A))	Company and Contract

1. <u>Pipeline Companies</u>

Alqonquin	Algonquin Gas Transmission Company
Eastern Gas	Eastern Gas Transmission and Storage, Inc.
Enbridge	Enbridge Gas, Inc.
Iroquois	Iroquois Gas Transmission System
Millennium	Millennium Pipeline Company
PNGTS	Portland Natural Gas Transmission System
Tennessee	Tennessee Gas Pipeline Company
Texas Eastern	Texas Eastern Gas Transmission Company
TransCanada	TransCanada Pipeline
Transco	Transcontinental Gas Pipeline Corporation

2. <u>SNG</u> (Not Applicable)

3. <u>LNG</u> (Not Applicable)

4. <u>Propane</u> (Not Applicable)

5. <u>Gas Supply</u>

Castleton Commodities	Castleton Commodities Merchant Trading L.P.
Constellation LNG	Constellation LNG, LLC
Emera Energy	Emera Energy Services, Inc.
Freepoint Commodities	Freepoint Commodities LLC
Gaz Metro LNG	Gaz Metro LNG, L.P.
Repsol	Repsol Energy North America Corporation
UGI	UGI Energy Services, LLC

<u>Storage and Leased Facilities</u>

6. <u>Storage</u>

Eastern Gas	Eastern Gas Transmission and Storage, Inc.
Honeoye	Honeoye Storage Corporation
National Grid LNG	National Grid LNG, LP
Tennessee	Tennessee Gas Pipeline Company
Texas Eastern	Texas Eastern Gas Transmission Company

7. Leasing (Not Applicable)

Other: ______________________________

Key (use on Table G-24 (A))

Contract Type

PG	Purchase of Gas
SG	Sale of Gas
LF	Lease of Gas Manufacturing or Storage Facility
SS	Storage Service
FT	Firm Transportation Service
BT	Best-Efforts Transportation Service

Other: ______________________________

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Evergreen	Notes
Boston Gas	Algonquin	99058	AFT-1	58,456	21,336,440	10/31/2024	Yes	Part-284 transportation service (365-day) used to transport gas: 6,912 MMBtu from the interconnect with Transco at Centerville, NJ, 49,544 MMBtu from Lambertville, NJ to National Grid citygates.and from the AGT/TGP interconnect at Mendon, MA (2,000 MMBtu/day) to National Grid citygates.
Boston Gas	Algonquin	934001	AFT-1	20,771	7,581,415	10/31/2024	Yes	Part-284 transportation service (365-day) used to transport gas from the AGT/TETCO interconnect at Lambertville, NJ to National Grid citygates.
Boston Gas	Algonquin	93002CR	AFT-1	44,699	13,513,671	10/31/2024	Yes	Part-284 service with a seasonally adjusted MDQ of 44,699 MMBtu/day, used to transport gas from the AGT/TETCO interconnect at Lambertville, NJ to National Grid citygates.
Boston Gas	Algonquin	9B100	AFT-1	33,910	7,200,254	10/31/2024	Yes	Part-284 service with a seasonally adjusted MDQ of 33,910 MMBtu/day, used to transport gas from the AGT/TETCO interconnect at Lambertville, NJ to National Grid citygates.
Boston Gas	Algonquin	9221	AFT-1	23,970	8,749,050	10/31/2024	Yes	Part-284 transportation service (365 day) used to transport gas from the AGT/TGP interconnect at Mendon, MA to National Grid citygates.
Boston Gas	Algonquin	99012	AFT-1	35,000	4,200,000	10/31/2024	Yes	Part-284 transportation service (120-day/November 16th - March 15th) used to deliver gas from NGLNG in Providence, RI to National Grid citygates.
Boston Gas	Algonquin	510798	AFT-1	100,000	36,500,000	1/6/2032	Negotiated Rate through Primary Term	AIM Project capacity: Transporation service (365-day) used to transport gas from the AGT/Millenium interconnect at Ramapo, NY to National Grid citygates, including to the West Roxbury Lateral.
Boston Gas	Algonquin	510807	AFT-CLW	100,000	36,500,000	12/4/2031	Negotiated Rate through Primary Term	AIM Project capacity: Transportation service (365-day) used to transport gas from the interconnect at AGT Mainline & Head of West Roxbury Lateral to the new West Roxbury citygate (Meter No. 00838) located in West Roxbury, MA.
Boston Gas	Algonquin	933003	AFT-1 (PSS-T)	2,222	811,030	3/31/2024	Yes	Part-284 transportation service (365-day) used to transport gas from the AGT/TETCO interconnect at Lambertville, NJ to National Grid citygates.
Boston Gas	Algonquin	93003ECR	AFT-E	112,057	35,297,541	10/31/2025	Yes	Part-284 no-notice service with a seasonally adjusted MDQ used to transport gas from the AGT/TETCO interconnect at Lambertville, NJ to National Grid citygates. **Contract 93002EA (95,594 MMBtu) was terminated and combined with this contract effective July 1, 2022.**
Boston Gas	Algonquin	98002C	AFT-E	7,327	2,378,365	10/31/2024	Yes	Part 284 no-notice service (365-day) used to transport gas from the AGT/TETCO interconnect at Lambertville, NJ to National Grid citygates.
Boston Gas	Algonquin	510364	AFT-1	38,000	13,870,000	11/19/2023	Yes	Part-284 transportation service (365-day) used to transport gas from TGP/AGT-interconnect at Mendon, MA to the interconnect at the AGT G-System.
Boston Gas	Algonquin	510365	AFT-CL	38,000	13,870,000	11/19/2023	Yes	Part-284 transportation service (365-day) used to transport gas from the interconnect at AGT G-Sys Bourne, MA & Canal Lateral to the Tap to MS806 on G-24 Lateral.

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Evergreen	Notes
Boston Gas	Algonquin	510366	AFT-CLCC	38,000	13,870,000	11/19/2023	Yes	Part-284 transportation service (365-day) used to transport gas from the interconnect at AGT G-Sys Bourne, MA & Canal Lateral to the Tap to MS806 on G-24 Lateral to Meter 00829 Cape Cod Expansion - Sandwich, MA.
Boston Gas	Algonquin	511110	AFT-1AB	19,000	6,935,000	10/31/2034	Negotiated Rate through Primary Term	Atlantic Bridge capacity with receipt points at either Ramapo, NY or Mahwah, NJ and a delivery point of East Braintree, MA. Full contract volume for 19,000 MMBtu per day begins 11/1/2020 through 10/31/2034 with renewal rights.
Boston Gas	Algonquin	511140	AFT-1AB	2,833	1,034,045	10/31/2024	Yes	Atlantic Bridge capacity with receipt points at either Ramapo, NY or Mahwah, NJ and a delivery point of East Braintree, MA.
Boston Gas	Algonquin	511178	AFT-1H	75,000	27,375,000	10/31/2023	Yes	Part-284 transportation service (365-day) used to transport gas from M&N expansion-interconnect at Beverly, MA to National Grid city gates. Contract volume for 75,000 MMBtu per day begins 11/1/2022 through 10/31/2023 with renewal rights.
Boston Gas	Eastern Gas	100015	FTNN	12,978	4,736,970	3/31/2027	Yes	Part-284 transportation service (365-day) used to transport gas received from interconnects at Lebanon, PA or Dominion South Point with deliverability into TETCO at Leidy.
Boston Gas	Eastern Gas	5G2191	FT-GSS	2,222	335,522	3/31/2027	Yes	Part-284 transportation service (151-day) used to transport gas received from Dominion GSS storage (300114) to the Dominion/TETCO interconnect at Oakford, PA.
Boston Gas	Enbridge	M12197	M12	16,980	6,197,700	10/31/2025	Yes	Canadian transportation service (365-day) used to transport gas from Dawn to the Enbridge/TransCanada interconnect at Parkway.
Boston Gas	Enbridge	M12273	M12	57,180	20,870,700	10/31/2040	Yes	Canadian transportation service (365-day) used to transport gas from Dawn to the Enbridge/TransCanada interconnect at Parkway.
Boston Gas	Iroquois	42001	RTS-1	52,203	19,054,095	11/1/2024	Yes	Part-284 transportation service (365-day) used to transport Canadian supply from Waddington to the Iroquois/TGP interconnect at Wright, NY.
Boston Gas	Millennium	210162	FT-1	50,000	18,250,000	3/31/2034	Negotiated Rate through Primary Term	Millennium expansion of its existing pipeline facilities which extend from an interconnect with Empire at Corning into Algonquin at Ramapo, NY to transport incremental natural gas to Algonquin at Ramapo, NY (Expansion Facilities).
Boston Gas	PNGTS	233314	FT	57,068	20,829,820	10/31/2040	PNGTS Negotiated Rate through Primary Term	This contract is used to transport volumes from East Hereford, Quebec to the PNGTS interconnect with TGP at Dracut, MA.
Boston Gas	Tennessee	623	FT-A	74,515	27,197,975	10/31/2024	Yes	Part-284 transportation service (365-day), used to transport gas from the FS-MA storage field (68,431 MMBtu) and from Rose Lake (6,084 MMBtu) to National Grid citygates.
Boston Gas	Tennessee	2062	FT-A	152,537	55,676,005	10/31/2024	Yes	Transportation contract used to transport gas from the access area (zones 0 and 1) and the storage field (zone 4) to National Grid citygates. Primary receipts of 129,656 MMBtu/day from zones 0 and 1 and 22,881 MMBtu/day from zone 4.

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Evergreen	Notes
Boston Gas	Tennessee	20241	FT-A	58,627	21,398,855	10/31/2024	Yes	Part-284 transportation service (365-day) used to transport gas from two storage fields (Honeoye, FS-MA) to National Grid city gates. Also used to transport 25,600 MMBtu/day from Iroquois at Wright, NY to National Grid citygates and 20,000 MMBtu/day from Iroquois to the Tennessee interconnect with Algonquin at Mendon, MA.
Boston Gas	Tennessee	109877	FT-A	43,200	15,768,000	10/31/2027	Yes	Part-284 transportation service (365-day) used to transport gas from the TGP/Maritimes interconnect at Dracut, MA to National Grid citygates.
Boston Gas	Tennessee	330568	FT-A	13,868	5,061,820	10/31/2038	Yes	FT-A Transportation Agreement (Incremental using existing capacity) for deliveries from Dracut/Maritimes in Middlesex, MA to Acton Sales/Boston Gas in Middlesex, MA with an MDQ of 13,868 MMBtu/day.
Boston Gas	Tennessee	256	FT-A	18,154	6,626,210	10/31/2024	Yes	Part-284 transportation service (365) used to transport gas from Canadian Supply from Niagara, NY to National Grid citygates and to transport gas from Iroquois at Wright, NY to National Grid citygates or the TGP/AGT interconnect at Mendon, MA.
Boston Gas	Tennessee	64023	FT-A	50,715	18,510,975	10/31/2027	Negotiated Rate	Part 284 transportation service (365-day) used to transport gas from the access area (zones 0 and 1) to National Grid citygates and to the TGP/AGT interconnect at Mendon, MA for delivery to Cape Cod AGT (19,388 MMBtu/day).
Boston Gas	Tennessee	64024	FT-A	61,985	22,624,525	10/31/2027	Negotiated Rate	Part 284 transportation service (365-day) used to transport gas from the access area (zones 0 and 1) to National Grid citygates and to the TGP/AGT intercconnect at Mendon, MA for delivery to Cape Cod AGT (19,140 MMBtu/day).
Boston Gas	Texas Eastern	331009	FTS-7	29,915	10,918,975	10/31/2024	Yes	Part-157 (7C) service (FTS-7) (365-day) used to transport gas from Dominion storage at Oakford, PA to TETCO interconnect with AGT at Lambertville, NJ.
Boston Gas	Texas Eastern	800285	FT-1	97,626	35,633,490	10/31/2024	Yes	Part-284 transportation service (365-day) used to transport gas from the access areas (STX, ETX, ELA and WLA) and Market Areas (M1 and M2) to the TETCO/AGT interconnect at Lambertville, NJ. **Contract 800313 (9,869 MMBtu) will be terminated and combined with 800285 (87,757 MMBtu) effective November 1, 2022 for a total of 97,626 MMBtu.**
Boston Gas	Texas Eastern	800286	CDS	43,347	15,821,655	10/31/2027	Yes	Part-284 transportation service (365-day) used to transport gas from the access areas (STX, ETX, ELA and WLA) and Market Areas (M1 and M2) to the TETCO/AGT interconnect at Lambertville, NJ. **Contract 800469 (10,731 MMBtu) will be terminated and combined with 800286 (32,616 MMBtu) effective November 1, 2022 for a total of 43,347 MMBtu.**
Boston Gas	Texas Eastern	800287	FT-1	23,720	8,657,800	4/30/2028	Yes	Part-284 transportation service (365-day) used to transport gas from Dominion at Leidy, PA and Oakford, PA to the TETCO interconnect with AGT at Lambertville, NJ. **Contract 800400 (2,326 MMBtu) was terminated and combined with this contract effective October 1, 2022.**

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Annual Quantity	Expiration Date	Evergreen	Notes
Boston Gas	Texas Eastern	331700	FTS-7	3,016	1,100,840	4/15/2025	Yes	Part-157 (7C) service (FTS-7) (365-day) used to transport gas from Dominion storage at Oakford, PA to TETCO interconnect with AGT at Lambertville, NJ.
Boston Gas	Texas Eastern	331800	FTS-8	985	359,525	3/31/2025	Yes	Part-157 (7C) service (FTS-8) (365-day) used to transport gas from Dominion storage at Oakford, PA to TETCO's interconnect with AGT at Lambertville, NJ.
Boston Gas	TransCanada	63478	FT	16,793	6,129,445	10/31/2026	Yes	Canadian transportation service (365-day) used to transport gas from Parkway to the TransCanada/IRQ interconnect at Waddington.
Boston Gas	TransCanada	64272	FT	57,180	20,870,700	10/31/2040	Yes	Canadian Transportation service (365-day). This contract is used to transport volumes from Parkway-Union to TransCanada interconnect with PNGTS at East Hereford.
Boston Gas	Transco	1006425	FT	6,911	2,522,515	5/31/2024	Yes	Part-284 transportation service (365-day) used to transport gas from Wharton, PA to the Transco/AGT interrconnect at Centerville, NJ.

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDWQ	Annual Quantity MSQ	Expiration Date	Evergreen	Notes
Boston Gas	Eastern Gas	600051	GSS-TE Storage	53,457	5,521,661	3/31/2027	Yes	Part-284 storage service (110-day) that provides storage capacity with an injection rate of 30,676 MMBtu/day. **Contracts 600020 (42,457 MMBtu withdrawal rights) and 561286 (11,000 MMBtu withdrawal rights) were terminated and combined for this contract effective April 1, 2022.**
Boston Gas	Eastern Gas	5F5800	GSS Storage	2,222	222,200	3/31/2027	Yes	Part-284 storage service (100-day) with an injection rate of 1,234 MMBtu/day.
Boston Gas	Eastern Gas	5F5801	GSS Storage	104	10,400	3/31/2027	Yes	Part-284 storage service (100-day) with an injection rate of 58 MMBtu/day.
Boston Gas	Honeoye		SS-NY Storage	6,150	981,120	4/1/2024	Yes	Part-157 (7C) storage service that provides storage capacity with an injection rate of 4,672 MMBtu/day.
Boston Gas	National Grid LNG, LP	LNG006	NGLNG	35,000	1,159,664	10/31/2024	Yes	LNG storage contract (LNG006). The associated Algonquin transportation contract is AGT #99012 from Dey Street to Company's citygates.
Boston Gas	Tennessee	527	FS-MA Storage	95,415	7,603,290	10/31/2024	Yes	Part-284 storage service that provides storage capacity with an injection rate of 50,689 MMBtu/day. **Contract 524 (14,150 MMBtu withdrawal rights) was terminated and combined with this contract effective December 1, 2021.**
Boston Gas	Texas Eastern	400225	SS-1 Storage	75,740	5,431,577	4/30/2028	Yes	Part-284 storage and transportation service that provides storage capacity with an injection rate of 27,919 MMBtu. **Contract 400200 (6,969 MMBtu withdrawal rights) was terminated and combined with this contract effective July 1, 2022.**

Shipper	Supply Company	Contract No.	MDQ	Annual Quantity	Expiration Date	Evergreen	Notes
Boston Gas	Castleton Commodities		57,180	10,349,580	4/30/2023	N/A	Supply Agreement pursuant to an AMA between Boston Gas and Castleton Commodities that provides gas commodity from Dawn, Ontario to East Hereford. Delivered volume is 57,180 MMBtu.
Boston Gas	Freepoint Commodities		16,793	2,535,743	3/31/2023	N/A	Supply Agreement pursuant to an AMA between Boston Gas and Freepoint that provides gas commodity from Dawn, Ontario to Waddington. Delivered volume is 16,793 MMBtu.
Boston Gas	Emera Energy		25,000	4,525,000	4/30/2023	N/A	Supply Agreement pursuant to an AMA between Boston Gas and Emera that provides gas commodity from Corning-Empire Pipeline to Ramapo AGT. Delivered volume is 25,000 MMBtu.
Boston Gas	Repsol		60,000	300,000	3/31/2023	N/A	Supply Agreement between Boston Gas and Repsol with an MDQ of 60,000 MMBtu and MSQ of 300,000 MMBtu.
Boston Gas	Gaz Metro LNG		8,000	1,117,000	11/30/2022	N/A	Summer liquid refill agreement for Firm Liquid Service with a maximum annual quantity of 1,117,000 MMBtu.
Boston Gas	UGI		9,000	1,150,000	11/30/2022	N/A	Summer liquid refill agreement for Firm Liquid Service with a maximum annual quantity of 1,150,000 MMBtu.
Boston Gas	Constellation LNG		7,600	273,600	3/31/2023	N/A	Winter liquid refill agreement for Firm Liquid Service with a maximum annual quantity of 273,600 MMBtu.