Northern Utilities, Inc.

2015 Integrated Resource Plan

5-Year Natural Gas Portfolio Plan

Submitted jointly to the Maine Public Utilities Commission and
New Hampshire Public Utilities Commission

January 16, 2015

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I. Executive Summary

The purpose of this Integrated Resource Plan ("2015 IRP") filing is to review Northern Utilities, Inc.'s ("Northern" or the "Company") projected long-term resource needs over the coming five year planning period and discuss the planning processes used by Northern to develop a natural gas portfolio that provides reliable service to customers at a reasonable cost.

Consistent with the content requirements of the 2011 IRP Settlement, the 2015 IRP provides details regarding the development of the demand forecast, including total system throughput under design (cold) weather conditions and conversion of the demand forecast into long-term planning load requirements. The IRP then reviews the current portfolio of long-term assets and compares the supplies available from the current portfolio to the forecast of planning load requirements in order to assess incremental resource needs. Potential supply alternatives, such as new pipeline projects proposed for the region or the possible addition of new peaking facilities on the Company's system, are reviewed and the Company's long-term resource decision making process is explained.

Due to ongoing negotiations and current open seasons, the IRP does not select or propose any specific project or resource for addition to the long-term portfolio. However, the IRP fully documents current market dynamics in order to establish a context for possible long-term contracting activity, Northern's current forecast of resource requirements over the planning period and the analytical framework Northern uses to evaluate potential new resources. The IRP also describes state-level regulatory issues that could impact Northern's contracting decisions.

The New England region is currently experiencing several market structure changes that significantly impact gas supply planning for local distribution companies ("LDCs"). The current market environment is marked by the contrast of declining supplies from Atlantic Canada, which existing infrastructure can deliver to the Company's system, and abundant supplies from the Marcellus region, which existing infrastructure cannot adequately deliver to the Company's system. Specifically, the off-shore Nova Scotia resource basin, which includes the Sable Island and Deep Panuke developments, are producing less natural gas than previously forecast and the remaining life of the resource basin is unclear. In addition, imported LNG deliveries at the four regional terminals have declined significantly over the last several years. At the same time, the demand for natural gas by both the end-use segment (e.g., residential customers converting from alternative fuels to natural gas) and the power generation segment (e.g., higher utilization of existing plants) has grown. This increase in natural gas demand, the reduction in certain natural gas supply sources, and the pipeline capacity constraint between the Mid-Atlantic production area and New England have placed upward pressure on the New England City Gate prices as well as increased price volatility and occasional scarcity of supply.

The forecast of firm customer demand and the subsequent determination of planning load requirements establish the resource need that Northern expects to meet over the planning horizon.

Northern developed a detailed demand forecast based on separate models of customer segment demand (*e.g.*, Residential heating customers,) for the Maine Division and New Hampshire Division. The demand forecasts were adjusted for expected energy efficiency savings and translated into city gate throughput requirements. The demand forecast was also disaggregated into customer segments based upon capacity assignment categories, since Northern does not plan for all customers, as described below. In addition, the Company's demand forecast was calibrated to reflect extreme cold, or design, weather conditions. Northern uses a design planning standard of 1 occurrence in 33 year probability for supply planning, which is similar to other LDCs in the region. Forecasts of planning load were developed for normal year, design year and design day conditions.

Table I-1 shows Northern's customer count forecast for the five year planning period, which reflects an average annual growth rate of almost 3 percent or the addition of nearly 10,000 customers over the forecast period.

Table I-1: Northern Projected Customer Counts

Split Year	Residential Customers	C&I Sales Customers	C&I Transport Customers	Northern Customers
2014/15	45,483	13,843	3,440	62,767
2015/16	47,006	14,306	3,510	64,822
2016/17	48,550	14,682	3,574	66,806
2017/18	50,115	14,983	3,628	68,727
2018/19	51,697	15,227	3,670	70,594
2019/20	53,289	15,433	3,704	72,426
CAGR	3.2%	2.2%	1.5%	2.9%

Table I-2 presents the forecast of Northern's Design Year and Design Day throughput, which are projected to increase at average annual rates of about 3 percent, resulting in additional throughput of approximately 3 Bcf annually and 22,000 Dth on design day.

Table I-2: Northern Design Year and Design Day Throughput (Dth)

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	Company Use	Losses and Unbilled	Design Year Throughput	Design Day Throughput
2014/15	3,427,673	4,717,316	10,927,084	7,675	281,706	19,361,454	147,656
2015/16	3,529,064	4,814,657	11,054,783	7,675	287,422	19,693,601	150,050
2016/17	3,670,585	4,923,298	11,614,052	7,675	301,397	20,517,008	156,015
2017/18	3,828,674	5,027,661	12,265,011	7,675	317,084	21,446,105	162,759
2018/19	3,987,648	5,110,921	12,793,340	7,675	330,386	22,229,970	168,438
2019/20	4,118,394	5,147,115	12,832,082	7,675	333,997	22,439,263	169,945
CAGR	3.7%	1.8%	3.3%	0.0%	3.5%	3.0%	2.9%

As discussed in this IRP, the transportation service program operated by the Company allows commercial and industrial (C&I) customers to purchase natural gas supplies directly from retail marketers. In recent years, transportation volumes have exceeded sales of gas to customers by the Company. That is, the majority of all gas distributed to customers on the Company's system was sold by parties other than Northern. Other things being equal, Northern is indifferent with regard to whether gas sold to customers is acquired directly or by retail marketers as Northern does not earn a return on gas sales. However, under current program rules, the service decision by the customer (i.e., sales or transportation and any migration to or from) may impact the planning load volume and, therefore, Northern resource decisions (e.g., resource levels and asset types).

Since Northern operates an unbundled system, the Company's planning load includes only the demand of customers for whom the Company has planning authority. The Company's planning load includes: (i) the natural gas demand of customers who continue to take supply from the Company; and (ii) those customers who receive natural gas supply from competitive suppliers but are assigned capacity pursuant to Northern's tariffs. Therefore, Northern is not required to hold capacity for a significant and growing segment of customers. The resource requirement for customer demands not included in planning load is managed by the customer and their marketer.

In order accommodate the uncertainty in planning obligations the transportation program rules create, Northern defined its Long-Term Planning Load to include only those customer loads that would definitely receive sales service or be subject to capacity assignment under the Deliver Service Tariffs. In addition, Northern defined additional planning load cases. The Short-Term Planning Load assumes that C&I customers choose between sales service and transportation service, and are classified as capacity assigned or exempt from capacity assignment, in proportion to current levels. Lastly, for illustrative purposes, Northern included an Alternative Planning Load case, which reflects its proposal in Maine Public Utilities Commission Docket 2014-132. Table I-3 compares the planning load forecast under design weather conditions over the planning period for these different versions of Planning Load. Northern designs its long-term portfolio to meet Long-Term Planning Load.

Table I-3: Design Condition Planning Load Comparisons (Dth)

	Design Year			Design Day		
Split Year	Long-Term Planning Load	Short-Term Planning Load	Alternative Planning Load	Long-Term Planning Load	Short-Term Planning Load	Alternative Planning Load
2014/15	11,476,911	12,874,107	14,462,023	96,572	106,155	124,155
2015/16	11,580,067	13,132,597	14,727,233	97,321	108,083	126,213
2016/17	11,723,968	13,619,291	15,350,728	98,374	111,882	131,179
2017/18	11,884,705	14,155,647	16,053,260	99,552	116,098	136,794
2018/19	12,046,344	14,620,572	16,654,239	100,738	119,724	141,559
2019/20	12,179,304	14,807,772	16,841,964	101,713	121,091	142,954
CAGR	1.2%	2.8%	3.1%	1.0%	2.7%	2.9%

In terms of existing supply-side resources, Northern has the ability to source supply through three major pipelines, including Tennessee Gas Pipeline L.L.C. ("Tennessee" or "TGP"), Portland Natural Gas Transmission System ("PNGTS"), and Maritimes & Northeast Pipeline, L.L.C. ("M&NP"), each of which provides supplies that can be delivered to Northern directly or via Granite State Gas Transmission, Inc. ("Granite" or "GSGT"). Major supply sources connected to Tennessee include the Gulf of Mexico supply basin and the Appalachian supply basin (specifically, Marcellus and Utica Shale). The PNGTS pipeline connects to the TransCanada PipeLines Limited ("TransCanada" or TCPL") Canadian Mainline/Trans-Québec and Maritimes Pipeline ("TQM"), which accesses natural gas supply from the Western Canadian Sedimentary Basin ("WCSB") and the Chicago/Dawn Hubs. The M&NP system has historically accessed natural gas supplies from Atlantic Canada (e.g., Sable Island) and imported LNG (i.e., Canaport LNG). The Company also utilizes service on Algonquin Gas Transmission, LLC ("Algonquin" or "AGT"). Similar to Tennessee, the Algonquin system, in conjunction with Texas Eastern Transmission, LP ("Texas Eastern" or "TETCO"), both owned by Spectra Energy,[1] has access to various natural gas supply basins, including the Gulf of Mexico and Appalachian regions. Given the significant impact of the Marcellus and Utica Shale basins on the natural gas markets and the geographical location of these basins (i.e., in the market area), the IRP provides a detailed discussion of this development. Finally, Northern utilizes on-system resources (e.g., LNG facilities).

In the IRP, Northern compares the Long-Term Planning Load forecast under design weather conditions to the supplies available from its portfolio of long-term natural gas supply resources to identify incremental resource requirements, and inform capacity renewal decisions. The comparison indicates that Northern's current resources are insufficient to meet planning load during the colder days of the year during the planning period of this IRP. Currently, Northern meets this supply need with supplies delivered by others to its system and therefore has significant reliance on delivered supplies.[2] Given the regional market conditions, such reliance will need to be addressed.

Notwithstanding very recent moderate price levels, over the past several years the natural gas prices for purchases transacted at the New England price indices have been well above previous observations. These high natural gas prices have impacted customers that purchase natural gas under delivered prices (i.e., New England price indices). Several new infrastructure projects have been proposed, and are in various stages of development, in response to these market conditions and in order to move the prolific supplies being produced in the Marcellus and Utica shale basins to market. The Company is reviewing each of the proposed projects and provides a summary description of these projects in the IRP.

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[1] Spectra Energy is also the majority owner and operator of the M&NP system.

[2] Delivered Supplies refer to natural gas supply that is delivered to Northern by third-parties under their own supply and capacity arrangements. As such, the Company does not exert any control over the supply or capacity used by the third party to provide the service. The price for the service is the New England market index price, which has been significantly more volatile than the indices used by Northern for supplies that feed its pipeline capacity contracts.

Given the forecast of planning load and the reliance on delivered supplies, the Company intends to renew all existing resources. These resources or contracts are typically "legacy contracts" (i.e., the costs of the underlying assets are heavily depreciated and therefore less expensive than the cost of new construction). Therefore, these legacy contracts are usually more cost effective capacity than incremental capacity. In addition, certain of the resources or contracts are also associated with natural gas storage that provides significant flexibility and price stability to the portfolio. Finally, certain of the resources and contracts are directly interconnected to Northern thus providing physical delivery of natural gas.

As discussed in this IRP, the Company utilizes both quantitative and qualitative approaches to review the different aspects of potential incremental natural gas supply projects. Quantitative tools are used to identify incremental resource needs, model the impact of adding various proxy resources to identify potential resource additions, and also to compare actual competing projects. As part of the qualitative (i.e., non-price) review, the Company evaluates the projects across various metrics, including upstream/downstream issues, project development risks, regulatory environment, and rate/toll flexibility and transparency. Ultimately, Northern relies primarily on qualitative criteria when making proposed resource decisions, so long as modeled costs of competing projects are reasonably comparable. Northern's primary reliance on qualitative assessment recognizes that price forecasts are subject to change in unpredictable ways and therefore reduces the possibility that major resource decisions are based primarily on price forecasts while ensuring that resource decisions are informed by appropriate selection criteria such as operational characteristics, added diversity or project risk – all of which cannot be adequately modeled.

Northern serves customers in both Maine and New Hampshire and therefore is regulated by both the Maine Public Utilities Commission and the New Hampshire Public Utilities Commission. Northern enters into transportation, storage and supply contracts on behalf of customers in order to provide reliable service at a reasonable cost. Northern expends extensive effort to assess the soundness of its decision making and provide sufficient supporting data and analysis that is adequate thus allowing decision makers in both states to understand the considerations evaluated and approve the cost consequences of any proposed contractual commitment.

While Northern leverages the demand of both Maine and New Hampshire customers to develop an integrated gas supply portfolio for all of its customers, there are certain state specific issues that will influence the portfolio such as capacity assignment requirements and any related impacts on cost allocation among customers in each state. These issues may impact the overall volume of the natural gas supply portfolio or which assets comprise the portfolio.

Lastly, Northern must ensure that new long-term resource decisions are determined by its regulators to promote the public interest, that Northern is granted approval to recover the costs associated with new long-term contracts and that its regulators will support Northern in the performance of its contractual obligations under new contracts.

In summary, the 2015 IRP is intended to communicate Northern's gas supply planning objective, describe the current market dynamics impacting long-term resource decisions; and the process used by the Company to forecast planning load, identify incremental resource needs and evaluate potential resource alternatives for possible addition to the portfolio.

II. Introduction

Northern Utilities, Inc. ("Northern" or the "Company"), a subsidiary of Unitil Corporation, is a local distribution company ("LDC") providing natural gas supply and distribution service to customers in the states of Maine and New Hampshire. Northern's predecessor companies date back over 160 years to the Portland Gas Light Company, which was formed in 1849. In 1979, Northern was acquired by Bay State Gas Company ("Bay State"), and in 1999, Northern and Bay State were acquired by NiSource, Inc. In 2008, Unitil Corporation purchased Northern from NiSource, Inc. As of year-end 2014, Northern provides service to approximately 31,075 customers in 23 communities in southern Maine and to approximately 31,150 customers in 22 communities in the seacoast region of New Hampshire. During the most recent split-year (i.e., November 1, 2013 to October 31, 2014), Northern had an annual throughput of 18,635,586 Dth, and a maximum daily sendout of 135,799 Dth on January 2, 2014.

Northern hereby submits its 2015 Integrated Resource Plan ("IRP"), which covers the five-year planning period from November 1, 2015 to October 31, 2020, as outlined and agreed to in the Stipulation and Settlement related to the Company's 2011 IRP (hereinafter referred to as the "2011 IRP Settlement")[3] and approved by the Public Utilities Commissions of Maine and New Hampshire (hereinafter referred to as the "MPUC" and "NHPUC", respectively).[4]

A. Structure of the Filing

Consistent with the planning processes and content requirements of the 2011 IRP Settlement, Northern's 2015 IRP filing is organized as follows:

- Section III, Regional Natural Gas Market Dynamics, discusses the New England market conditions and recent changes in natural gas demand and supply dynamics to provide context for the Company's resource planning process;
- Section IV, Demand Forecast, describes the methodology and results of Northern's forecast of natural gas demand over the five-year planning horizon (i.e., gas-years from 2015/16 to 2019/20), including development of the Customer Segment Demand models, Normal Year Throughput, and Design Year and Design Day Throughput;
- Section V, Planning Load Forecast, reviews the impacts of the Capacity Assignment provisions of the current Delivery Service Terms and Conditions tariffs on planning and presents the methodology and results of the Company's Long-Term Planning Load forecast;
- Section VI, Current Portfolio, describes the Company's existing long-term resource portfolio;
- Section VII, Resource Balance, provides a comparison of the existing long-term portfolio relative to the Company's Long-Term Planning Load forecast;

[3] Northern Utilities, Inc., 2011 Long-Range Integrated Resource Plan, Stipulation and Settlement, MPUC Docket No. 2011-00526 and NHPUC Docket No. DG 11-290, filed on December 24, 2013.

[4] Maine Public Utilities Commission, *Order Approving Stipulation*, Docket No. 2011-00526, February 3, 2014; and New Hampshire Public Utilities Commission, *Order Nisi Approving Stipulation and Settlement Agreement*, Order No. 25,641, Docket No. DG 11-290, March 26, 2014.

- Section VIII, Incremental Supply Resources, identifies reasonably available supply resource options that could meet identified portfolio needs;
- Section IX, Preferred Portfolio, describes the Company's approach to long-term portfolio planning and reviews the evaluation methods the Company uses to identify resource needs and compare competing long-term resources;
- Section X, Compliance with Directives, provides a detailed review of the directives outlined in the 2011 IRP Settlement and the actions taken by the Company to ensure compliance with those directives.

Additional supporting materials are provided in appendices.

III. Regional Market Overview

Section III discusses the New England market conditions and recent changes in natural gas demand and supply dynamics to provide context for the Company's resource planning process. The existing New England energy market conditions and the expected changes to regional natural gas demand and supply will likely continue to impact Northern's strategy to meet its Long-Term Planning Load requirements over the planning period. Specifically, certain of the existing gas supplies (e.g., Sable Island and imported LNG) that have been available for purchase at Northern's system are either in decline or have access to other markets. In addition, the increasing natural gas demand in the New England region and the pipeline capacity constraints from the Mid-Atlantic production area to the New England markets continue to impact the natural gas prices and associated volatility faced by Northern.

The remainder of this section is organized as follows:

Part A, Overview of New England and Atlantic Canada Region, provides an overview of the existing natural gas infrastructure and supply resources used to serve Northern, in particular, and the New England and Atlantic Canada region, in general;

Part B, Atlantic Canada Supply and Demand, discusses the natural gas supply and demand issues in Atlantic Canada that have impacted the New England markets;

Part C, TransCanada Regulatory Developments, provides an overview of the TransCanada regulatory proceedings;

Part D, Imported LNG, reviews the LNG activity in the New England region, and discusses the impact of alternative LNG markets on New England LNG supply;

Part E, Mid-Atlantic Natural Gas Production, discusses the natural gas supply developments with respect to the Marcellus and Utica Shale gas basins, and summarizes certain natural gas pipeline infrastructure developments in the Northeast U.S.;

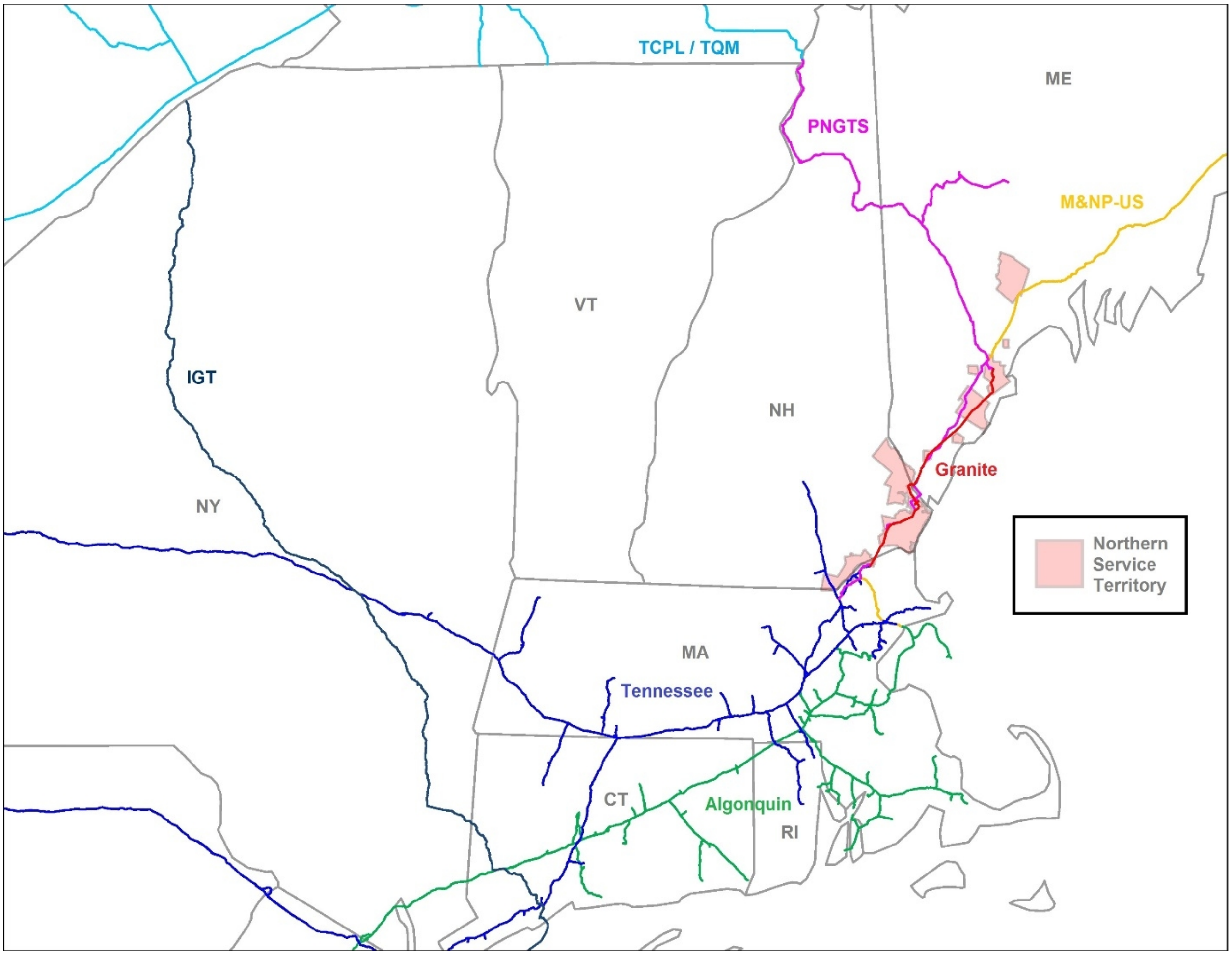
Part F, Regional Natural Gas Demand, provides an overview of the current natural gas markets in New England, and discusses certain natural gas demand drivers in New England; and

Part G, Natural Gas Price Analysis, reviews the regional natural gas prices and the impact of energy market conditions on New England natural gas prices and basis values.

A. Overview of New England and Atlantic Canada Region

As discussed in Section II, Northern currently provides service to customers in 23 communities in southern Maine and 22 communities in the seacoast region of New Hampshire. Figure III-1 below illustrates Northern's service territory relative to the regional natural gas pipeline infrastructure.

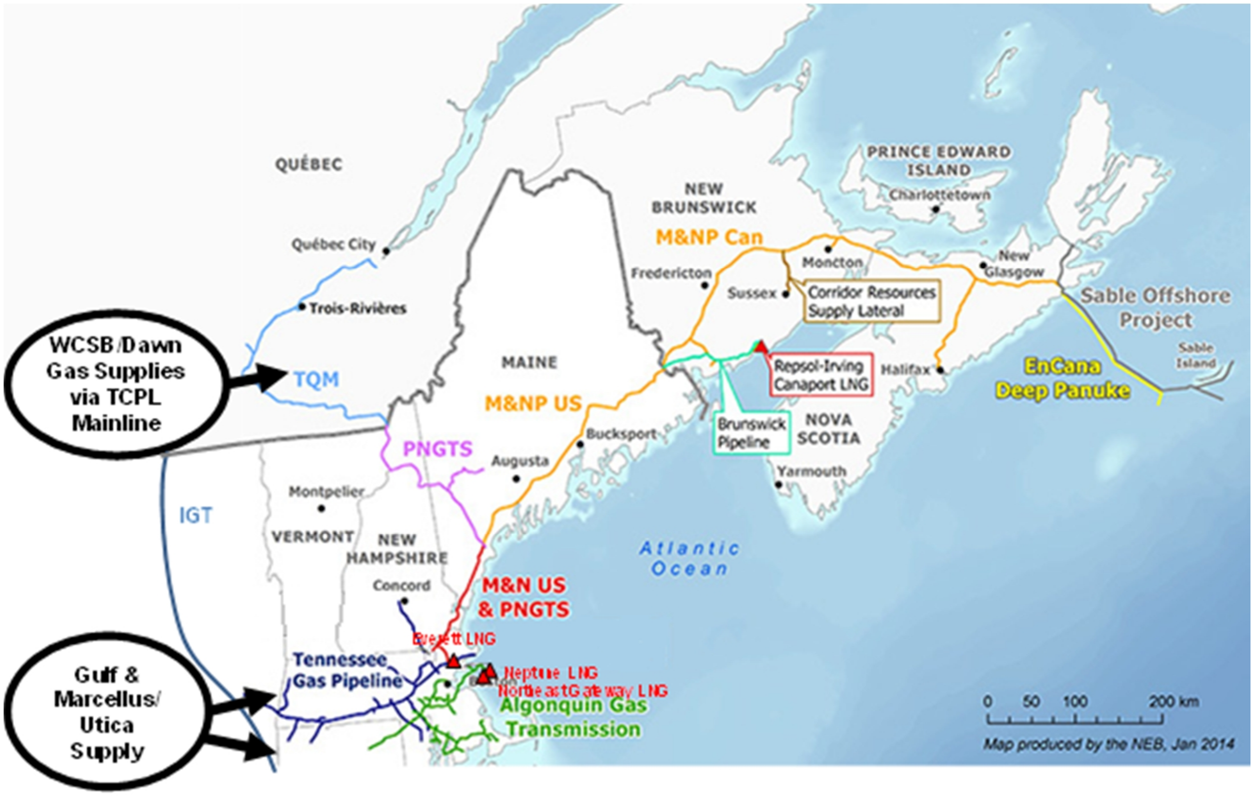
Figure III-1: Northern Service Territory and Regional Pipeline Infrastructure[5]



As shown in Figure III-1 above, Northern's service territory in Maine and New Hampshire is at the "end of the line" of three major interstate pipelines in New England; specifically, Tennessee, PNGTS, and M&NP, each of which delivers to Northern directly or via Granite. As discussed in Section VI of this IRP, Northern currently has capacity contracts on these pipelines, as well as on Algonquin, which provides the Company with access to various natural gas supply sources. Figure III-2 below illustrates certain of the natural gas supply sources that are available to the New England region.

5 Source: Sussex Economic Advisors, LLC ("Sussex") as obtained from SNL Financial and modified by Sussex.

Figure III-2: Existing New England/Atlantic Canada Natural Gas Infrastructure[6]



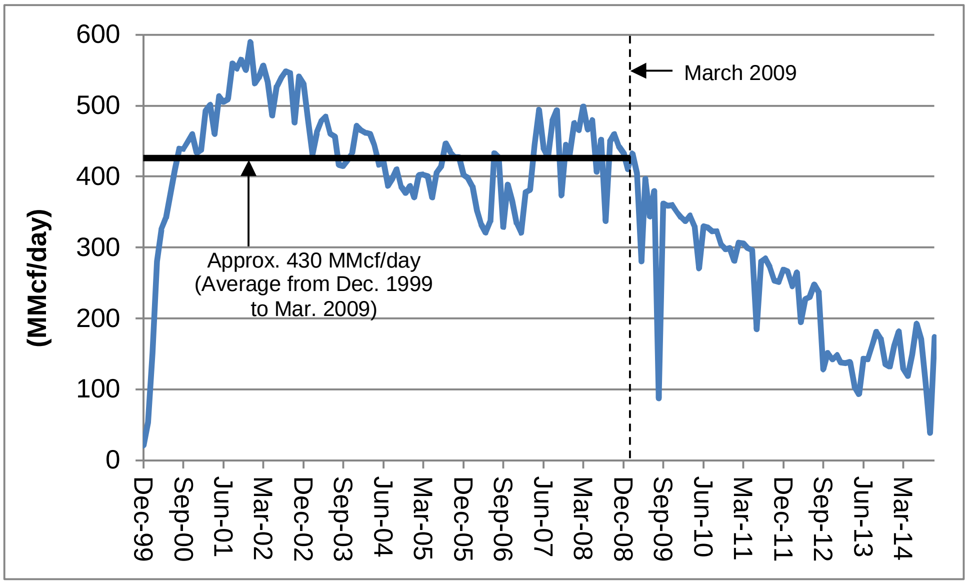
As illustrated by Figure III-2, the New England region has access to a variety of natural gas supplies, including: (i) WCSB, Chicago Hub, Michigan Storage, and Dawn Hub gas supplies via the TCPL Mainline/TQM, and Iroquois Gas Transmission System, LP ("Iroquois" or "IGT")/PNGTS; (ii) natural gas supplies from the Atlantic Canada region; (iii) imported LNG via four on- and off-shore import facilities; and (iv) Gulf Coast, Pennsylvania Storage, and Marcellus/Utica gas supplies via major interstate natural gas pipelines (e.g., Tennessee and Algonquin).

B. Atlantic Canada Supply and Demand

One of the natural gas supply resources for the Atlantic Canada and New England region is natural gas production from the Sable Offshore Energy Project ("SOEP"), located offshore of Nova Scotia. Figure III-3 below illustrates the average daily SOEP production since its inception in December 1999 through October 2014.

6 Source: National Energy Board, "Canadian Energy Dynamics 2013", March 2014, at 8 [modified by Sussex].

Figure III-3: SOEP Natural Gas Production[7]



As shown in Figure III-3, gas supplies from SOEP provided New England market participants with a reliable resource option from 2000 to March 2009 as production was consistently at or above 400 MMcf/day. This volume level not only met the Atlantic Canada average natural gas demand over the 2000 to 2008 time period of approximately 150 MMcf/day,[8] but also provided export volume of approximately 250 MMcf/day for New England markets. However, the production from this basin has significantly decreased over the past several years. Specifically, natural gas production from SOEP has declined from approximately 600 MMcf/day in December 2001 to less than 200 MMcf/day in October 2014.[9] Thus, the current SOEP production level of approximately 140 MMcf/day in 2014 (i.e., the 2014 arithmetic average through October 2014) is not sufficient to meet Atlantic Canada demand (i.e., over 200 MMcf/day[10]), which may result in little, if any, volume available to be exported to New England.

Although SOEP was initially expected to produce natural gas for 25 years (i.e., an end date of 2024 based on the 1999 commence date),[11] the steep decline in SOEP production since 2009 has led to

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7 Source: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports, accessed on December 12, 2014.

8 Simple average of end-use demand in Atlantic Canada from 2000 to 2008. As discussed later in this section, end-use natural gas demand in Atlantic Canada over the 2000 to 2008 time period actually increased from 34 MMcf/day to 252 MMcf/day, respectively. See, National Energy Board, "Canada's Energy Future 2013 - Energy Supply and Demand Projections to 2035 – Appendices", Reference Case, November 2013.

9 Source: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports, accessed on December 12, 2014.

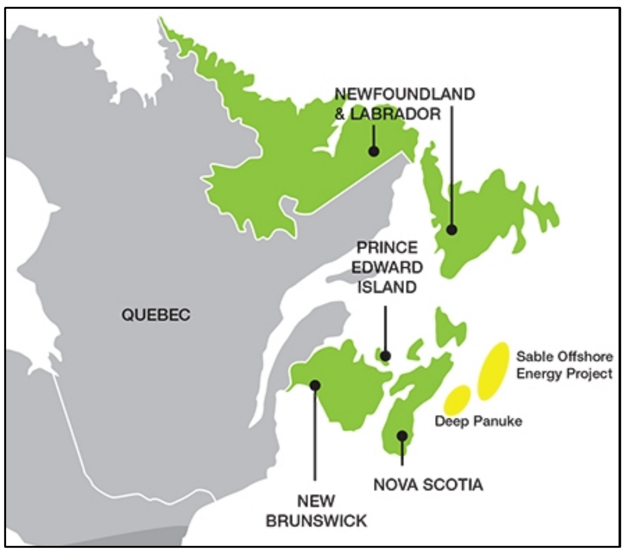
10 End-use natural gas demand in Atlantic Canada for 2014 is estimated to be approximately 220 MMcf/day. See, National Energy Board, "Canada's Energy Future 2013 - Energy Supply and Demand Projections to 2035 – Appendices", Reference Case, November 2013.

11 See, Sable Offshore Energy Project, Development Plan Application, at 1-3.

uncertainty regarding the future level of production. ExxonMobil Canada Properties Ltd. ("ExxonMobil"), the majority owner and operator of SOEP,[12] has recently stated that there is no firm end date set for SOEP; however, in February 2014, ExxonMobil issued a notice for expressions of interest for abandonment work to commence in 2015.[13] In addition, in a recent regulatory filing, Nova Scotia Power Inc. ("NS Power") has indicated that it expects SOEP to cease operation in October 2016 based on recent SOEP production trends.[14] Finally, several other sources, including the National Energy Board of Canada ("NEB") and Atlantica Centre for Energy, have also indicated a pre-mature end date for SOEP between 2017 and 2019.[15]

Since the summer of 2013, new natural gas supplies from the Deep Panuke Offshore Gas Development Project ("Deep Panuke") have come on-line to augment the SOEP production. Similar to SOEP, the Deep Panuke facilities are located offshore of Nova Scotia (see Figure III-4 below).

Figure III-4: Location of Offshore Nova Scotia Facilities[16]



Specifically, production from Deep Panuke commenced in August 2013, and averaged approximately 240 MMcf/day from January 2014 to September 2014.[17,18] Figure III-5 below illustrates

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12 ExxonMobil owns the majority interest (50.8%) in SOEP; the remaining owners include: Shell Canada Limited (31.3%), Imperial Oil Resources (9%), Pengrowth Corporation (8.4%), and Mosbacher Operating Ltd. (0.5%).

13 See, The Chronicle Herald, "NSP may be right about Sable gas cutoff", August 21, 2014; and The Chronicle Herald, "ExxonMobil preparing for SOEP abandonment", February 28, 2014.

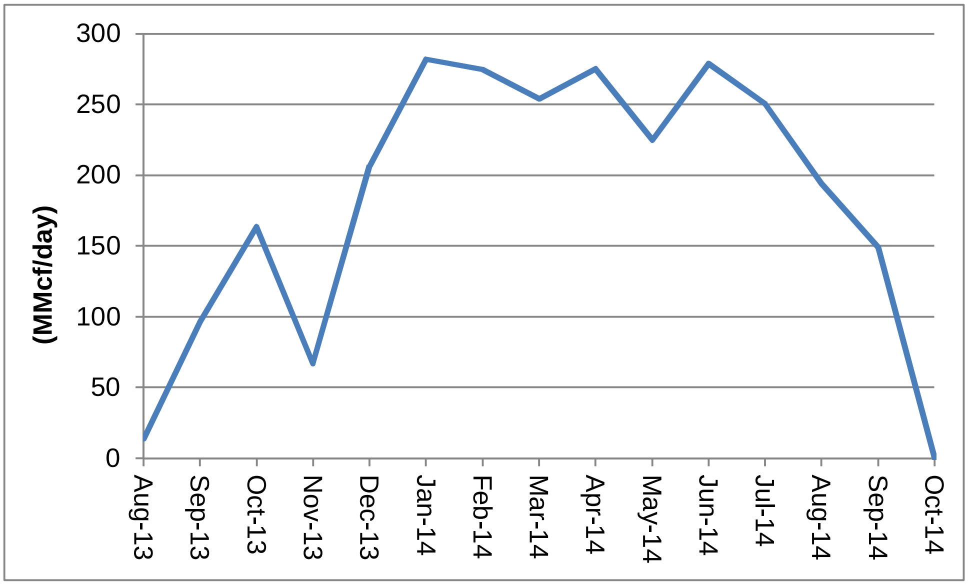
14 See, Nova Scotia Power Inc., *In the Matter of the 2014 Fuel Adjustment Mechanism (FAM) Audit (M06290)*, *NS Power Reply Evidence*, Nova Scotia Utility and Review Board, August 18, 2014, at 51-52.

15 See, National Energy Board, "Canada's Energy Future 2013 - Energy Supply and Demand Projections to 2035 – Appendices", Reference Case, November 2013; Atlantica Centre for Energy, "The Future of Natural Gas in Our Region: Impacts, Challenges and Opportunities", October 2012, at 5; Government of New Brunswick, "The New Brunswick Oil and Natural Gas Blueprint", May 2013, at 10; and Nova Scotia Department of Energy, "The Future of Natural Gas Supply for Nova Scotia", prepared by ICF Consulting Canada, Inc., March 28, 2013, at 21.

16 Source: Canadian Association of Petroleum Producers [modified by Sussex].

the average daily gas production from Deep Panuke through October 2014. Specifically, Deep Panuke natural gas production averaged approximately 250 MMcf/day during the January 2014 through July 2014 time period.

Figure III-5: Deep Panuke Natural Gas Production[19]



As outlined in the Deep Panuke development plan, natural gas production from Deep Panuke is expected to continue for 8 to 17.5 years, with a mean production life of 13 years.[20] Thus, Deep Panuke supplies have and will continue to augment the decrease in SOEP production; however, over the long term, this supply resource is expected to have a declining production curve similar to SOEP. Specifically, as noted in a study prepared for the Nova Scotia Department of Energy:

> *"Deep Panuke, is projected to come online in mid-2013, with peak production volumes of 300 MMcfd by 2014-15. After 2015, production from Deep Panuke is projected to decline, reaching 90 MMcfd by 2020 and less than 20 MMcfd by 2035."*[21]

Recently, there have been concerns regarding the production life and duration of production levels from Deep Panuke as a result of water in the gas stream. The levels of water were higher than anticipated, and led to an extended shut down for maintenance of the production field. Deep Panuke

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17 Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, accessed on December 12, 2014.

18 As discussed later, Deep Panuke was shut down for extended maintenance in late September 2014 through mid-November 2014. See, CBC News, "Deep Panuke back in production after water forced shutdown", November 17, 2014.

19 Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, accessed on December 12, 2014.

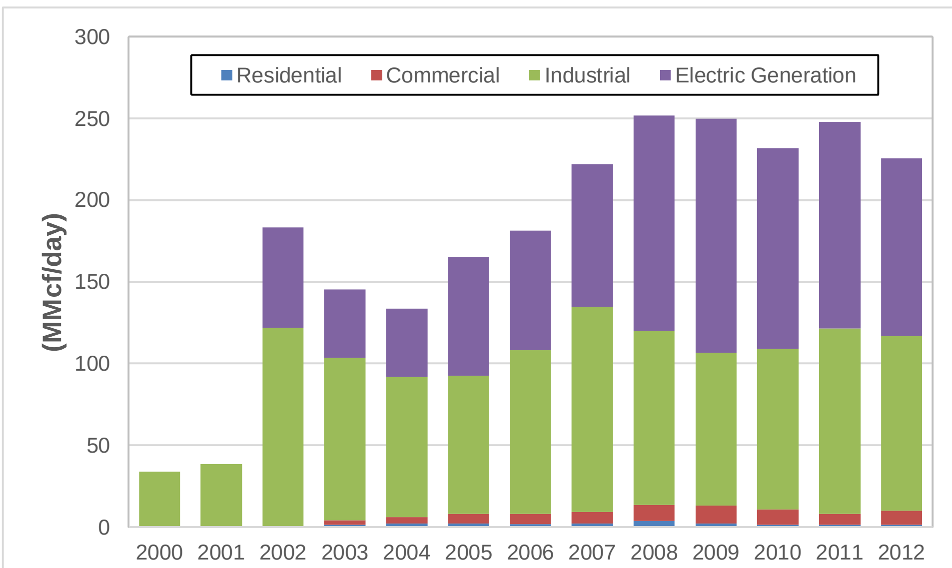
20 See, EnCana Corporation, "Deep Panuke Offshore Gas Development, Development Plan", Volume 2, November 2006, at 1-11.

21 Nova Scotia Department of Energy, "The Future of Natural Gas Supply for Nova Scotia", prepared by ICF Consulting Canada, Inc., March 28, 2013, at 35.

was back on-line in November 2014, however, production levels are expected to be between 140 MMcf/day to 180 MMcf/day, which is well below the total capacity level of 300 MMcf/day.[22]

In addition to uncertainty regarding the production life of Atlantic Canada supplies (i.e., natural gas production from SOEP and Deep Panuke), growth in natural gas demand in the Atlantic Canada region is increasing, which may result in less natural gas supply available for delivery to New England markets. Specifically, natural gas demand in Atlantic Canada has increased by nearly six-fold from approximately 34 MMcf/day to 226 MMcf/day over the 2000 to 2012 time period.[23] The power generation and industrial segments account for the majority of the natural gas demand in Atlantic Canada (i.e., accounting for 48% and 47% of total end-use demand in 2012, respectively); however, LDC demand (i.e., Heritage Gas and Enbridge Gas New Brunswick) is also increasing. Specifically, the natural gas demand by the residential and commercial sectors increased from zero in 2000 to approximately 4 MMcf/day in 2003 to nearly 10 MMcf/day in 2012. Figure III-6 below illustrates the historical average daily demand by sector for the Atlantic Canada provinces.

Figure III-6: Atlantic Canada – End-Use Natural Gas Demand[24]



The demand for natural gas in Atlantic Canada is forecasted to continue to increase to nearly 300 MMcf/day by 2035.[25] This increase in natural gas demand is driven by the power generation and LDC sectors, as the demand by the industrial sector is forecasted to decrease over the 2012 to 2035 time

22 See, The Chronicle Herald, "Water delays maintenance of Deep Panuke", November 13, 2014; and CBC News, "Deep Panuke back in production after water forced shutdown", November 17, 2014.

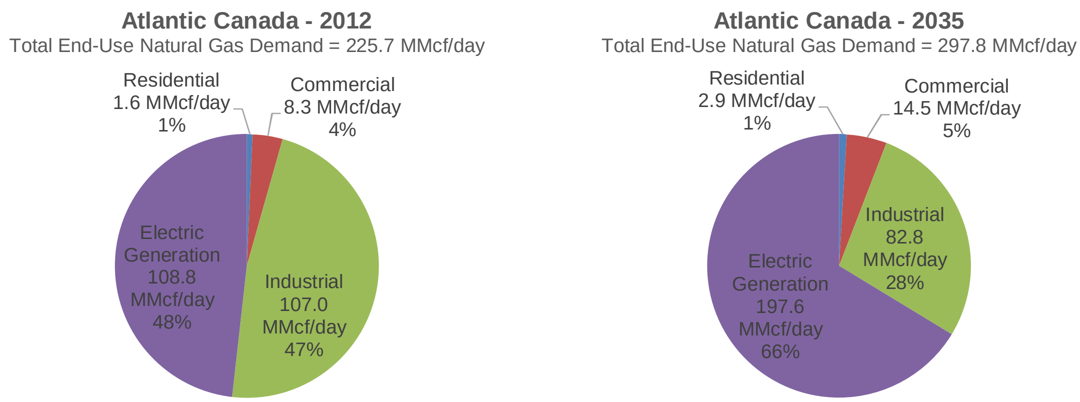
23 See, National Energy Board, "Canada's Energy Future 2013 - Energy Supply and Demand Projections to 2035 – Appendices", Reference Case, November 2013.

24 Ibid.

25 Ibid.

period. As shown in Figure III-7 below, the natural gas demand by the largest sector (i.e., the power generation sector) increases from approximately 110 MMcf/day in 2012 to 200 MMcf/day in 2035, while the residential and commercial sectors increase from approximately 10 MMcf/day in 2012 to 17 MMcf/day in 2035.[26]

Figure III-7: Atlantic Canada – Forecasted End-Use Natural Gas Demand[27]



Due to the decreased natural gas production from Sable Island and the increasing Atlantic Canada demand for natural gas, ICF Consulting Canada Inc. had the following recommendation in a March 2013 report prepared for the Nova Scotia Department of Energy: "there is a strong argument for Maritimes Canada consumers to contract for firm pipeline capacity on one of the proposed pipeline expansions into New England that would allow shippers to buy gas at one of the Marcellus basin hubs to an interconnection with M&NP. This would ensure a reliable source of gas as well as avoid the price volatility in New England."[28]

Therefore, although New England has historically relied on natural gas supplies from Atlantic Canada, the recent supply and demand trends in the Atlantic Canada region will impact the future reliability, availability, and pricing of natural gas supplies to New England markets over the longer term. Specifically, the natural gas production from SOEP has dramatically declined since 2009, and although production from Deep Panuke is expected to provide short term relief, it is not likely to be a long term solution. The uncertainty regarding the production life of both SOEP and Deep Panuke, coupled with the growth in natural gas demand within the Atlantic Canada region, will potentially result in less natural gas supplies available for delivery to New England markets.

C. TransCanada Regulatory Developments

Although Northern actively participates in various Federal Energy Regulatory Commission ("FERC") and NEB proceedings, the current TransCanada filings at the NEB are of particular significance.

[26] Ibid.

[27] Ibid.

[28] ICF Consulting Canada, Inc., "The Future of Natural Gas Supply for Nova Scotia", March 28, 2013.

Specifically, TransCanada has three major applications that will likely impact the cost structure, service offerings, and tolls associated with natural gas supplies transported on the TCPL Mainline. The first TransCanada application reviewed is the TCPL Mainline Settlement, which was approved by the NEB on December 18, 2014. Next, the Company discusses the Energy East Pipeline project, which may impact the existing TCPL Mainline facilities in the Prairies, Northern Ontario and the Eastern Ontario Triangle. Finally, Northern reviews the Eastern Mainline Project that consists of a potential expansion of certain TCPL Mainline facilities in Ontario and Quebec. Each of the TransCanada filings is discussed in some detail below.

1. TCPL Mainline Settlement

Recently, TransCanada received from the NEB a Reasons for Decision ("Decision") regarding the TCPL Mainline Settlement application. In general, the NEB Decision provides more rate/toll certainty for the TCPL Mainline shippers; however, certain issues could influence the level of the rates/tolls. Specifically, the NEB Decision allows TransCanada to offer known rates/tolls on the TCPL Mainline over the next three years (i.e., 2015 through 2017) which will also include various surcharges. For the following two years (i.e., 2018 through 2019), TransCanada may adjust the level of the rates/tolls on the TCPL Mainline depending on certain underlying revenue and billing determinant assumptions.

Over the longer term (i.e., 2020 and beyond), the level of the rates/tolls on the TCPL Mainline will be based on a segmented cost of service, where the rates/tolls for three geographic regions on the TCPL Mainline (i.e., the Prairies, Northern Ontario Line and the Eastern Ontario Triangle) are based on the revenue requirement and billing determinants for each specific region.

Although the NEB Decision provides TransCanada some rate/toll certainty, there are variables that could impact the TCPL Mainline rates/tolls, including the values for two surcharges (i.e., the Long Term Adjustment Account and Bridging Amortization Account). The Long Term Adjustment Account will reflect, among other items, the variances between forecasted and actual revenue over the 2015 through 2020 time period; while the Bridging Amortization Account includes the difference between the revenue provided by the proposed fixed tolls and the TCPL required revenue.

In addition to the rate/toll issues, the NEB Decision also addressed the proposed expansion of the TCPL Mainline. The NEB Decision, with respect to the proposed TCPL Mainline expansion, will likely influence Northern's existing capacity contracts on the TCPL Mainline. Specifically, prior to an expansion of the TCPL Mainline that exceeds $20 million, TransCanada can require existing firm shippers to extend the expiration of their contracts so that the new termination date is five years after the in-service date of the proposed expansion. The Company expects the pending TCPL Mainline open season (i.e., the

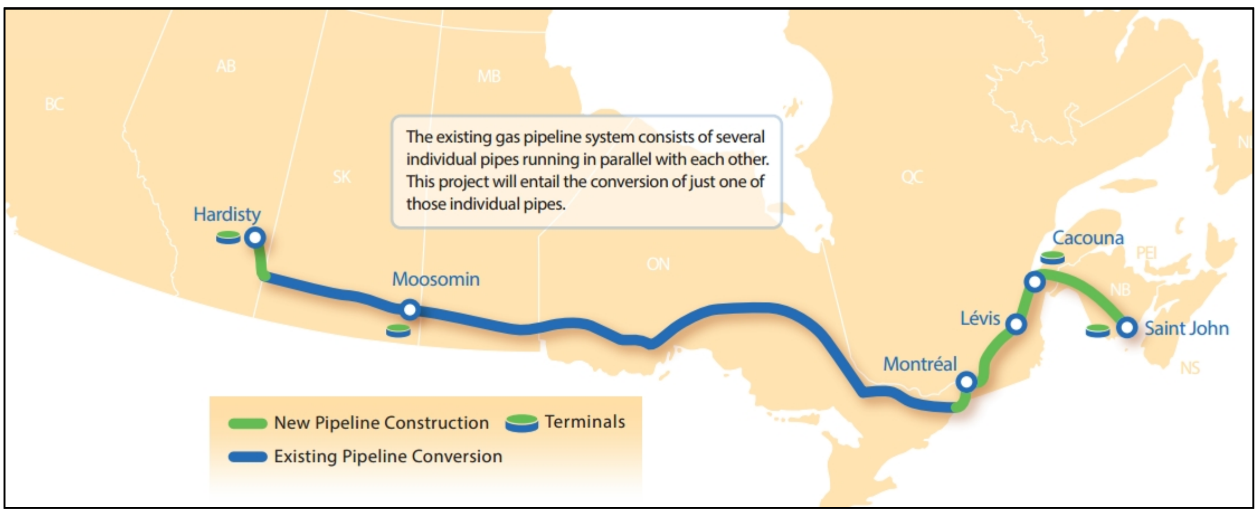
2017 new capacity open season is scheduled to close on January 30, 2015),[29] will meet the $20 million threshold and, therefore, will likely require Northern to extend its existing TCPL Mainline contracts.

Finally, the NEB Decision was issued on December 18, 2014 with a requirement for TransCanada to submit a compliance filing by March 31, 2015. As a result, the actual tariff, services and tolls are subject to TransCanada's submission of that compliance filing and the acceptance by the NEB of the TransCanada submittal. The Company will continue to follow this proceeding and provide updated information, as necessary.

2. Energy East Pipeline

The proposed Energy East Pipeline ("Energy East") will transport approximately 1.1 million barrels of crude oil per day from multiple receipt points in western Canada to refineries in eastern Canada. As illustrated in Figure III-22, as part of the Energy East project, TransCanada plans to convert approximately 1,864 miles of the existing TCPL Mainline from the delivery of natural gas to the delivery of oil. In addition, the Energy East project will consist of the construction of new pipeline sections in six Canadian provinces, as well as associated facilities, pump stations and tank terminals.[30]

Figure III-22: Energy East – Proposed Route[31]



The estimated capital cost for the Energy East project is approximately $12 billion, excluding the transfer value associated with the conversion of certain TCPL Mainline facilities to transport oil.[32] The Energy East project is supported by firm 20-year shipping contracts for 905,000 barrels per day.[33]

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29 See, TransCanada PipeLines Limited, "TransCanada's Firm Transportation New Capacity Open Season", December 12, 2014.

30 See, TransCanada Corporation, "$12-Billion Energy East Pipeline Project Takes Important Step Forward With NEB Application Filing", October 30, 2014; and Energy East Pipeline website (http://www.energyeastpipeline.com).

31 Source: Energy East Pipeline website (http://www.energyeastpipeline.com).

32 See, TransCanada Corporation, "$12-Billion Energy East Pipeline Project Takes Important Step Forward With NEB Application Filing", October 30, 2014

TransCanada filed its formal application for the Energy East project with the NEB in October 2014. The formal application seeks approval for: (i) the sale of pipeline assets from TCPL Mainline to Energy East; (ii) the conversion of gas pipeline to oil service; (iii) the construction of new oil pipeline facilities; (iv) a certificate to own and operate the new and converted facilities; and (v) approval of the proposed tariff and tolling methodology. TransCanada expects to receive final approval from the NEB in late 2015, and plans to place the Energy East project in-service by late 2018.[34]

The TransCanada application for the Energy East project submitted to the NEB has resulted in significant opposition from various energy market participants, including: Union Gas Limited ("Union Gas"), Enbridge Gas Distribution Inc., Gaz Métro Limited Partnership, and Alberta Northeast Gas Limited. Although there are several areas of contention, the most significant centers around the conversion of certain TPL Mainline assets in Ontario to oil service from natural gas service.

3. Eastern Mainline Project

TransCanada has proposed to construct the Eastern Mainline Project to serve the firm transportation requirements of natural gas shippers in the Eastern Triangle after the conversion of a portion of the TCPL Mainline from natural gas delivery service to oil service as part of the Energy East project discussed above.[35] The proposed Eastern Mainline Project consists of approximately 150 miles of new 36-inch diameter natural gas pipeline and related facilities that will be integrated into the TCPL Mainline to serve the Ontario and Québec provinces as shown in Figure III-23 below.[36]

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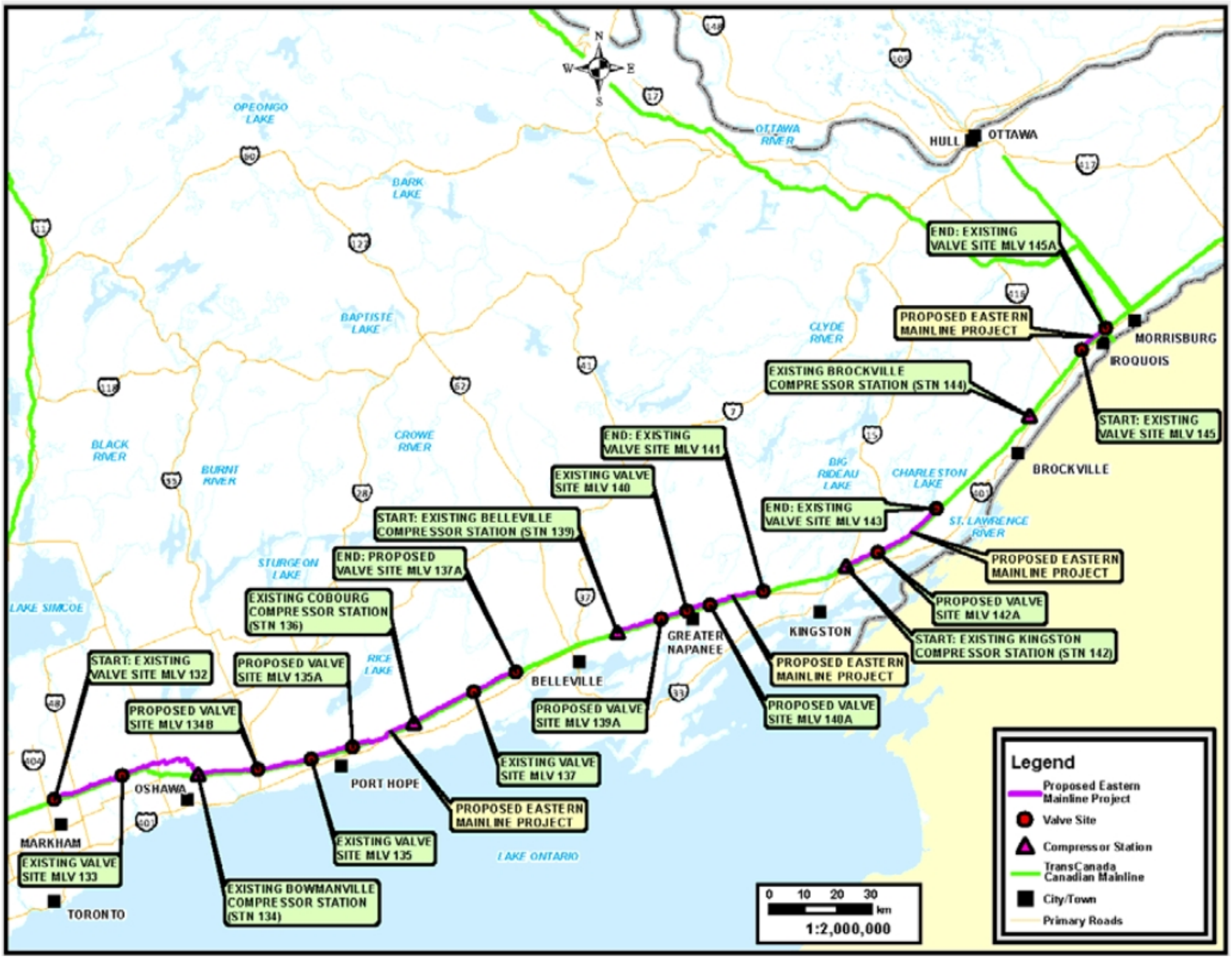
[33] See, Energy East Pipeline Ltd., Energy East Project, Volume 1: Application and Project Overview, Section 2: Project Overview, October 30, 2014, at 2-7.

[34] See, TransCanada Corporation, "$12-Billion Energy East Pipeline Project Takes Important Step Forward With NEB Application Filing", October 30, 2014; and Energy East Pipeline website (http://www.energyeastpipeline.com).

[35] See, TransCanada PipeLines Limited, Eastern Mainline Project Application, Section 1, October 30, 2014.

[36] See, Eastern Mainline Project website (http://easternmainline.com).

Figure III-23: Eastern Mainline Project[37]



The estimated capital costs for the Eastern Mainline Project is approximately $1.5 billion. Pending NEB approval, TransCanada plans to commence construction on the Eastern Mainline Project in the spring of 2016 and place the facilities in-service prior to the proposed asset transfer close date of March 31, 2017.[38]

D. Imported LNG

In addition to natural gas supplies from Atlantic Canada, the New England region has historically relied on imported LNG to serve regional demand requirements. As noted by the Northeast Gas Association ("NGA"), LNG has provided approximately 30% of the peak day requirements in New England.[39]

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37 Source: TransCanada PipeLines Limited, Eastern Mainline Project Application, Section 1, October 30, 2014, at 1-5.

38 See, TransCanada PipeLines Limited, Eastern Mainline Project Application, Section 1, October 30, 2014; and Eastern Mainline Project website (http://easternmainline.com).

39 See, Northeast Gas Association, "Statistical Guide to the Northeast U.S. Natural Gas Industry 2014", December 2014, at 3.

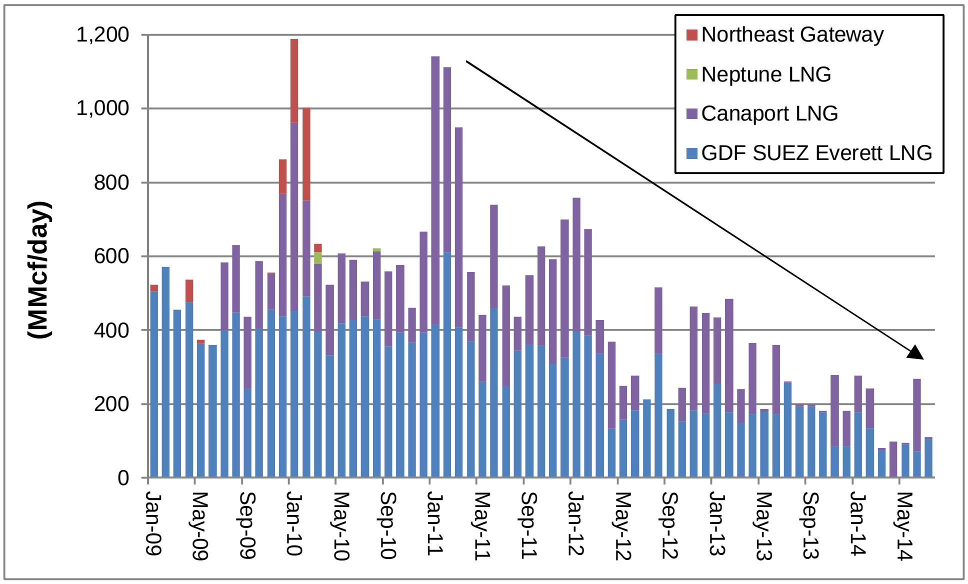
The LNG infrastructure serving the New England market consists of both LNG peak-shaving facilities and LNG import terminals. Specifically, there are 45 LDC-owned LNG satellite tanks and peak-shaving facilities located in New England with a total storage capacity of approximately 16 Bcf and vaporization capacity of approximately 1.4 Bcf/day.[40] In addition, there are four LNG importation terminals that provide service to the New England region, specifically:

- GDF SUEZ Gas NA's ("GDF SUEZ") on-shore LNG facility in Everett, Massachusetts;
- GDF SUEZ's Neptune LNG terminal located off-shore of Gloucester, Massachusetts;
- Excelerate Energy's Northeast Gateway facility located off-shore of Cape Ann, Massachusetts; and
- The Canaport LNG terminal in St. John, New Brunswick, which is owned by Repsol (75%) and Irving Oil (25%).

As illustrated in Figure III-8 below, the two off-shore facilities (i.e., the Northeast Gateway and Neptune LNG terminals) as of November, 2014 have not received any LNG cargoes since commencing service in 2009 and 2010, respectively.[41] The utilization of the two on-shore facilities (i.e., the GDF SUEZ Everett LNG and Canaport LNG facilities) has declined significantly; pecifically, the GDF SUEZ Everett LNG facility has experienced a steady decrease in utilization over the past six years from an average monthly import volume of 13 Bcf (i.e., approximately 430 MMcf/day) in 2009 to an average monthly import volume of less than 3 Bcf (i.e., less than 100 MMcf/day) in 2014.[42] Similarly, the Canaport LNG terminal has declined from a peak monthly import volume of approximately 23 Bcf (i.e., approximately 700 MMcf/day) in January 2011 to a peak monthly import volume of approximately 6 Bcf (i.e., approximately 200 MMcf/day) in June 2014.[43]

40 Ibid.
41 Source: U.S. Department of Energy, LNG Annual and Monthly Reports, accessed on December 12, 2014.
42 Ibid.
43 Source: National Energy Board, LNG - Shipment Details, assessed on December 12, 2014.

Figure III-8: Imported LNG Volumes[44]

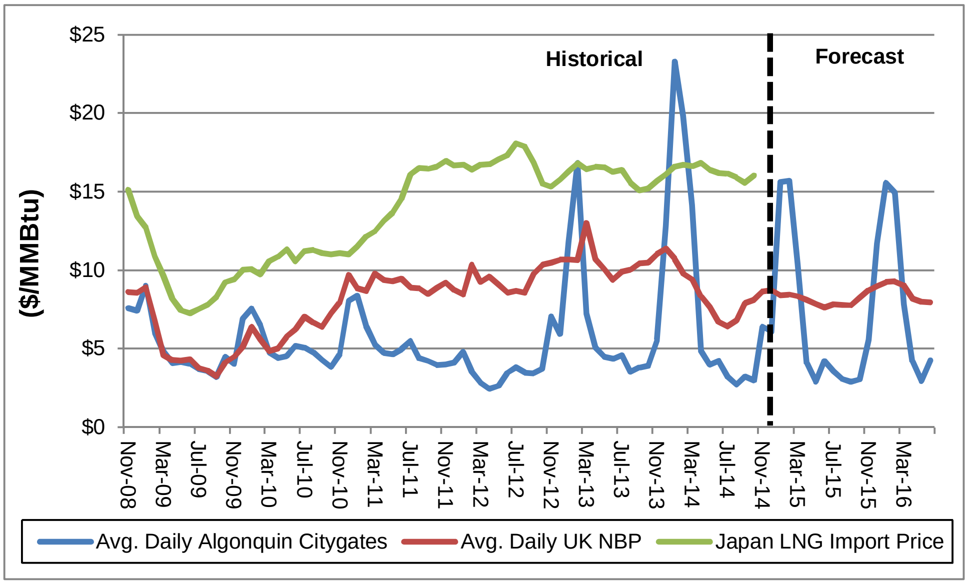


As shown in Figure III-8 above, the total average monthly LNG import volume declined from approximately 37 Bcf (i.e., approximately 1,200 MMcf/day) in January 2010 and 35 Bcf (i.e., approximately 1,100 MMcf/day) in January 2011 to 8 Bcf (i.e., approximately 280 MMcf/day) in November 2013 (i.e., a decline of over 75%).

The reduction in LNG import volumes is likely attributed to several factors, including the price signals at other markets accessed by the LNG suppliers. As shown in Figure III-9 below, the United Kingdom natural gas prices (i.e., the National Balancing Point ("UK NBP")) and Asian LNG prices have historically been at a premium to New England natural gas prices (as represented by the Algonquin Citygates price index).

[44] Sources: U.S. Department of Energy, LNG Annual and Monthly Reports, accessed on December 12, 2014; and National Energy Board, LNG - Shipment Details, assessed on December 12, 2014.

Figure III-9: LNG Market Signals[45]



Although the forward prices for the Algonquin City-gate index are expected to be greater than the UK NBP during the peak winter months (i.e., December through February), the duration of that peak season price may or may not attract LNG shipments to New England. This issue was discussed by the FERC prior to the winter of 2013/2014, "LNG is likely to remain in short supply this winter with price spikes in New England not sustained long enough to incentivize LNG cargos."[46] In addition the NGA has also stated "LNG imports to both [the GDF SUEZ Everett LNG and Canaport LNG] facilities, while still significant to the region, are falling as U.S. domestic production rises, and as the price for LNG in foreign markets has become more compelling for cargoes."[47] Therefore, the alternative markets for LNG provide price and volume optionality to Repsol and GDF SUEZ. Consequently, the reduced LNG volumes are a concern for New England counterparties (i.e., uncertainty in terms of delivered volumes).

E. Mid-Atlantic Natural Gas Production

While the SOEP and imported LNG supplies have declined over the recent years, the natural gas production in the adjacent Mid-Atlantic region has experienced significant growth, which is forecasted to be sustainable. As illustrated in Figure III-10, the Marcellus Shale basin is located primarily in West Virginia, Ohio, Pennsylvania, and New York; while the Utica Shale formation lies beneath the Marcellus Shale, and extends from Kentucky into West Virginia, Ohio, Pennsylvania and New York, as well as northward to Ontario, Canada.

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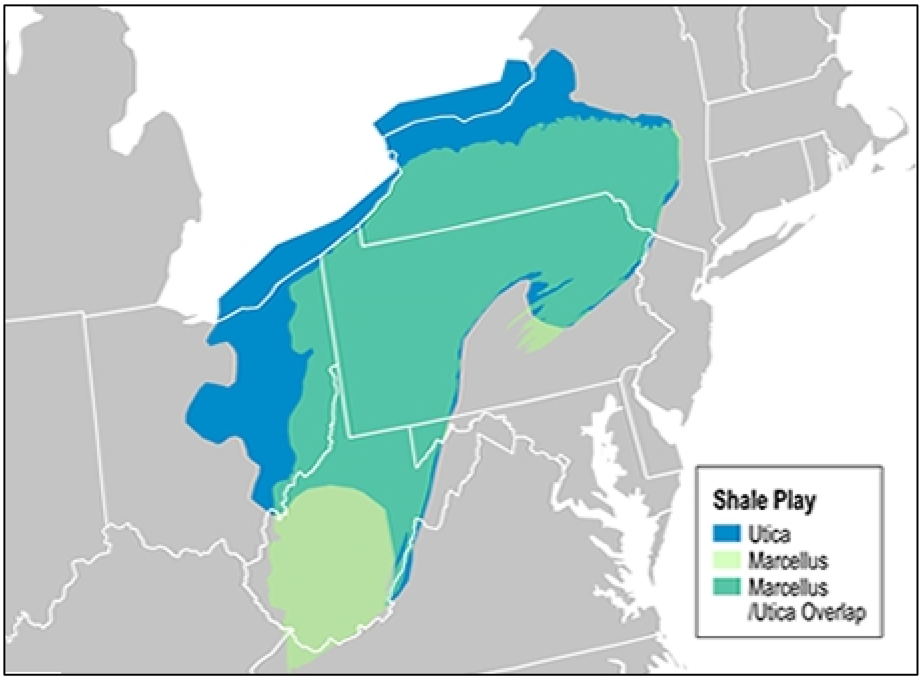
45 Source: Sussex based on historical prices through December 12, 2014 from SNL Financial and Bloomberg Professional; and forward settlement prices as of December 11, 2014 from Bloomberg Professional.

46 Federal Energy Regulatory Commission, "Winter 2013-14 Energy Market Assessment Report to the Commission", Docket No. AD06-3-000, October 17, 2013.

47 See, Northeast Gas Association, "Statistical Guide to the Northeast U.S. Natural Gas Industry 2014", December 2014, at 3 [clarification added].

Figure III-10: Marcellus and Utica Shale Gas Plays[48]



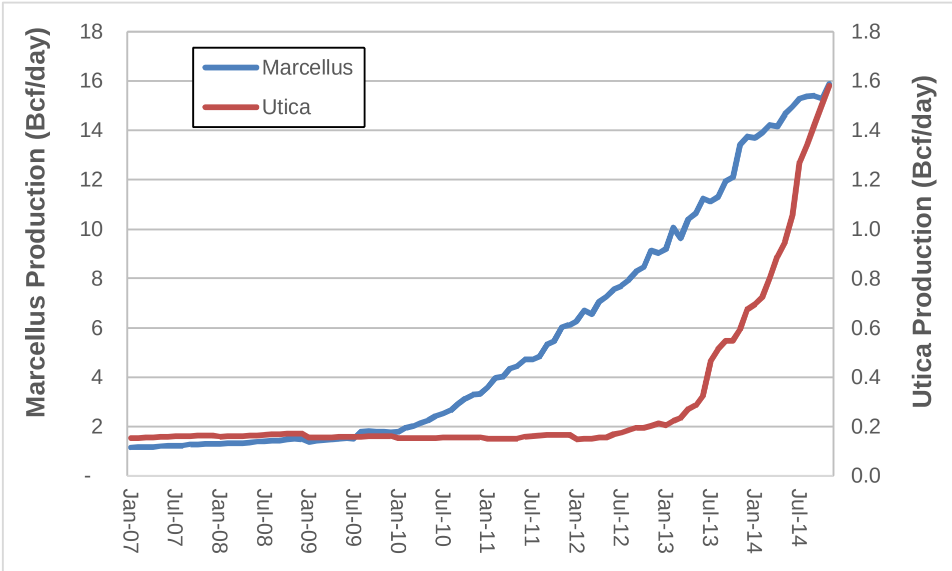
There has been a significant increase in the production of natural gas related to the Marcellus Shale and Utica Shale basins. As shown in Figure III-11 below, natural gas production from the Marcellus shale gas basin has increased from less than 2 Bcf/day in 2009 to nearly 16 Bcf/day in November 2014.[49] Likewise, natural gas production from the Utica shale gas basin has increased from approximately 200 MMcf/day in late 2012 to nearly 1.6 Bcf/day in November 2014.[50]

48 Source: U.S. Energy Information Administration.

49 Source: U.S. Energy Information Administration, “Drilling Productivity Report”, December 8, 2014.

50 Ibid.

Figure III-11: Total Gas Production[51]



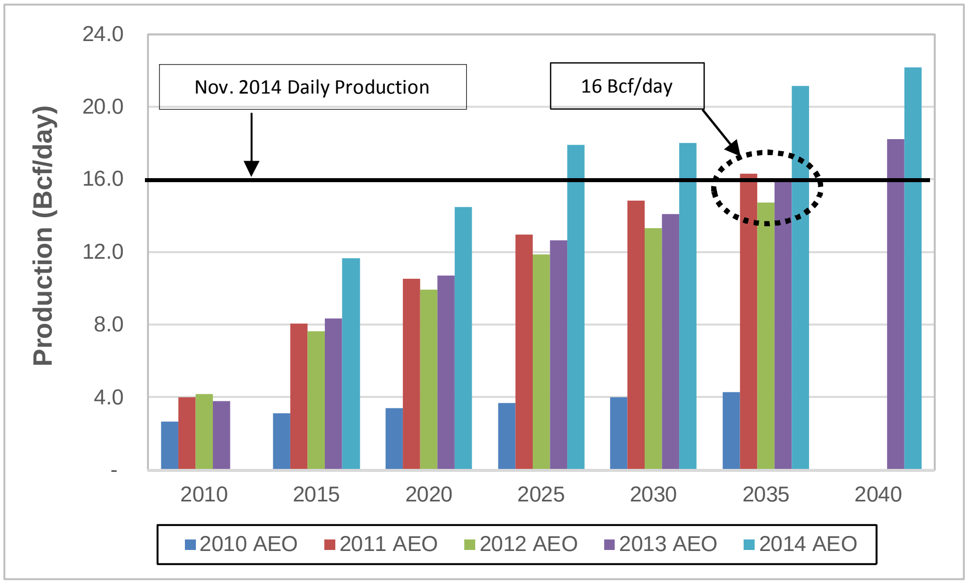
Actual production from the Marcellus Shale basin has already exceeded prior production forecasts issued by the U.S. Energy Information Administration ("EIA"). Specifically, as illustrated in Figure III-12 below, the 2010 EIA Annual Energy Outlook ("AEO") forecasted Northeast gas production of approximately 2.7 to 4.1 Bcf/day through 2035; the 2011-2013 AEOs projected Northeast gas production of approximately 16 Bcf/day by 2035; and the 2014 AEO projected Northeast gas production of 15 Bcf/day by 2020.[52] As shown in Figure III-12, actual production from the Marcellus Shale basin has already reached nearly 16 Bcf/day in November 2014.[53]

51 Ibid.

52 Source: U.S. Energy Information Administration, Annual Energy Outlooks from 2010 through 2014.

53 Source: U.S. Energy Information Administration, "Drilling Productivity Report", December 8, 2014.

Figure III-12: 2010-2014 EIA AEO Forecasted Northeast Natural Gas Production[54]



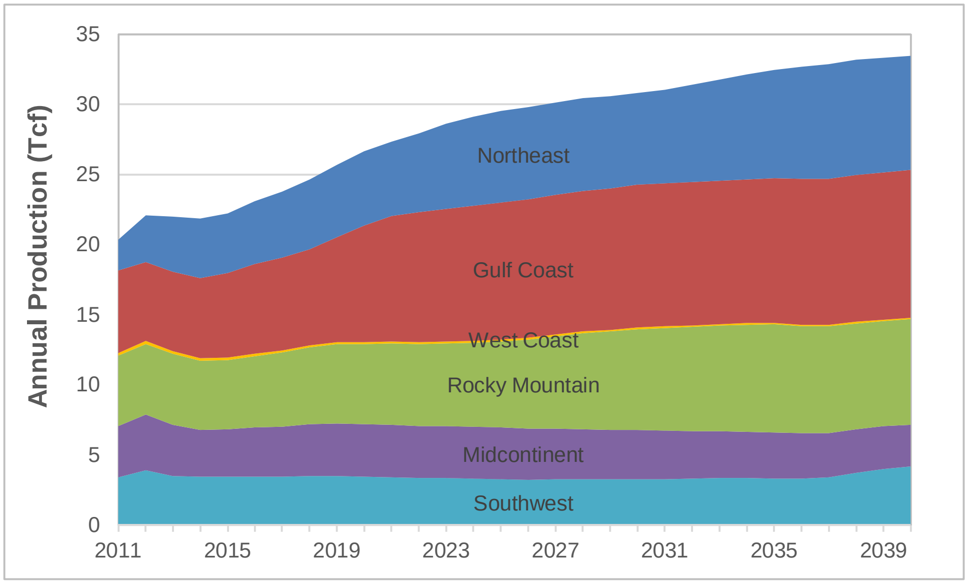
As illustrated in Figure III-12, the most recent EIA forecast (i.e., the 2014 AEO) indicates over 22 Bcf/day of Northeast gas production by 2040. Specifically, the EIA is forecasting an increase in annual Northeast natural gas production from approximately 11 Bcf/day in 2013 to 14 Bcf/day in 2020, and 22 Bcf/day in 2040.[55]

In terms of U.S. natural gas production, Figure III-14 below illustrates the increasing role of Northeast natural gas production relative to other natural gas production basins.

54 Source: U.S. Energy Information Administration, Annual Energy Outlooks from 2010 through 2014.

55 Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 with Projections to 2040, Lower 48 Natural Gas Production and Supply Prices by Supply Region, Reference Case, May 7, 2014.

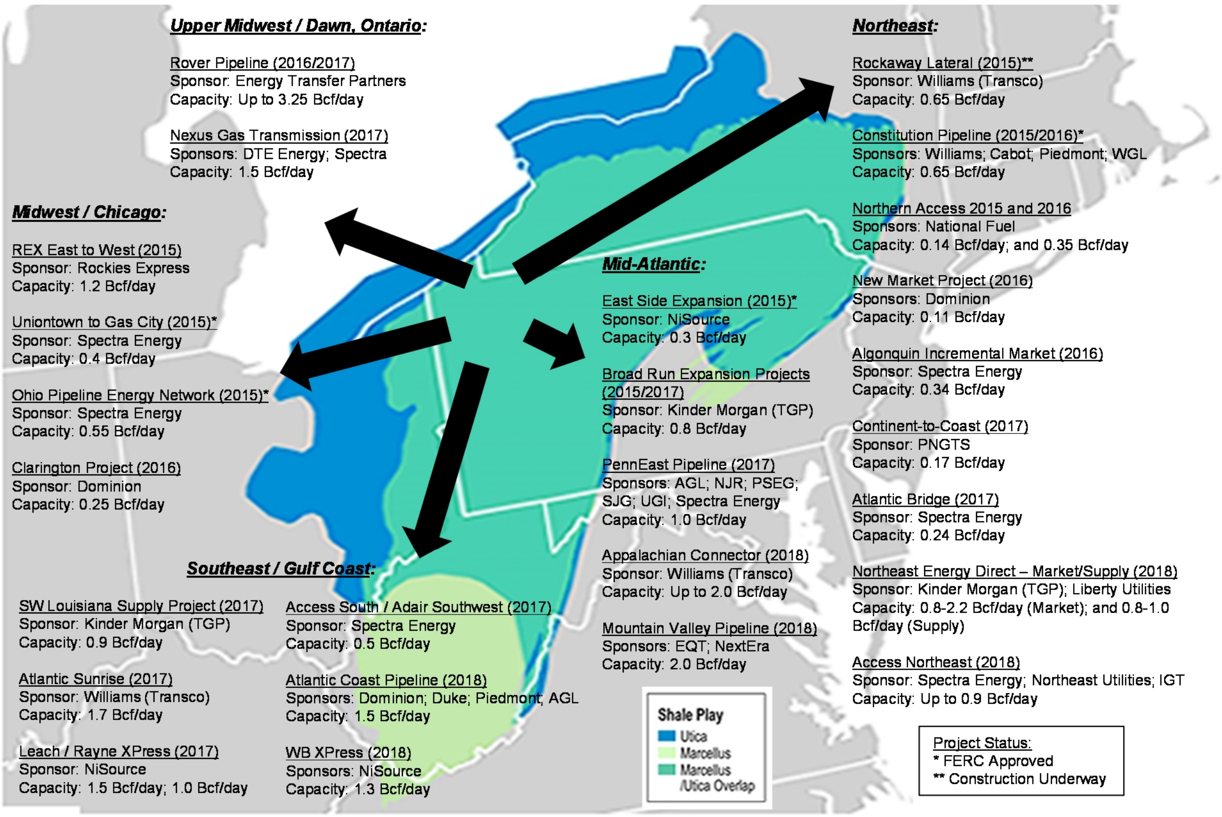
Figure III-14: 2014 EIA AEO Forecasted Natural Gas Production by Production Basin[56]



The significant increase in natural gas production from the Marcellus and Utica shale basins, coupled with the EIA's projection of sustained development of these two basins, results in the Mid-Atlantic becoming a primary natural gas supply source for the various regions of the U.S. As such, there has been a significant level of capital investments in infrastructure to develop and transport natural gas from the Marcellus and Utica shale gas basins. Over 25 Bcf/day of incremental pipeline capacity projects have been proposed to transport natural gas from the Mid-Atlantic production basins to various regions of the U.S. (i.e., Northeast, Mid-Atlantic, Southeast/Gulf Coast, and Midwest) and Canada (i.e., Dawn) through 2018 as shown in Figure III-16 below.

[56] Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 with Projections to 2040, Lower 48 Natural Gas Production and Supply Prices by Supply Region, May 7, 2014.

Figure III-16: Natural Gas Pipeline Infrastructure Activity[57]



A summary of the natural gas pipeline infrastructure projects that have been placed in-service in the Northeast U.S. region over the past six years is provided in Table III-1 below.

Table III-1: Northeast U.S. Natural Gas Pipeline Infrastructure Activity[58]

In-Service Year	Total Capacity	Total Capital Costs
2010	1.2 Bcf/day	$0.2 billion
2011	1.6 Bcf/day	$1.5 billion
2012	2.6 Bcf/day	$1.7 billion
2013	3.2 Bcf/day	$2.4 billion
2014	3.2 Bcf/day	$1.3 billion

As shown in Table III-1, there has been a significant level of incremental pipeline expansion activity built to serve the Northeast U.S. However, most of the projects placed into service have been focused on the New York and New Jersey markets, as noted by the EIA prior to the winter of 2013/2014.[59] Conversely, the New England region continues to experience pipeline capacity constraints

57 Based on a review and analysis of public documents as of December 19, 2014. Please note Figure III-16 does not include all of the proposed pipeline capacity projects.

58 Based on a review and analysis of public documents. Please note Table III-1 may not include all projects that were placed in-service in the Northeast U.S.

59 U.S. Energy Information Administration, "Today in Energy: Marcellus natural gas pipeline projects to primarily benefit New York and New Jersey", October 30, 2013.

from the adjacent Mid-Atlantic production area. Specifically, both of the interstate pipelines currently serving the New England region from the "South" and "West" (i.e., AGT and TGP) are fully subscribed and have experienced capacity constraints due to increased utilization. In a recent presentation, AGT reported an increasing number of days with no interruptible capacity available on its pipeline from 2010 to 2012; and no interruptible capacity available in 2013.[60] Similarly, TGP experienced interruptible transportation restrictions at Compressor Station 245 in New York 96% of the days in the 2013 summer and 100% of the days in the 2013/2014 winter.[61]

Recently, a number of pipeline infrastructure projects have been proposed to increase the delivery of supplies from the Marcellus Shale and relieve the capacity constraints into the New England and Atlantic Canada region. These projects include:

- Constitution Pipeline
- Kinder Morgan – Connecticut Expansion;
- Kinder Morgan – Northeast Energy Direct ("NED") Project;
- PNGTS – Continent-to-Coast ("C2C") Expansion Project;
- Spectra Energy – Algonquin Incremental Market ("AIM") Project;
- Spectra Energy – Atlantic Bridge; and
- Spectra Energy/Northeast Utilities/Iroquois – Access Northeast.

Given the decrease in natural gas supply from Atlantic Canada (i.e., SOEP and Deep Panuke) and the reduction in imported LNG volumes, coupled with the significant natural gas production developments in the Mid-Atlantic, the pipeline projects currently under development will provide the New England region with more access to the Marcellus Shale supplies and place downward pressure on regional energy prices.

Summaries of the projects that are already fully subscribed by customers and are in the approval or development phase are provided below (i.e., Constitution Pipeline, Kinder Morgan's Connecticut Expansion, and Spectra Energy's AIM Project). Ultimate construction of these new facilities is anticipated to provide some relief to the New England natural gas market. However, none of these projects deliver into the Joint Facilities, where Northern's loads are located. A detailed review of the other pipeline projects listed above is provided in Section VIII of this report.

1. Constitution Pipeline

Constitution Pipeline, which is owned by subsidiaries of Williams Partners, L.P., Cabot Oil & Gas Corporation ("Cabot"), Piedmont Natural Gas Company, Inc., and WGL Holdings, Inc., expects to transport 650,000 Dth/day of natural gas supplies from the Appalachian basin in northern Pennsylvania to the interconnect with Iroquois at Wright, New York. As shown in Figure III-22 below, the Constitution

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60 See, Spectra Energy, Presentation at the Northeast Gas Association's Regional Market Trends Forum, May 1, 2014, at 11.

61 See, Tennessee Gas Pipeline Company, "Embracing Change", Presentation at the Northeast Gas Association's Regional Market Trends Forum, May 1, 2014, at 7.

Pipeline project consists of an approximately 124-mile, 30-inch diameter pipeline from Susquehanna County, Pennsylvania to Schoharie County, New York, and various meter, regulation and delivery stations and related facilities. The estimated capital costs for the Constitution Pipeline is approximately $683 million.[62]

Figure III-22: Constitution Pipeline – Proposed Project Route[63]

Two major producers (i.e., Cabot and Southwestern Energy Services Company) have contracted for the full capacity of the Constitution Pipeline project (i.e., 500,000 Dth/day and 150,000 Dth/day, respectively).[64]

The FERC approved the construction of the Constitution Pipeline in early December 2014; and construction is slated to begin in the first quarter of 2015.[65]

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[62] See, Constitution Pipeline Company, LLC, Application for Certificates of Public Convenience and Necessity, FERC Docket No. CP13-499-000, June 13, 2013.

[63] Source: Constitution Pipeline Company, LLC, Application for Certificates of Public Convenience and Necessity, FERC Docket No. CP13-499-000, June 13, 2013.

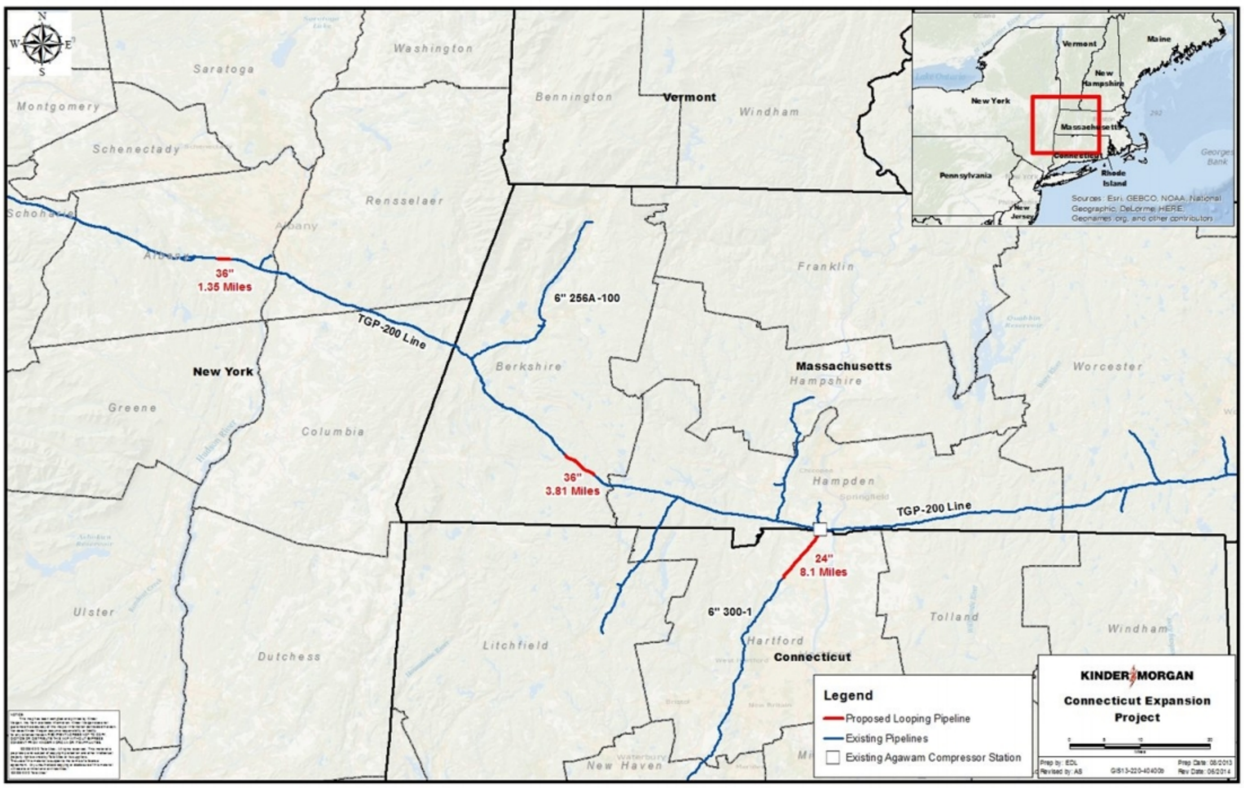
[64] See, Federal Energy Regulatory Commission, Order Issuing Certificates and Approving Abandonment, FERC Docket No. CP13-499-000, December 2, 2014.

[65] See, Constitution Pipeline Company, LLC, "Constitution Pipeline Receives FERC Approval to Construct Project", December 3, 2014.

2. Kinder Morgan – Connecticut Expansion Project

The Connecticut Expansion Project proposed by Kinder Morgan will expand the Tennessee system in order to deliver supplies to serve three Connecticut LDCs (i.e., Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, and Yankee Gas Services Company). The incremental capacity of 72,100 Dth/day is fully subscribed by the project shippers, with an in-service date of November 1, 2016. As illustrated in Figure III-23 below, the Connecticut Expansion Project will consist of three new pipeline looping segments in New York, Massachusetts, and Connecticut, and compressor station modifications. Based on Kinder Morgan's application for a certificate of public convenience and necessity filed with the FERC in July 2014, the estimated capital costs for the Connecticut Expansion Project is approximately $86 million.[66]

Figure III-23: Connecticut Expansion Project – Proposed Project Route[67]



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66 See, Tennessee Gas Pipeline Company, L.L.C., Abbreviated Application of Tennessee Gas Pipeline Company, L.L.C. for a Certificate of Public Convenience and Necessity to Construct, Install, Modify, Operate, and Maintain Certain Pipeline and Compression Facilities, FERC Docket No. CP14-529-000, July 31, 2014.

67 Source: Federal Energy Regulatory Commission, Notice of Intent to Prepare an Environmental Assessment for the Proposed Connecticut Expansion Project, Request for Comments on Environmental Issues, Notice of Public Scoping Meetings, and Notice of Environmental Site Reviews, FERC Docket No. CP14-529-000, October 10, 2014.

The Connecticut PURA pre-approved the LDCs precedent agreements for the Connecticut Expansion Project, in addition to Spectra Energy's AIM Project (as discussed below), in late 2013.[68] The Connecticut Expansion Project is currently under review by the FERC, with a decision expected in 2015.[69]

3. Spectra Energy – Algonquin Incremental Market Project

Spectra Energy's proposed AIM Project is an expansion of its Algonquin system, which will provide an incremental 342,000 Dth/day of natural gas supplies from an interconnection with Millennium at Ramapo, New York to multiple delivery points in Connecticut, Rhode Island, and Massachusetts by November 1, 2016. The AIM Project consists of approximately 37.6 miles of take-up and relay, loop and lateral pipeline facilities; modifications to six compressor stations and 24 existing M&R stations; and construction of three new M&R stations (see also Figure III-24 below). Based on Spectra Energy's application for a certificate of public convenience and necessity filed with the FERC in February 2014, the estimated capital costs for the AIM project is approximately $1 billion.[70]

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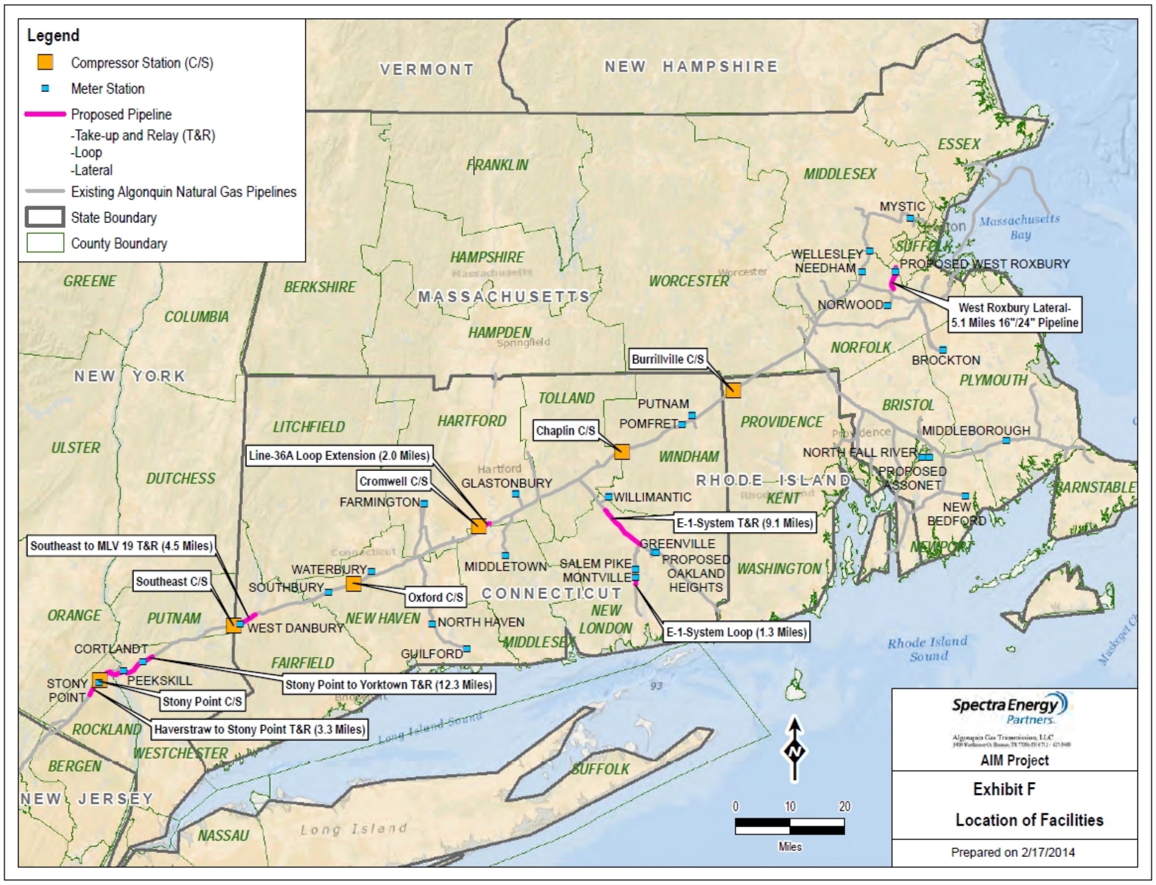
68 See, Connecticut Public Utilities Regulatory Authority, Decision, PURA Investigation of Connecticut's Local Distribution Companies' Proposed Expansion Plans to Comply with Connecticut's Comprehensive Energy Strategy, Docket No. 13-06-02, November 22, 2013.

69 See, Tennessee Gas Pipeline Company, L.L.C., Abbreviated Application of Tennessee Gas Pipeline Company, L.L.C. for a Certificate of Public Convenience and Necessity to Construct, Install, Modify, Operate, and Maintain Certain Pipeline and Compression Facilities, FERC Docket No. CP14-529-000, July 31, 2014.

70 See, Algonquin Gas Transmission, LLC, Abbreviated Application for a Certificate of Public Convenience and Necessity and for Related Authorizations, FERC Docket No. CP14-96-000, February 28, 2014.

Figure III-24: AIM Project – Proposed Project Route[71]



The AIM Project is fully subscribed for a term of 15 years by eight LDCs and two municipals; specifically, NSTAR Gas Company, Bay State d/b/a Columbia Gas of Massachusetts, Boston Gas Company d/b/a National Grid, Colonial Gas Company d/b/a National Grid, The Narragansett Electric Company d/b/a National Grid, Connecticut Natural Gas, Southern Connecticut Gas, Yankee Gas Services Company, Middleborough Gas and Electric, the City of Norwich, Connecticut.[72] The Connecticut PURA and Massachusetts DPU have pre-approved the LDCs precedent agreements for the AIM Project in late 2013 and early 2014, respectively.[73] The project is currently under review by the FERC, with a decision expected by late April 2015.[74]

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[71] Ibid.

[72] Ibid.

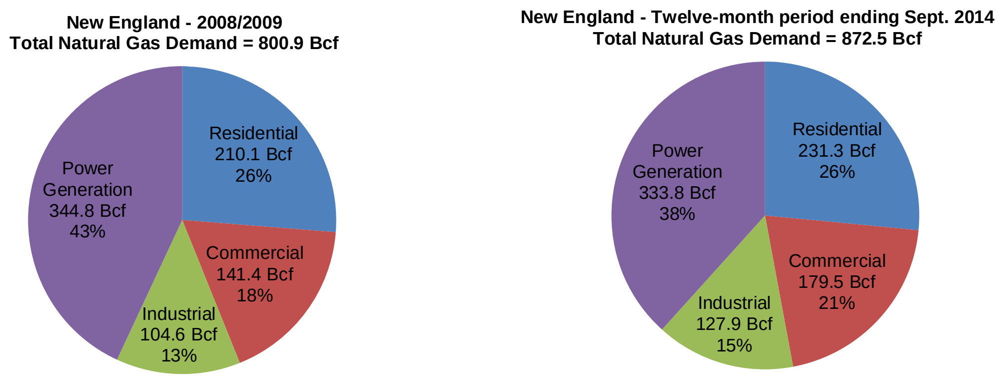
[73] See, Connecticut Public Utilities Regulatory Authority, Decision, PURA Investigation of Connecticut's Local Distribution Companies' Proposed Expansion Plans to Comply with Connecticut's Comprehensive Energy Strategy, Docket No. 13-06-02, November 22, 2013; and Massachusetts Department of Public Utilities, Orders issued in Docket Nos. DPU 13-157, DPU 13-158, and DPU 13-159 January 31, 2014.

[74] See, Federal Energy Regulatory Commission, Notice of Revised Schedule for Environmental Review of the Algonquin Incremental Market Project, FERC Docket No. CP14-96-000, December 10, 2014.

F. Regional Natural Gas Demand

The demand for natural gas in the New England region has increased over the past several years. Specifically, annual natural gas demand has increased by approximately 10% from approximately 800.9 Bcf (i.e., 2,194 MMcf/day) in the 2008/2009 split-year to 872.5 Bcf (i.e., 2,390 MMcf/day) in the twelve month period ending September 2014 (see Figure III-17 below). Over that same time period, winter natural gas demand increased by 7% from 430.9 Bcf (i.e., 2,854 MMcf/day) to 462.2 Bcf (i.e., 3,061 MMcf/day), while summer natural gas demand increased by 11% from 370.0 Bcf (i.e., 1,729 MMcf/day) to 410.3 Bcf (i.e., 1,917 MMcf/day).[75]

Figure III-17: New England Natural Gas Consumption[76]



Although the regional natural gas demand has grown in both the summer and winter periods, the New England market is still a winter peaking market as illustrated in Figure III-18 below. The peak winter monthly demand over the past six winters occurred in January 2011 when the monthly demand was 113.4 Bcf, or approximately 3,658 MMcf/day.[77]

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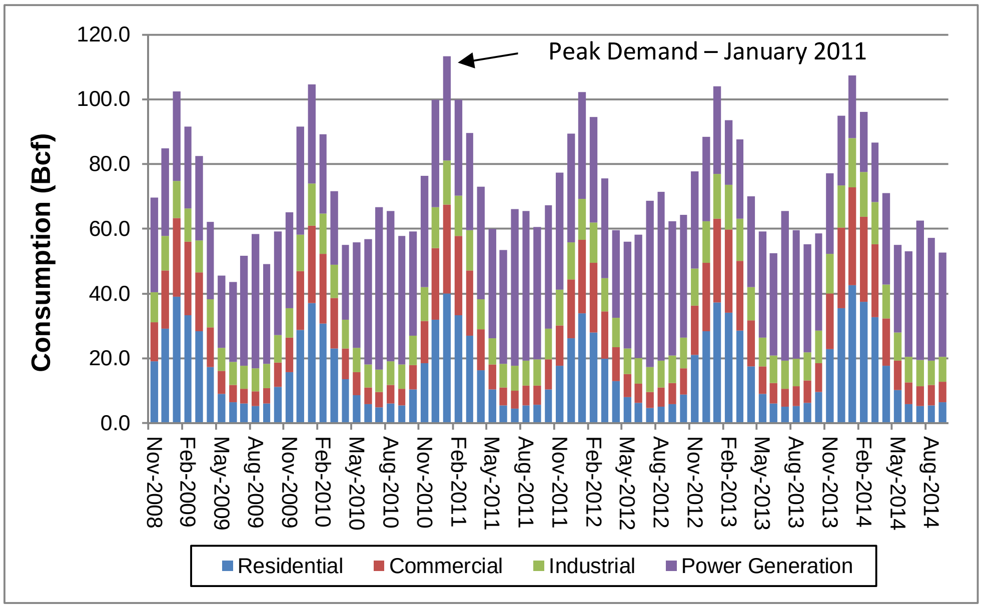
75 Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use for Massachusetts, Connecticut, Rhode Island, Vermont, New Hampshire and Maine, release date November 28, 2014. Data for certain months in 2014 were estimated.

76 Ibid.

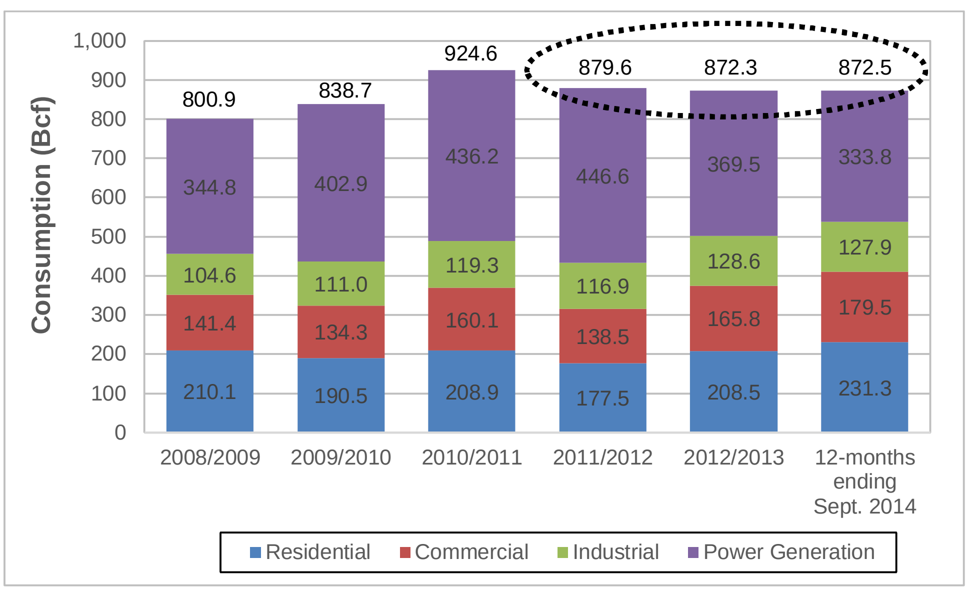
77 Ibid.

Figure III-18: Monthly Natural Gas Consumption by End Use[78]



As illustrated in Figure III-19 below, total natural gas demand in New England has been relatively consistent since 2011/2012 (i.e., total annual demand in 2011/2012 of approximately 880 Bcf, total annual demand in 2012/2013 of approximately 872 Bcf, and total demand for the twelve-month period ending September 2014 of approximately 873 Bcf).[79]

Figure III-19: Annual Natural Gas Consumption by End Use[80]



78 Ibid.

79 Ibid.

80 Ibid.

However, as shown in Figure III-19, the demand by end-use segment has been different over the three most recent time periods (i.e., 2011/2012, 2012/2013, and twelve-month period ending September 2014), with the power generation segment representing a smaller percentage of the total demand over the past two time periods. The natural gas demand by the power generation segment has been limited, particularly during the winter peak periods, as a result of insufficient pipeline capacity into the New England region. Specifically, the lack of pipeline capacity into the region has led to the reliance on alternative fuels (e.g., oil and coal) for generation. ISO New England ("ISO-NE") has implemented a Winter Reliability Program to address the reliability risk associated with insufficient pipeline capacity into the region. As a result, during this past winter (i.e., winter of 2013/2014), natural gas-fired generation produced below their total capacity; while coal and oil-fired generation ran at or near full capacity.[81] This issue was discussed by the FERC in its "*Winter 2014-15 Energy Market Assessment*":

> *Last winter [i.e., 2013/2014] New England avoided significant spikes in natural gas demand, despite high residential and commercial demand. Various other sources of generation including oil and coal, plus power imports, helped reduce natural gas demand from New England power generators by 20%.*[82]

With respect to LDC growth, and specifically the residential and commercial segments, the price spread between natural gas and alternative fuels has been a major driver of demand as customers convert from alternative fuels (e.g., oil) to natural gas. As shown in Figure III-20 below, the price spread between oil and natural gas will likely continue to spur natural gas demand in the residential and commercial segments.

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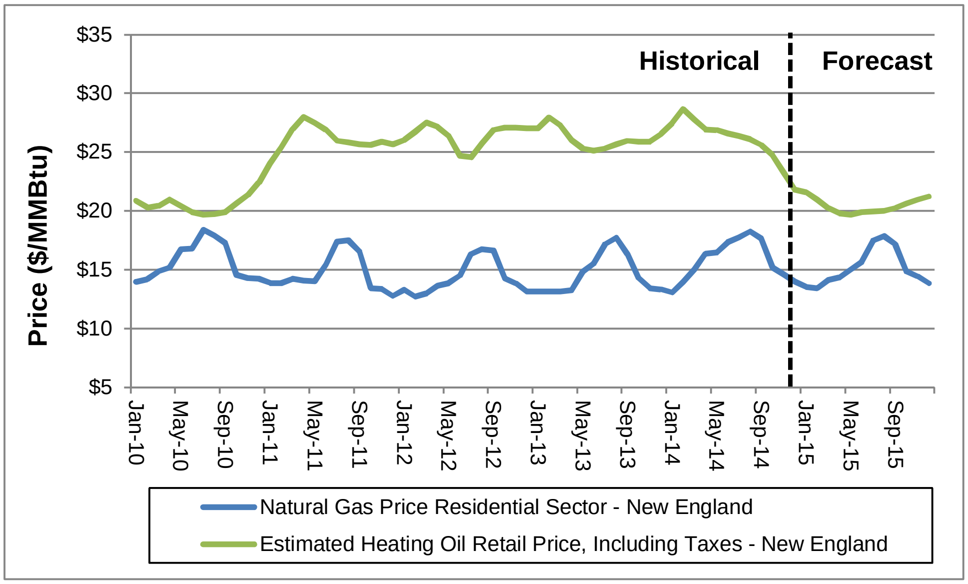
81 See, Forbes, "Winter 2014: How Fuel Oil Saved the Day in New England", April 30, 2014.

82 Federal Energy Regulatory Commission, "Winter 2014-15 Energy Market Assessment", presentation dated October 16, 2014, at 6 [clarification added].

Figure III-20: Natural Gas vs. Oil Prices[83]



In addition to the price spread between oil and natural gas, there are various regional and state activities that will continue to affect natural gas demand in the New England region. A review of certain regional and state activities is provided below.

1. Regional Activities – NESCOE

In December 2013, the governors of the six New England states, in coordination with ISO-NE and through the New England States Committee on Electricity ("NESCOE"), launched the Regional Energy Infrastructure Initiative, which includes among its goals an investment in natural gas pipeline(s) to the New England region. Although NESCOE had been active (e.g., facilitating a discussion regarding an alternative funding mechanism for new pipeline capacity into the New England region), the activity level has decreased pending a Massachusetts Department of Energy Resources study regarding pipeline capacity requirements.

2. State Activities

In addition to the collaborative regional efforts, several of the New England states have undertaken activities that are expected to impact the demand for natural gas through LDC distribution expansions and programs promoting customer conversions from alternative fuels.

[83] Sources: U.S. Energy Information Administration, "Short-Term Energy Outlook and Winter Fuels Outlook", Tables 2 and 5b, December 9, 2014; and U.S. Energy Information Administration, "Weekly Heating Oil and Propane Prices", accessed on December 16, 2014. Please note, the heating oil retail price for the New England region was estimated based on the historical relationship between weekly U.S. and New England No. 2 heating oil prices.

a) Connecticut

The Connecticut Department of Energy and Environmental Protection issued its Comprehensive Energy Strategy for Connecticut ("CT CES") in February 2013, which aimed to increase the consumption of natural gas through natural gas conversions. Specifically, the CT CES set a goal of increasing the availability of natural gas to approximately 300,000 additional customers by 2020.[84] To comply with the CT CES recommendations, the three Connecticut LDCs (i.e., Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, and Yankee Gas Services Company) jointly filed a natural gas expansion plan with the Connecticut Public Utilities Regulatory Authority ("PURA") in June 2013, which included the LDCs incremental pipeline capacity commitments on Kinder Morgan's Connecticut Expansion Project and Spectra Energy's AIM Project (as discussed in Section VIII).[85] In November 2013, the Connecticut PURA approved the LDCs joint expansion plan to convert approximately 280,000 customers to natural gas service over a 10-year period, as well as the LDCs precedent agreements for the Connecticut Expansion Project and AIM Project.[86]

b) Maine

The state of Maine enacted legislation (i.e., the Maine Energy Cost Reduction Act), which authorizes the MPUC to enter into, or direct a utility to execute, a contract for natural gas pipeline capacity (i.e., an Energy Cost Reduction Contract ("ECRC")). The legislation provided certain limits such as the pipeline capacity contract could not be greater than 200 MMcf/day or $75 million per year.[87] In March 2014, the MPUC commenced a two-phase regulatory proceeding to (i) determine the parameters and set the framework for considering ECRCs, and (ii) examine and evaluate ECRC proposals.[88] As discussed in Section VIII, ECRC proposals were submitted to the MPUC by PNGTS (i.e., PNGTS C2C Project), Spectra Energy (i.e., Access Northeast and Atlantic Bridge projects) and Kinder Morgan (i.e., NED Project) in early December 2014 as part of Phase II of the MPUC's regulatory proceeding.

c) Massachusetts

In June 2014, Massachusetts enacted legislation (i.e., H. 4164, An Act Relative to Natural Gas Leaks) with a provision that encourages the expansion of natural gas distribution service in the state. Specifically, Section 3 of H. 4164 authorizes the Massachusetts LDCs to petition for approval of "cost-effective programs that reasonably accelerate the expansion of and conversion to natural gas usage in the commonwealth."

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84 See, The Connecticut Department of Energy and Environmental Protection, "2013 Comprehensive Energy Strategy for Connecticut", February 19, 2013, at 119.

85 See, Connecticut's Gas LDCs Joint Natural Gas Infrastructure Expansion Plan, June 14, 2013.

86 See, Connecticut Public Utilities Regulatory Authority, Decision, PURA Investigation of Connecticut's Local Distribution Companies' Proposed Expansion Plans to Comply with Connecticut's Comprehensive Energy Strategy, Docket No. 13-06-02, November 22, 2013.

87 See, H.P. 1128 – L.D. 1559, An Act to Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment, 35-A MRSA §1901 et seq.

88 See, Maine Public Utilities Commission, "Order Part 2 – Schedule and Scope", MPUC Docket No. 2014-00071, May 5, 2014.

As a result of these various regional and state initiatives, the New England LDCs will continue to experience growth from customer conversions. Stated differently, there will likely be an increase in natural gas demand by the residential, commercial, and industrial segments, which have historically accounted for approximately 60% of the total natural gas demand in the region.[89]

In addition, natural gas-fired generation will continue to be one of the primary generation resources in the New England region. As discussed previously, natural gas demand by the power generation segment represents approximately 40% of the regional natural gas consumption. In 2013, there were 350 generators with a total of 31,000 MW of generating capacity in ISO-NE, with natural gas and dual fuel (i.e., natural gas and oil-fired) generation accounting for approximately 45% of the total capacity and 40% of the total electric energy production.[90]

Based on a review of the most recent generator interconnection request queue for the ISO-NE region, natural gas-fired, dual fuel (i.e., natural gas and oil-fired), and wind projects represented the majority of the total proposed new generation capacity in the ISO-NE. As shown in Figure III-21 below, there are 90 generation projects in ISO-NE with a total capacity of 8,298 MW in various stages of development. Of the 90 projects (totaling approximately 8,300 MW), natural gas-fired generation (i.e., 9 projects) represents approximately 1,460 MW, and dual fuel (i.e., natural gas and oil-fired) generation (i.e., 12 projects) represents approximately 3,100 MW.[91] In total, the 21 projects (i.e., natural gas and dual fuel) account for more than half (i.e., approximately 55%) of the total proposed generation capacity.

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89 Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use for Massachusetts, Connecticut, Rhode Island, Vermont, New Hampshire and Maine, release date September 30, 2014.

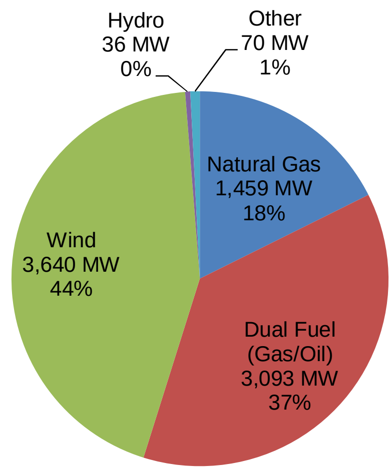
90 See, ISO New England. "Resource Mix", accessed on October 14, 2014.

91 See, ISO New England, "Interconnection Requests for New England Control Area Generation, Elective Transmission Upgrade and Transmission Service Requests", December 1, 2014.

Figure III-21: ISO-NE Generator Interconnection Request Queue by Fuel Type[92]

ISO-NE Interconnection Request Queue
Total Net Capacity = 8,298 MW

Fuel Type	Number of Projects
Natural Gas	9
Dual Fuel (Gas/Oil)	12
Wind	35
Hydro	10
Other	24
Total	90



In addition, there are several generating plants, none of which are natural gas-fired generation, that have recently retired or have plans to retire in the next few years, which will likely have significant implications for natural gas demand. These generation retirements include:

- Salem Harbor Station (749 MW) – four coal and oil units retired in June 2014;
- Mount Tom (146 MW) – coal unit to be retired by year-end 2014;
- Vermont Yankee (604 MW) – nuclear facility to be decommissioned by year-end 2014;
- Brayton Point Station (1,535 MW) – four coal and oil units to be retired by June 2017;
- Bridgeport Harbor (180 MW) – a coal unit to be retired by June 2017; and
- Norwalk Harbor Station (342 MW) – three oil-fired units to be retired by June 2017.[93]

Combined, these generation retirements represent over 10% of the total generating capacity in ISO-NE (i.e., 3,776 MW of 31,000 MW) and over 20% of the generating capacity that is not natural gas-fired or dual-fuel (i.e., 3,776 MW of approximately 17,000 MW). These announced retirements, as well as the potential for additional coal and oil-fired generation retirements,[94] will likely increase the reliance on natural gas as new gas-fired generators are built to replace retiring units and/or existing units will

92 Ibid.

93 See, ISO New England, "Status of Non-Price Retirement Requests", October 6, 2014; and ISO New England. "Resource Mix", accessed on October 14, 2014.

94 In a study released in late 2012, ISO-NE identified 28 coal and oil-fired generating units, representing nearly 8,300 MW of capacity, were "at-risk" for retirement by 2020. In addition, ISO-NE concluded that if all 28 units were retired, approximately 6,300 MW of resources would need to be replaced to meet the forecasted capacity requirements. See, ISO New England, "Strategic Transmission Analysis: Generation Retirements Study", December 13, 2012, at 11, 15.

need to run more often. For example, Footprint Power LLC, the owner of the Salem Harbor Station, plans to build a new 674 MW combined cycle natural gas facility at the existing site by June 1, 2017.[95]

Therefore, natural gas will continue to be one of the main fuel sources for the power generation segment in New England, and continue to compete for gas supplies delivered to New England particularly during the winter period.

G. Natural Gas Price Analysis

The fundamental changes in the regional market conditions are reflected in regional natural gas prices. Specifically, the significant increase in Marcellus and Utica natural gas production has placed downward pressure on certain market area price indices (e.g., the Dominion South Point price index). However, the New England region has experienced high natural gas prices and significant price volatility due to a combination of increased natural gas demand, the reduction in natural gas supplies from the "North" (i.e., from Sable Island and imported LNG), and insufficient pipeline capacity to deliver supplies from the Mid-Atlantic production areas to the New England markets.

The remainder of this section summarizes a regional natural gas price analysis, which includes a review of the historical and forecasted prices for New England (i.e., represented by the Algonquin Citygates, Tennessee at Dracut, and Tennessee Zone 6 natural gas price indices), as well as the adjacent Mid-Atlantic region (i.e., the TETCO M3 natural gas price index was used to represent this area), the Gulf Coast (i.e., the Henry Hub natural gas price index was used to represent this area), and Canadian supplies (i.e., the Dawn Hub natural gas price index was used to represent this area). Definitions for these natural gas price indices are provided below:[96]

- Algonquin Citygates ("ALGCG") – Delivery points in Connecticut, Massachusetts and Rhode Island off of Algonquin Gas Transmission.
- Tennessee at Dracut ("Dracut"): Tennessee Gas Pipeline's Dracut interconnects with Maritimes & Northeast Pipeline is located near Middlesex, Massachusetts. It is the primary delivery point in the region for Sable Island production.
- Tennessee Zone 6 ("TENNZ6"): Citygate deliveries in Connecticut, Massachusetts and Rhode Island off of Tennessee Gas Pipeline. Further transport on local distribution company systems may be made to Vermont, New Hampshire and Maine.
- TETCO M3 – Market Area 3 zone of Texas Eastern Pipeline, which runs from Westmoreland County, Pa., to Morris County, N.J.
- Henry Hub – In Vermilion Parish in South Louisiana, the Hub has 14 interconnecting pipelines. Pipelines include Trunkline Gas, Transcontinental Gas Pipeline, Columbia Gulf Transmission, Texas Gas Transmission, Sabine Pipe Line, Natural Gas Pipeline Co., Southern Natural Gas and Gulf South Pipeline.

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95 See, Footprint Power Salem Harbor Development LP, "Footprint Power Sale Harbor Development LP's Application for Deferral of Capacity Supply Obligation", Docket No. ER15-60-000, October 7, 2014.

96 Source: Sussex as obtained from SNL Financial.

- Dawn Ontario ("Dawn") – Gathering point for 15 adjacent storage pools in Ontario. Storage is owned and operated by distributor Union Gas. Dawn is interconnected with TransCanada Pipelines.

Table III-2 below summarizes the average daily spot prices for each of the identified natural gas price points over the past six split-years.

Table III-2: Average Daily Spot Prices ($/MMBtu)[97]

Season	Split-Yr (Nov-Oct)	Henry Hub	TETCO M3	Dracut	TENNZ6	ALGCG	Dawn
Winter	2008/2009	$ 5.28	$ 6.79	$ 7.73	$ 6.71	$ 6.98	$ 5.67
Winter	2009/2010	$ 4.90	$ 5.68	$ 5.84	$ 5.92	$ 5.96	$ 5.19
Winter	2010/2011	$ 4.10	$ 5.97	$ 6.46	$ 6.52	$ 6.57	$ 4.59
Winter	2011/2012	$ 2.77	$ 3.05	$ 3.85	$ 3.86	$ 3.86	$ 3.24
Winter	2012/2013	$ 3.47	$ 4.14	$ 9.28	$ 9.31	$ 9.64	$ 3.83
Winter	2013/2014	$ 4.63	$ 8.53	$ 15.76	$ 14.93	$ 15.09	$ 8.06
Winter Average (2008/09-2013/14)		**$ 4.19**	**$ 5.69**	**$ 8.15**	**$ 7.87**	**$ 8.02**	**$ 5.10**
Summer	2008/2009	$ 3.52	$ 3.85	$ 5.65	$ 3.92	$ 3.89	$ 3.78
Summer	2009/2010	$ 4.19	$ 4.52	$ 4.47	$ 4.57	$ 4.59	$ 4.54
Summer	2010/2011	$ 4.15	$ 4.41	$ 4.57	$ 4.61	$ 4.63	$ 4.46
Summer	2011/2012	$ 2.69	$ 2.86	$ 3.17	$ 3.28	$ 3.29	$ 2.92
Summer	2012/2013	$ 3.77	$ 3.80	$ 4.23	$ 4.20	$ 4.26	$ 4.16
Summer	2013/2014	$ 4.22	$ 2.93	$ 3.77	$ 3.68	$ 3.60	$ 4.38
Summer Average (2008/09-2013/14)		**$ 3.76**	**$ 3.73**	**$ 4.31**	**$ 4.04**	**$ 4.04**	**$ 4.04**
Annual	2008/2009	$ 4.25	$ 5.07	$ 6.12	$ 5.07	$ 5.17	$ 4.56
Annual	2009/2010	$ 4.48	$ 5.00	$ 5.04	$ 5.13	$ 5.16	$ 4.81
Annual	2010/2011	$ 4.13	$ 5.06	$ 5.35	$ 5.40	$ 5.43	$ 4.51
Annual	2011/2012	$ 2.72	$ 2.94	$ 3.45	$ 3.52	$ 3.53	$ 3.06
Annual	2012/2013	$ 3.65	$ 3.94	$ 6.32	$ 6.31	$ 6.48	$ 4.02
Annual	2013/2014	$ 4.39	$ 5.24	$ 8.73	$ 8.33	$ 8.35	$ 5.90
Annual Average (2008/09-2013/14)		**$ 3.94**	**$ 4.54**	**$ 5.84**	**$ 5.63**	**$ 5.69**	**$ 4.48**

Given the relatively tight range between the New England price indices (i.e., six-year annual average ranged from $5.63/MMBtu to $5.84/MMBtu), the ALGCG natural gas price index was used as the natural gas price proxy for the New England region in the remaining analyses. However, it is important to note that the average winter price at Dracut in the most recent winter (i.e., 2013/2014) varied significantly from the ALGCG price index (i.e., $15.76/MMBtu vs. $15.09/MMBtu, respectively). The recent separation in regional prices was discussed by the NEB; specifically, it noted that natural gas

97 Source: Sussex based on the simple average of spot prices from SNL Financial.

prices for markets downstream of ALGCG (e.g., Atlantic Canada) are priced at an additional premium to the ALGCG price index.[98]

As illustrated in Table III-2, the average natural gas prices at Dawn and in the Mid-Atlantic region (i.e., TETCO M3) have historically been at a premium to the Gulf Coast (i.e., Henry Hub), and the average natural gas prices in New England (i.e., ALGCG) have been at an additional premium to the Dawn and Mid-Atlantic natural gas prices. Specifically, the six-year annual average prices for the Henry Hub, Dawn, and TETCO M3 price indices were approximately $4.00/MMBtu, $4.50/MMBtu, and $4.50/MMBtu, respectively; whereas the six-year annual average prices in New England (i.e., ALGCG) was approximately $5.70/MMBtu. Stated differently, the six-year annual average premium between the Mid-Atlantic/Dawn and Henry Hub prices was approximately $0.60/MMBtu, while the New England six-year annual average premium to the Mid-Atlantic/Dawn prices was approximately $1.15/MMBtu.

Table III-3 below summarizes the basis differentials over the past six split-years.

Table III-3: Average Basis Differentials ($/MMBtu)[99]

Season	Split-Yr (Nov-Oct)	TETCO M3-Henry Hub	ALGCG-Henry Hub	Dawn-Henry Hub	ALGCG-TETCO M3	ALGCG-Dawn
Winter	2008/2009	$ 1.51	$ 1.70	$ 0.39	$ 0.19	$ 1.32
Winter	2009/2010	$ 0.79	$ 1.06	$ 0.29	$ 0.27	$ 0.77
Winter	2010/2011	$ 1.88	$ 2.47	$ 0.49	$ 0.59	$ 1.98
Winter	2011/2012	$ 0.28	$ 1.09	$ 0.47	$ 0.81	$ 0.62
Winter	2012/2013	$ 0.67	$ 6.17	$ 0.36	$ 5.50	$ 5.81
Winter	2013/2014	$ 3.89	$ 10.46	$ 3.43	$ 6.56	$ 7.03
Winter Average (2008/09-2013/14)		**$ 1.50**	**$ 3.83**	**$ 0.90**	**$ 2.32**	**$ 2.92**
Summer	2008/2009	$ 0.34	$ 0.37	$ 0.26	$ 0.04	$ 0.11
Summer	2009/2010	$ 0.34	$ 0.40	$ 0.35	$ 0.07	$ 0.05
Summer	2010/2011	$ 0.26	$ 0.48	$ 0.31	$ 0.21	$ 0.17
Summer	2011/2012	$ 0.17	$ 0.61	$ 0.24	$ 0.44	$ 0.37
Summer	2012/2013	$ 0.03	$ 0.48	$ 0.39	$ 0.45	$ 0.09
Summer	2013/2014	$ (1.29)	$ (0.62)	$ 0.16	$ 0.67	$ (0.79)
Summer Average (2008/09-2013/14)		**$ (0.03)**	**$ 0.29**	**$ 0.28**	**$ 0.31**	**$ 0.00**
Annual	2008/2009	$ 0.82	$ 0.92	$ 0.31	$ 0.10	$ 0.61
Annual	2009/2010	$ 0.52	$ 0.68	$ 0.33	$ 0.15	$ 0.35
Annual	2010/2011	$ 0.93	$ 1.30	$ 0.38	$ 0.37	$ 0.92
Annual	2011/2012	$ 0.22	$ 0.81	$ 0.34	$ 0.59	$ 0.47
Annual	2012/2013	$ 0.29	$ 2.84	$ 0.38	$ 2.54	$ 2.46
Annual	2013/2014	$ 0.85	$ 3.96	$ 1.51	$ 3.11	$ 2.45
Annual Average (2008/09-2013/14)		**$ 0.61**	**$ 1.75**	**$ 0.54**	**$ 1.14**	**$ 1.21**

[98] See, National Energy Board, "Market Snapshot: Continuing High Prices in the Maritimes' Distinct Natural Gas Market", December 11, 2014.

[99] Source: Sussex analysis of the simple average of daily basis differentials based on spot prices from SNL Financial.

As shown in Table III-3, the annual price premium (i.e., basis differential) between ALGCG and Henry Hub has increased significantly over the past six split-years. Specifically, the annual ALGCG to Henry Hub basis differential increased from an average of approximately $0.90/MMBtu over the 2008/2009 to 2011/2012 split-years to nearly $3.00/MMBtu in 2012/2013 and $4.00/MMBtu in 2013/2014.

The ALGCG to Dawn basis differential has also increased significantly over the past two split-years. Specifically, the ALGCG to Dawn basis increased from an annual average of approximately $0.60/MMBtu over the four split-years from 2008/2009 to 2011/2012 to approximately $2.50/MMBtu in the two most recent split-years (i.e., 2012/2013 and 2013/2014).

Similarly, the ALGCG to TETCO M3 basis increased from an annual average of approximately $0.30/MMBtu over the four split-years from 2008/2009 to 2011/2012 to approximately $2.50/MMBtu in 2012/2013 and approximately $3.10/MMBtu in 2013/2014. As noted by the EIA prior to the winter of 2013/2014, the difference between New England and Mid-Atlantic prices is due to the level of pipeline expansion activity; specifically, the EIA stated:

> *Multiple pipeline expansion projects are expected to begin service this winter to increase natural gas takeaway capacity from the Appalachian Basin's Marcellus Shale play, where production has increased significantly over the past two years. These new projects are largely focused on transporting gas to the New York/New Jersey and Mid-Atlantic regions and would have limited benefit for consumers in New England, where price spikes during periods of peak winter demand appear likely to persist…The difference in construction activity for New York and New England markets is reflected in market prices for natural gas.*[100]

The benefit of additional pipeline capacity into the Mid-Atlantic region is illustrated by Table III-3. Specifically, last year (i.e., 2013/2014) the TETCO M3 to Henry Hub basis was approximately $0.85/MMBtu, compared to the ALGCG to Henry Hub basis of $3.96/MMBtu for the same period.

With respect to the next three years, the average forward basis differentials over the 2014/2015 to 2016/2017 split-years is summarized in Table III-5 below.

[100] U.S. Energy Information Administration, "Today in Energy: Marcellus natural gas pipeline projects to primarily benefit New York and New Jersey", October 30, 2013.

Table III-5: Forward Basis Differentials[101]

Split-Yr (Nov-Oct)	Winter (Nov-Mar)			Summer (Apr-Oct)			Annual (Nov-Oct)		
	TETCO M3-Henry Hub	ALGCG-Henry Hub	ALGCG-TETCO M3	TETCO M3-Henry Hub	ALGCG-Henry Hub	ALGCG-TETCO M3	TETCO M3-Henry Hub	ALGCG-Henry Hub	ALGCG-TETCO M3
2014/2015*	$ 0.70	$ 7.10	$ 6.40	$ (1.13)	$ (0.09)	$ 1.05	$ (0.37)	$ 2.91	$ 3.28
2015/2016	$ 0.64	$ 7.28	$ 6.64	$ (1.04)	$ (0.24)	$ 0.80	$ (0.34)	$ 2.90	$ 3.24
2016/2017	$ 0.64	$ 5.23	$ 4.59	$ (0.74)	$ (0.24)	$ 0.50	$ (0.17)	$ 2.04	$ 2.21
Forward Avg. (2014/15-2016/17)	**$ 0.66**	**$ 6.54**	**$ 5.88**	**$ (0.97)**	**$ (0.19)**	**$ 0.78**	**$ (0.29)**	**$ 2.61**	**$ 2.91**

* 2014/2015 calculated as average of historical Nov-2014 and Dec-2014 spot prices; and forward contracts for Jan-2015 to Mar-2015.

As shown in the forward price analysis, presented in Table III-5 above, the high winter price premiums and basis volatility in New England will likely continue until new pipeline infrastructure is added to relieve the capacity constraints. Specifically, the forward winter ALGCG to Henry Hub basis differential declines from $7.10/MMBtu in 2014/2015 and $7.28/MMBtu in 2015/2016 to $5.23/MMBtu following the expected capacity additions from Kinder Morgan's Connecticut Expansion Project and Spectra Energy's AIM Project in the winter of 2016/2017. However, the ALGCG to Henry Hub winter basis differential in 2016/2017 of $5.23/MMBtu is still significantly higher than the forward winter basis differential of $0.64/MMBtu for the adjacent market area (i.e., TETCO M3 to Henry Hub), suggesting that additional pipeline capacity into New England is needed.

[101] Source: Sussex analysis of the simple average of daily basis differentials based on historical spot prices from SNL Financial; and forward settlement prices as of December 11, 2014 from Bloomberg Professional.

IV. Demand Forecast

A. Overview

The forecast of firm customer demand and the subsequent determination of planning load requirements over the planning horizon are integral parts of the development of Northern's IRP that serve as the basis for resource decision making. Section IV of this IRP describes the forecast methodology and assumptions, reviews the development of customer segment forecasts, presents the throughput forecast under normal weather conditions, introduces the Company's design planning standards and presents design year and design day throughput forecasts over the five-year forecast horizon covering the gas years of 2015/16 through 2019/20.[102] The customer segment forecasts also provide the required breakout of forecast C&I demand into C&I Sales and Transportation, as well as the required breakout of forecast C&I Transportation demand by Capacity Assigned Transportation customers and Capacity Exempt Transportation customers.

Section V, Planning Load Forecast, documents the conversion of the design year and design day throughput forecasts into planning load requirements.

This Demand Forecast section is organized as follows:

Part B, Forecast Methodology and Summary Results, provides an overview of the forecasting process and presents Northern's system-wide (Maine and New Hampshire) customer, Design Year Throughput and Design Day Throughput forecast results;

Part C, Customer Segment Forecasts, describes the forecasting methodology, data utilized, results and analysis for each Customer Segment, including Special Contract customers, the breakout of C&I demand into the various capacity assignment categories and adjustments for energy efficiency;

Part D, Normal Year Throughput Forecast, describes the calculation of the Normal Year Throughput forecast and presents projected Normal Year Throughput for each division.

Part E, Design Year Throughput Forecast, describes Northern's design year planning standard and the calibration of the customer segment models to Design Year conditions and presents projected Design Year Throughput for each division.

Part F, Design Day Throughput Forecast, describes Northern's design day planning standard and the calculation of the Design Day Throughput forecast and presents projected Design Day Throughput for each division.

[102] A gas-year (i.e., split-year) is defined as the twelve-month period from November to October; with the winter period defined as the five months from November to March, and the summer period defined as the seven months from April to October.

Complete detail on the statistical modeling process, statistical output from all customer segment models and comprehensive documentation of the demand forecast is provided in Appendix 1, Supplemental Materials for the Demand Forecast Section.

B. Forecast Methodology and Summary Results

The long-term natural gas demand models that were developed for the 2015/16 through 2019/20 demand forecast use variables that reflect the major factors that influence natural gas demand in the Company's service territory. This section includes a description of the demand forecasting methodology, models, and Company-wide results.

This IRP uses the definitions listed in Table IV-1 below to refer to and distinguish between different types of natural gas demand.

Table IV-1: Forecast and Capacity Assignment Terminology[103]

Term	Definition
Demand, Usage, or Load	Generic terms that refer to the gas consumed by customers
Sales Demand	Demand of "Sales Service" customers who purchase gas from the Company
Transportation Demand	Demand of C&I "Transportation Service" customers who purchase gas from a retail marketer under the Delivery Service Terms and Conditions
Customer Segment Demand	Demand of a defined group of customer classes measured at the customer meter on a billing period basis
Throughput	Usage as measured at the gate station on a calendar period basis, including Demand, Company Use, Losses and Unbilled Sales
Capacity Exempt Customer	Certain Transportation Service customers who are not subject to Capacity Assignment under the Delivery Service Terms and Conditions
Capacity Assigned Customer	Certain Transportation Service customers who are subject to some form of Capacity Assignment under the Delivery Service Terms and Conditions
Design Planning Standard	Extreme cold weather conditions with a defined likelihood of occurrence during which customer demands are expected to be at their highest levels. Northern plans to a design standard with a 1 in 33 year likelihood of occurrence.

Separate sets of forecasts were developed for Northern's Maine and New Hampshire Divisions using the same processes and, to the extent possible, the same regression model specifications and then combined to establish Northern's system-wide demand. For each Division, the demand forecasts were developed at the Customer Segment level under normal weather conditions based on economic and

103 These definitions refer to firm service; Northern does not have any interruptible customers at this time.

demographic data that incorporate the major factors influencing natural gas demand in the Company's service territory, as described in more detail in the following section. Modeled Customer Segment Demand was reduced for incremental savings expected from energy efficiency programs.[104] The Company made no explicit out of model adjustments, such as for marketing efforts. Customer demand from each segment was tallied and adjusted further for Company Use, losses and unbilled sales to estimate Normal Year Throughput, which is total usage at the Company's gate stations on a calendar month basis under normal weather conditions. The results of the Customer Segment models were also calibrated to reflect design weather conditions and similarly adjusted to estimate Design Year Throughput. Lastly, the Design Day Throughput forecasts were developed.

As shown in Table IV-2, Northern's customer count is projected to increase at an average annual rate of almost 3 percent which reflects the addition of nearly 10,000 customers over the forecast period.

Table IV-2: Northern Projected Customer Counts

Split Year	Residential Customers	C&I Sales Customers	C&I Transport Customers	Northern Customers
2014/15	45,483	13,843	3,440	62,767
2015/16	47,006	14,306	3,510	64,822
2016/17	48,550	14,682	3,574	66,806
2017/18	50,115	14,983	3,628	68,727
2018/19	51,697	15,227	3,670	70,594
2019/20	53,289	15,433	3,704	72,426
CAGR	3.2%	2.2%	1.5%	2.9%

Table IV-3 presents the forecast of Northern's Design Year and Design Day Throughput, which are projected to increase at average annual rates of about 3 percent, resulting in additional throughput of approximately 3 Bcf annually and 22,000 Dth on design day.

Table IV-3: Northern Design Year and Design Day Throughput (Dth)

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	Company Use	Losses and Unbilled	Design Year Throughput	Design Day Throughput
2014/15	3,427,673	4,717,316	10,927,084	7,675	281,706	19,361,454	147,656
2015/16	3,529,064	4,814,657	11,054,783	7,675	287,422	19,693,601	150,050
2016/17	3,670,585	4,923,298	11,614,052	7,675	301,397	20,517,008	156,015
2017/18	3,828,674	5,027,661	12,265,011	7,675	317,084	21,446,105	162,759
2018/19	3,987,648	5,110,921	12,793,340	7,675	330,386	22,229,970	168,438
2019/20	4,118,394	5,147,115	12,832,082	7,675	333,997	22,439,263	169,945
CAGR	3.7%	1.8%	3.3%	0.0%	3.5%	3.0%	2.9%

104 Expected energy efficiency savings are expected reductions in customer demand associated with current energy efficiency programs and budget levels, extrapolated through the forecast period. Energy efficiency programs are funded through charges to Northern's natural gas customers.

C. Customer Segment Forecasts

1. Introduction

The Customer Segment forecasts are based on forecasts of economic and demographic conditions in the Company's Maine and New Hampshire service territories. The Customer Segment forecast was derived from separate Division-specific monthly forecast models for each of the following Customer Segments:

- Residential Heating Customers
- Residential Non-Heating Customers
- C&I Low Load Factor ("LLF")[105] Total Customers (i.e., Sales and Transportation)
- C&I High Load Factor ("HLF") Total Customers (i.e., Sales and Transportation)
- C&I Low Load Factor ("LLF") Sales Customers (i.e., excludes Transportation)
- C&I High Load Factor ("HLF") Sales Customers (i.e., excludes Transportation)
- Special Contracts (2 customers in the New Hampshire Division)

The demand forecasts for the six Residential and C&I Customer Segments are based on separate econometric models for number of customers and use per customer. Thus, in total, twelve separate Residential and C&I models were developed for each Division. In addition, a model for Special Contract customers was developed. Currently, there are no Special Contract customers in the Maine Division and there are two Special Contract customers in the New Hampshire Division. The demand forecast for each Customer Segment was determined by multiplying the forecasted results from the number of customer model by the forecasted results from the use per customer model.

In order to separately estimate C&I Sales Demand and C&I Transportation Demand, as required under the terms of the 2011 IRP Settlement, separate sets of customer segment models were estimated, using the same regression model specifications to the extent possible, to determine C&I Total customer demand and C&I Sales customers demand. C&I Transportation customer demand was then calculated as the difference between C&I Total demand and C&I Sales demand. Further, in order to separately estimate C&I Capacity Exempt Transportation Demand and C&I Capacity Transportation Demand, a separate regression model was developed for each state with the dependent variable of C&I Capacity Exempt Transportation Demand expressed as a percent of C&I Transportation Demand. The forecast of this ratio was applied to forecast C&I Transportation Demand in order to develop the forecast of C&I Capacity Exempt Transportation Demand.

The Customer Segment demand forecast models were developed using regression analysis, based on accepted statistical techniques.[106] For the Customer Segment forecasts, regression analysis

[105] In Maine, LLF (or equivalently high winter) use is defined as peak period (November through April) usage greater than or equal to 63% of annual usage. In New Hampshire, LLF (or equivalently high winter) use is defined as peak period usage greater than or equal to 67% of annual usage. See also Table IV-4.

was used to predict monthly number of customers and use per customer by Customer Segment based on predicted values of various external variables (e.g., weather, price of natural gas, employment levels, and population). The regressions used monthly frequency data, which is an improvement over the process used in Northern's 2011 IRP, which used quarterly data. Specifically, using monthly data provides more degrees of freedom, avoids averaging away consumption data detail which is collected monthly and avoids the need to reallocate quarterly results to monthly periods in order to properly report gas year results.[107] In regression analysis terms, number of customers and use per customer are the "dependent variables" and the various external variables are the "independent variables." The Customer Segment dependent variables for each Division were based on historical billing data. The Customer Segment models were estimated using dependent variable and independent variable data from January 2009 through March 2014.

All regression analysis was conducted using the EViews software package. The "Statistical Techniques and Glossary" section of Appendix 1 provides a description of the modeling process used to develop the regression models.

2. Data Description

Five general data and variable categories were used in the development of the Customer Segment forecasts; these categories are described below. The actual variables used in each customer segment regression model are defined along with each model.

a) Customer Segment Data

Historical monthly billing data were collected from Company records for each Division by customer class for the period January 2009 through March 2014, including demand, measured in therms or ccf; number of customers; and bundled revenue by rate class for each Division. This data was aggregated into the respective Customer Segments by combining customer classes with similar usage patterns. For example, the C&I Low Load Factor Customer Segment is comprised of C&I customers that are served under one of Northern's high winter use rate schedules, whereas the C&I High Load Factor Customer Segment is comprised of C&I customers that are served under one of Northern's low winter use rate schedules. The customer classes that comprise each Customer Segment for each Division are shown in the table below:

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106 Regression analysis is concerned with relating a dependent (or response) variable with a set of independent (or predictor) variables; a common use of regression analysis is to allow for predictions of the dependent variable based on predicted values of the independent variables.

107 Since the gas year begins in November, the gas year is out of sync with calendar quarters.

Table IV-4: Customer Segment Definitions

Class ME	Class NH	Class Description	Customer Segment
R-2	R-5,R-10	Residential Heating	Residential Heating
R-1	R-6,R-11	Residential Non-Heating	Residential Non-Heating
G-40	G-40	C&I Sales Low Annual Use, High Peak Period/ Winter Use	C&I Low Load Factor
G-41	G-41	C&I Sales Medium Annual Use, High Peak Period/ Winter Use	
G-42	G-42	C&I Sales High Annual Use, High Peak Period/ Winter Use	
T-40	T-40	C&I Transport Low Annual Use, High Peak Period/ Winter Use	
T-41	T-41	C&I Transport Medium Annual Use, High Peak Period/ Winter Use	
T-42	T-42	C&I Transport High Annual Use, High Peak Period/ Winter Use	
G-50	G-50	C&I Sales Low Annual Use, Low Peak Period/ Winter Use	C&I High Load Factor
G-51	G-51	C&I Sales Medium Annual Use, Low Peak Period/ Winter Use	
G-52	G-52	C&I Sales High Annual Use, Low Peak Period/ Winter Use	
T-50	T-50	C&I Transport Low Annual Use, Low Peak Period/ Winter Use	
T-51	T-51	C&I Transport Medium Annual Use, Low Peak Period/ Winter Use	
T-52	T-52	C&I Transport High Annual Use, Low Peak Period/ Winter Use	
SPC	SPC	Special Contracts	Special Contracts

b) *Weather Variables*

Historical daily effective degree day ("EDD") data for the 30 year historical period of November 1, 1983 through March 31, 2014 was utilized by the Company for the Maine Division (measured at the Portland, Maine weather station) and for the New Hampshire Division (measured at the Portsmouth, New Hampshire weather station). Daily EDD data were calculated based on averages of 24 hours of temperature and wind speed data for each Gas Day, which begins and ends at 10 AM each day.[108]

Firm natural gas demand is heavily dependent on weather conditions, as measured by EDD, which vary on a daily, monthly, and annual basis. Customer segment demand is measured on a billing month basis whereby approximately equal numbers of Northern's customer meters are read every

[108] The Company used the average temperature and wind speeds to produce daily EDD for each Gas Day for Division according to the following formula:

*If avg. temperature < 65, EDD = (65 – avg. temperature) * (1 + (avg. wind speed / 100))*

If avg. temperature > 65, EDD = 0

working day of the month. As a result, most of the consumption recorded in the first billing cycles of a billing month relates to consumption that occurred in the prior calendar month, and most of the consumption recorded in the last billing cycles of a billing month relates to consumption that occurred in the same calendar month. Thus, consumption in each billing month is affected by EDD observed in both the same month and the prior month. A billing month EDD variable was developed to align the pattern of observed daily EDD to the billing cycle pattern each month. The methodology used to calculate billing cycle monthly EDD data is illustrated in the "Calculation of Billing Cycle EDD Variable" section of Appendix 1.

Historical billing cycle monthly EDD values for the period January 2009 through March 2014 were calculated and used to measure the effect of temperature on natural gas use in the Customer Segment use per customer regression models.[109] Historical EDD values were also used to develop normal year and design year EDD patterns, as well as design day EDD levels, for each Division. The normal year and design year EDD were applied to the customer segment models to estimate normal year and design year demand. These EDD patterns are described further and presented in the Normal Year Throughput and Design Year Throughput sections that follow.

c) Economic and Demographic Variables

Economic activity and demographic data to be used in the regression analysis were acquired from IHS Global Insight, Inc. ("Global Insight"). Global Insight provided separate data series for the Maine and New Hampshire Divisions. Historical data was obtained for the period of January 2009 through March 2014 (the "historical period") and forecast data was provided from April 2014 through October 2040. The data include fuel prices, employment, income, population, and housing statistics specific to counties that Northern serves in Maine and New Hampshire, as well as state level data for Maine and New Hampshire. The Maine Division variables are derived from data for the Lewiston-Auburn and Portland-South Portland metropolitan areas since these areas correspond most closely to Northern's Maine service territory. The New Hampshire Division variables were derived from data for Rockingham County and Strafford County since these counties most closely correspond to Northern's New Hampshire service territory. Table IV-5 summarizes the Global Insight economic and demographic data evaluated while developing the Customer Segment models.

[109] The dependent variable in these use per customer models was actual (rather than weather normalized) use per customer.

Table IV-5: Global Insight Variables

Lewiston-Auburn and Portland- South Portland metropolitan areas for Maine Division:
Rockingham and Strafford Counties for New Hampshire Division:
Total Population (Thousands)
Households (Thousands)
Housing Stock (Units)
Housing Starts, Total Private
Employment, Total Non-farm (Thousands)
Employment, Non-manufacturing (Thousands)
Employment, Total Service Providing Private Employment (Thousands)
Employment, Manufacturing (Thousands)
State of Maine and State of New Hampshire:
Average Retail Price of Natural Gas, Residential ($/MMBtu)
Average Retail Price of Natural Gas, Commercial, ($/MMBtu)
Average Retail Price of Natural Gas, Industrial, ($/MMBtu)

d) Natural Gas Price Variable

Because economic theory suggests that price is likely to influence demand, natural gas price variables specific to each Customer Segment were developed for the use per customer models. Historical natural gas prices for each Customer Segment and each Division were derived from Company billing data. Forecasted prices, also specific to each Customer Segment and each Division, were developed using price forecasts prepared by Global Insight, together with the Company historical data. The methodology used to develop the natural gas price variables is described in "Calculation of Natural Gas Price Variables" in Appendix 1.

e) Other Variables

The following adjustments were made, and additional variables were developed, for use in the Customer Segment models:

- Monthly indicator or trend variables were created to account for any systematic changes in the number of customers or use per customer that were a function of time.
- Dummy variables (or indicator variables) were created to represent time-related events. These time-related dummy variables equal 1 when that specific time-related event occurs, and equal 0 at other times.
- Interactive variables were created by multiplying dummy variables and selected independent variables to determine if the relationships between the dependent variable and the selected independent variables changed as a result of time-related events.

- Variables with time lags were created from several of the data series to test whether the impact of that variable on the number of customers or use per customer was not immediate, but instead is delayed.

3. Customer Segment Model Results – Maine Division

This section summarizes the forecast results for each Customer Segment model for Northern's Maine Division, including the buildup of customer demand by segment and ultimately total demand for the Maine Division. Detailed statistical documentation including: (a) regression model output; (b) definitions of all variables used; (c) historical actual values, historical fitted values derived from each model and model residuals; and (d) the results of the statistical tests that were performed for each Customer Segment model are provided in Appendix 1.

The customer segment model results are presented as follows for the Maine Division, in this Section IV.C.3, and for the New Hampshire Division in the following Section IV.C.4.

Table IV-6: Structure of Customer Segment Model Results Section

Sub-Section	Description
a) Residential Heating	Customer Model results times Use per Customer results
b) Residential Non-Heating	Customer Model results times Use per Customer results
c) Residential Demand	Equals Residential Heating + Residential Non Heating - EE
d) C&I Low Load Factor (LLF) Total	Customer Model results times Use per Customer results
e) C&I High Load Factor (HLF) Total	Customer Model results times Use per Customer results
f) Special Contracts (SC)	Results of Customer-specific Models
g) C&I Total Demand	Equals C&I LLF Total + C&I HLF Total + SC - EE
h) C&I LLF Sales	Customer Model results times Use per Customer results
i) C&I HLF Sales	Customer Model results times Use per Customer results
j) C&I Sales Demand	Equals C&I LLF Sales + C&I HLF Sales + SC - EE
k) C&I Transportation Demand	Equals C&I Total Demand - C&I Sales Demand
l) Cap Assigned v. Cap Exempt	Ratio of Assigned v. Exempt Transportation Customers
m) Energy Efficiency (EE)	Summary of EE by Customer Segment
n) Customer Segment Demand	Equals Residential + C&I Sales + C&I Transportation

a) *Residential Heating Customer Segment Forecast – Maine Division*

Residential Heating is the Maine Division's largest Customer Segment in terms of number of customers, but is only about half as large as the C&I HLF segment and only about one-fifth as large as the C&I LLF segment in terms of demand. In the final regression equation that was selected to predict Residential Heating customers, total population was statistically significant. In the final regression equation that was selected to predict Residential Heating use per customer, billing cycle EDD and the price of natural gas were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-7 below summarizes the Residential Heating customer segment model results for customer growth, use per customer, and residential heating demand for the forecast period as compared to the historical reference period.[110]

Table IV-7: Residential Heating Customer Segment Forecast – Maine Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	13,711	75	1,030,102
2010/11	14,206	76	1,082,756
2011/12	14,720	77	1,126,696
2012/13	15,250	77	1,166,762
2013/14	16,046	81	1,305,588
CAGR	4.0%	2.0%	6.1%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	17,111	82	1,402,732
2015/16	18,186	83	1,506,179
2016/17	19,263	85	1,638,217
2017/18	20,348	88	1,782,598
2018/19	21,438	90	1,927,300
2019/20	22,536	91	2,049,988
CAGR	5.7%	2.1%	7.9%

Over the forecast period, the number of Maine Residential Heating customers is expected to grow at an annual rate of 5.7% compared to a growth rate of 4.0% over the historical reference period. Use per customer for the Residential Heating Customer Segment is expected to increase by 2.1% annually which is effectivity the same as the historical reference period rate of 2.0%. The Residential Heating demand forecast was calculated by multiplying the forecasted number of Residential Heating

[110] Throughout the demand forecast section, historical and forecast data are provided along with compound annual growth rates ("CAGR"), which are calculated as the value in the final year divided by the value in the initial year raised to the power of 1 divided by the number of years in the period minus one.

customers each month by the forecasted Residential Heating use per customer for that month. Over the forecast period, Residential Heating demand is expected to increase at a slightly higher rate than over the historical reference period. These results appear reasonable given the information available.

b) Residential Non-Heating Customer Segment Forecast – Maine Division

The Maine Residential Non-Heating customer segment has about one fourth as many customers as the Residential Heating segment, but only about one-tenth of the demand, making it the smallest segment in terms of demand. In the final regression equation that was selected to predict Residential Non-Heating customers, Total Housing Starts was statistically significant. In the final regression equation that was selected to predict Residential Non-Heating use per customer, Bill Cycle EDD was statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-8 below summarizes the Residential Non-Heating customer model results for customer growth, use per customer, and residential non-heating demand for the forecast period as compared to the historical reference period.

Table IV-8: Residential Non-Heating Customer Segment Forecast – Maine Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	4,957	19	95,696
2010/11	4,905	21	101,185
2011/12	4,761	24	115,222
2012/13	4,486	28	124,356
2013/14	4,282	29	124,607
CAGR	-3.6%	10.8%	6.8%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	4,239	29	124,189
2015/16	4,168	30	124,433
2016/17	4,100	30	124,125
2017/18	4,036	31	123,522
2018/19	3,978	31	122,822
2019/20	3,927	31	122,194
CAGR	-1.5%	1.2%	-0.3%

Over the forecast period, the number of Maine Residential Non-Heating customers is projected to decline by -1.5% annually compared to the declining growth rate of -3.6% over the historical reference period. Use per customer for the Residential Non-Heating Customer Segment is projected to grow by 1.2% annually over the forecast period, which is a significant decrease in growth compared to the 10.8% increase in usage per customer over the historical reference period, but the forecast use per customer is consistent with the most recent two years of billed sales history. The Residential Non-Heating demand forecast was calculated by multiplying the forecasted number of Non-Residential Heating customers for each month by the forecasted Residential Non-Heating use per customer for that month. Over the forecast period, Residential Non-Heating demand is expected to remain essentially flat, which is a reduction in demand growth relative to the historical reference period, but is consistent with the trends observed during the most recent years of the historical period. These results appear reasonable given the information available.

c) Residential Customer Segment Demand – Maine Division

Residential demand for the Maine Division is summarized in Table IV-9 below as the sum of the Residential Heating customer segment demand and the Residential Non-Heating customer segment demand less expected residential energy efficiency savings ("EE Savings"). Residential demand is projected to increase by 6 percent annually over the forecast period. As highlighted above, the primary driver of residential customer growth is total population growth and the primary drivers of residential use per customer are price and weather.

Table IV-9: Residential Customer Segment Demand (Dth) - Maine Division

Split Year	Residential Heating Demand	Residential Non-Heating Demand	Residential EE Savings	Residential Demand
2014/15	1,402,732	124,189	-24,907	1,502,014
2015/16	1,506,179	124,433	-50,196	1,580,416
2016/17	1,638,217	124,125	-75,573	1,686,769
2017/18	1,782,598	123,522	-100,950	1,805,170
2018/19	1,927,300	122,822	-126,327	1,923,796
2019/20	2,049,988	122,194	-151,704	2,020,478
CAGR	7.9%	-0.3%	43.5%	6.1%

d) C&I Low Load Factor Total Customer Segment Forecast – Maine Division

The C&I LLF Total Customer Segment is the Maine Division's second largest Customer Segment in terms of number of customers, with about half as many customers as the Residential Heating segment, and by far the largest Customer Segment in terms of demand. C&I LLF demand is greater than all other segments combined. In the final regression equation that was selected to predict C&I LLF Total customers, a trend variable and Non-Manufacturing Employment were statistically significant. In the final regression equation that was selected to predict C&I LLF Total use per customer, Bill Cycle EDD and the LLF Price of Natural Gas were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-10 below summarizes the C&I LLF Total customer model results for customer growth, use per customer, and C&I LLF Total demand for the forecast period as compared to the historical reference period.

Table IV-10: C&I LLF Total Customer Segment Forecast – Maine Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	5,985	830	4,969,495
2010/11	6,101	851	5,192,275
2011/12	6,527	815	5,318,817
2012/13	7,523	750	5,644,258
2013/14	8,395	773	6,492,280
CAGR	8.8%	-1.8%	6.9%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	8,879	808	7,175,751
2015/16	9,268	793	7,346,877
2016/17	9,579	809	7,745,925
2017/18	9,838	832	8,184,398
2018/19	10,059	849	8,541,243
2019/20	10,253	838	8,595,177
CAGR	2.9%	0.7%	3.7%

Over the forecast period, the number of Maine C&I LLF Total customers is projected to increase by 2.9% annually compared to the growth rate of 8.8% over the historical reference period. Use per customer for the C&I LLF Total Customer Segment is expected to grow by 0.7% annually over the forecast period compared to the declining growth rate of -1.8% over the historical reference period. The C&I LLF Total Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I LLF Total customers each month by the forecasted C&I LLF Total use per customer for that month. Over the forecast period, C&I LLF Total demand is expected to increase by almost 4 percent, which is slower than growth seen in the historical reference period and is driven by a declining rate of growth in customer additions. These results appear reasonable given the information available.

e) C&I High Load Factor Total Customer Segment Forecast – Maine Division

The Maine C&I HLF Total Customer Segment encompasses about 20 percent as many customers as the C&I LLF segment. The C&I HLF segment consumes about 40 percent of the gas demand of the C&I LLF segment and about twice as much as the Residential Heating segment. In the final regression equation that was selected to predict C&I HLF Total customers, Manufacturing Employment was statistically significant. In the final regression equation that was selected to predict C&I HLF Total use per customer, Bill Cycle EDD and the HLF Natural Gas Price were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-11 below summarizes the C&I HLF Total customer model results for customer growth, use per customer, and C&I HLF Total demand for the forecast period as compared to the historical reference period.

Table IV-11: C&I HLF Total Customer Segment Forecast – Maine Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	1,859	1,174	2,182,326
2010/11	1,795	1,366	2,452,267
2011/12	1,729	1,519	2,626,172
2012/13	1,527	1,689	2,578,620
2013/14	1,603	1,710	2,740,808
CAGR	-3.6%	9.9%	5.9%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	1,609	1,747	2,810,209
2015/16	1,615	1,759	2,840,551
2016/17	1,617	1,859	3,005,378
2017/18	1,616	1,980	3,199,365
2018/19	1,615	2,084	3,366,334
2019/20	1,614	2,110	3,405,473
CAGR	0.1%	3.9%	3.9%

Over the forecast period, the number of Maine C&I HLF Total customers is projected to effectively remain unchanged. This stable customer forecast compares favorably to the declining annual growth rate of -3.6% experienced over the historical reference period. Use per customer for the C&I HLF Total Customer Segment is expected to grow by 3.9% annually over the forecast period compared to a 5.9% growth rate over the historical reference period. The C&I HLF Total Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I HLF Total customers each month by the forecasted C&I HLF Total use per customer for that month. Over the forecast period, C&I HLF Total demand growth is expected to increase at an average annual rate of about 4 percent, which moderately slower than the growth rate seen in the historical reference period and is driven by a slower rate of growth in use per customer. These results appear reasonable given the information available.

f) Special Contract Demand – Maine Division

There are currently no Special Contract customers in the Maine Division.

g) C&I Total Customer Segment Demand – Maine Division

C&I Total demand for the Maine Division is summarized in Table IV-12 below as the sum of the C&I LLF Total customer segment demand and the C&I HLF Total customer segment demand less expected C&I Total energy efficiency savings. C&I Total Demand is projected to increase by 3.5% annually over the forecast period.

Table IV-12: C&I Total Customer Segment Demand (Dth) - Maine Division

Split Year	C&I LLF Total Demand	C&I HLF Total Demand	Special Contract Total Demand	C&I Total EE Savings	C&I Total Demand
2014/15	7,175,751	2,810,209	0	-28,946	9,957,015
2015/16	7,346,877	2,840,551	0	-58,335	10,129,093
2016/17	7,745,925	3,005,378	0	-87,826	10,663,477
2017/18	8,184,398	3,199,365	0	-117,317	11,266,446
2018/19	8,541,243	3,366,334	0	-146,808	11,760,769
2019/20	8,595,177	3,405,473	0	-176,299	11,824,351
CAGR	3.7%	3.9%	n/a	43.5%	3.5%

h) C&I Low Load Factor Sales Customer Segment Forecast – Maine Division

The Maine C&I LLF Sales Customer Segment is the subset of C&I LLF customers who received sales service over the historical period. In the final regression equation that was selected to predict C&I LLF Sales customers, which was consistent with the model selected to predict C&I LLF Total customers, a trend variable was statistically significant. In the final regression equation that was selected to predict C&I LLF Sales use per customer, which was similar to the model selected to predict C&I LLF Total use per customer, Bill Cycle EDD and the LLF Natural Gas Price were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-13 below summarizes the C&I LLF Sales customer model results for customer growth, use per customer, and C&I LLF Sales demand for the forecast period as compared to the historical reference period.

Table IV-13: C&I LLF Sales Customer Segment Forecast – Maine Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	4,851	335	1,625,964
2010/11	4,829	334	1,610,722
2011/12	4,954	323	1,601,511
2012/13	5,572	304	1,692,854
2013/14	6,485	318	2,060,990
CAGR	7.5%	-1.3%	6.1%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	6,949	318	2,213,112
2015/16	7,331	319	2,336,045
2016/17	7,636	319	2,437,616
2017/18	7,890	320	2,524,267
2018/19	8,108	321	2,598,855
2019/20	8,298	321	2,660,582
CAGR	3.6%	0.1%	3.8%

Over the forecast period, the number of Maine C&I LLF Sales customers is projected to increase by 3.6% annually compared to a 7.5% growth rate over the historical reference period. Use per customer for the C&I LLF Sales Customer Segment is expected to remain flat over the forecast period after declining slightly over the historical reference period. The C&I LLF Sales Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I LLF Sales customers each month by the forecasted C&I LLF Sales use per customer for that month. Over the forecast period, C&I LLF Sales demand is expected to increase by almost 4 percent annually, which is moderately slower than the rate of growth seen in the historical reference period and is driven by a declining rate of growth in customer additions. These results are similar to the C&I LLF Total forecast results and appear reasonable given the information available.

i) C&I High Load Factor Sales Customer Segment Forecast – Maine Division

The Maine C&I HLF Sales Customer Segment is the subset of C&I HLF customers who received sales service over the historical period. In the final regression equation that was selected to predict C&I HLF Sales customers, which was consistent with the model selected to predict C&I HLF Total customers, Manufacturing Employment was statistically significant. In the final regression equation that was selected to predict C&I HLF Sales use per customer, which was similar to the model selected to predict C&I HLF Total use per customer, Bill Cycle EDD and the HLF Natural Gas Price were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-14 below summarizes the C&I HLF Sales customer model results for customer growth, use per customer, and C&I HLF Sales demand for the forecast period as compared to the historical reference period.

Table IV-14: C&I HLF Sales Customer Segment Forecast – Maine Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	1,525	250	382,060
2010/11	1,440	288	414,318
2011/12	1,337	296	395,761
2012/13	1,179	268	316,438
2013/14	1,261	322	405,598
CAGR	-4.6%	6.5%	1.5%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	1,278	297	379,538
2015/16	1,291	297	383,056
2016/17	1,294	297	384,400
2017/18	1,293	297	384,294
2018/19	1,292	298	384,350
2019/20	1,289	298	383,467
CAGR	0.2%	0.0%	0.2%

Over the forecast period, the number of Maine C&I Sales HLF customers is projected to effectively remain unchanged with a slight increase of 0.2% annually compared to a historical period declining rate of -4.6%. Use per customer for the C&I HLF Sales Customer Segment is expected to remain unchanged over the forecast period compared to an annual growth rate of 6.5% over the historical reference period. The forecast use per customer reflects a return to average consumption levels for these customers seen over the last four years of the historical period. The C&I HLF Sales Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I HLF Sales customers each month by the forecasted C&I HLF Sales use per customer for that month. Over the forecast period, C&I HLF Sales demand is expected to essentially remain flat, which reflects a slowdown in demand growth relative to the historical reference period. These results are similar to the C&I HLF Total forecast results and appear reasonable given the information available.

j) C&I Sales Customer Segment Demand – Maine Division

C&I Sales demand for the Maine Division is summarized in Table IV-15 below as the sum of the C&I LLF Sales customer segment demand and the C&I HLF Sales customer segment demand less expected C&I Sales energy efficiency savings. C&I Sales demand is projected to increase by 3 percent over the forecast period.

Table IV-15: C&I Sales Customer Segment Demand (Dth) - Maine Division

Split Year	C&I LLF Sales Demand	C&I HLF Sales Demand	Special Contract Sales Demand	C&I Sales EE Savings	C&I Sales Demand
2014/15	2,213,112	379,538	0	-8,927	2,583,723
2015/16	2,336,045	383,056	0	-18,548	2,700,552
2016/17	2,437,616	384,400	0	-27,638	2,794,378
2017/18	2,524,267	384,294	0	-36,183	2,872,379
2018/19	2,598,855	384,350	0	-44,669	2,938,536
2019/20	2,660,582	383,467	0	-54,572	2,989,477
CAGR	3.8%	0.2%	n/a	43.6%	3.0%

k) C&I <u>Transportation</u> Customer Segment Demand – Maine Division

C&I Transportation customer segment demand is the portion of C&I Total customer segment demand from customers who received transportation service over the historical period. C&I Transportation demand was calculated by subtracting C&I Sales demand from C&I Total demand for each customer segment. C&I Transportation demand for the Maine Division is summarized in Table IV-16 below as the sum of C&I LLF Transportation demand and C&I HLF Transportation demand less expected C&I Transportation energy efficiency savings. C&I Transportation demand is projected to increase by 3.7 percent annually over the forecast period.

Table IV-16: C&I Transportation Customer Segment Demand (Dth) - Maine Division

Split Year	C&I LLF Transport Demand	C&I HLF Transport Demand	Special Contract Transport Demand	C&I Transport EE Savings	C&I Transport Demand
2014/15	4,962,639	2,430,671	0	-20,018	7,373,291
2015/16	5,010,833	2,457,495	0	-39,786	7,428,541
2016/17	5,308,309	2,620,979	0	-60,187	7,869,100
2017/18	5,660,131	2,815,070	0	-81,133	8,394,068
2018/19	5,942,387	2,981,984	0	-102,138	8,822,232
2019/20	5,934,595	3,022,006	0	-121,727	8,834,874
CAGR	3.6%	4.5%	n/a	43.5%	3.7%

l) Capacity Assigned v. Capacity Exempt Transportation – Maine Division

In order to separately estimate Capacity Exempt and Capacity Assigned C&I Transportation Demand, the Company produced a regression model for Capacity Exempt Demand expressed as a percentage of Total C&I Transportation Demand. Table IV-17 below summarizes the Capacity Exempt and Capacity Assigned demand for the forecast period. The final model, which is provided in Appendix 1, demonstrates excellent goodness of fit and passes all statistical tests applied.

Table IV-17: Capacity Assigned v. Capacity Exempt Demand (Dth) - Maine Division

Split Year	C&I Transport Capacity Assigned	C&I Transport Capacity Exempt	C&I Transport Demand
2014/15	5,759,736	1,613,555	7,373,291
2015/16	5,681,087	1,747,454	7,428,541
2016/17	5,886,261	1,982,839	7,869,100
2017/18	6,139,479	2,254,589	8,394,068
2018/19	6,308,485	2,513,747	8,822,232
2019/20	6,176,928	2,657,946	8,834,874
CAGR	1.4%	10.5%	3.7%

m) Incremental Energy Efficiency Savings – Maine Division

An out-of-model adjustment was made to reduce the demand forecast for expected incremental savings associated with existing energy efficiency programs. The Company prepared incremental energy savings estimates associated with current Residential and C&I energy efficiency programs for the forecast period for the Maine Division. Since historical energy efficiency savings are already reflected in metered consumption, Northern defined the twelve month period ending March 2014 as the base period and calculated incremental efficiency savings by netting the estimated savings for this base period from future projected savings. Table IV-18 below provides the cumulative energy efficiency savings that are incremental to the base period for each year of the forecast period. These EE Savings were deducted from the Customer Segment demand forecasts as shown in the customer segment demand tables presented above.

Table IV-18: Incremental Energy Efficiency Savings (Dth) - Maine Division

Split Year	Residential EE Savings	C&I EE Savings	Total EE Savings
2014/15	-24,907	-28,946	-53,853
2015/16	-50,196	-58,335	-108,531
2016/17	-75,573	-87,826	-163,399
2017/18	-100,950	-117,317	-218,267
2018/19	-126,327	-146,808	-273,135
2019/20	-151,704	-176,299	-328,003
CAGR	43.5%	43.5%	43.5%

n) Customer Segment Demand Forecast Results – Maine Division

The result of the Maine Division customer segment modeling is presented below in Table IV-19, where the demand determined by customer segment assuming normal weather is tallied for the entire Division.

Table IV-19: Total Customer Segment Demand (Dth) - Maine Division

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	Customer Segment Total Demand
2014/15	1,502,014	2,583,723	7,373,291	11,459,029
2015/16	1,580,416	2,700,552	7,428,541	11,709,510
2016/17	1,686,769	2,794,378	7,869,100	12,350,247
2017/18	1,805,170	2,872,379	8,394,068	13,071,616
2018/19	1,923,796	2,938,536	8,822,232	13,684,564
2019/20	2,020,478	2,989,477	8,834,874	13,844,829
CAGR	6.1%	3.0%	3.7%	3.9%

4. Customer Segment Model Results – New Hampshire Division

This section summarizes the forecast results for each Customer Segment model for Northern's New Hampshire Division, including the buildup of customer demand by segment and ultimately total demand for the New Hampshire Division. Detailed statistical documentation including: (a) regression model output; (b) definitions of all variables used; (c) historical actual values, historical fitted values derived from each model and model residuals; and (d) the results of the statistical tests that were performed for each Customer Segment model are provided in Appendix 1. The regression models utilized to estimate customer segment demand for the New Hampshire Division were very similar to the models used to estimate customer segment demand for the Maine Division.

a) Residential Heating Customer Segment Forecast – New Hampshire Division

Residential Heating is the New Hampshire Division's largest Customer Segment in terms of number of customers, but is smaller than both the C&I LLF and C&I HLF segments in terms of demand. In the final regression equation that was selected to predict Residential Heating customers, Total Population and a trend variable were statistically significant. In the final regression equation that was selected to predict Residential Heating use per customer, Bill Cycle EDD and the Residential Heating Natural Gas Price were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-20 below summarizes the Residential Heating customer model results for customer growth, use per customer, and residential heating demand for the forecast period as compared to the historical reference period.

Table IV-20: Residential Heating Customer Segment Forecast – New Hampshire Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	20,292	79	1,605,180
2010/11	20,547	79	1,614,728
2011/12	21,020	76	1,603,666
2012/13	21,603	75	1,612,441
2013/14	22,081	78	1,732,040
CAGR	2.1%	-0.2%	1.9%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	22,564	77	1,739,354
2015/16	23,079	77	1,776,940
2016/17	23,608	77	1,820,664
2017/18	24,145	77	1,867,526
2018/19	24,686	78	1,914,621
2019/20	25,224	78	1,955,561
CAGR	2.3%	0.1%	2.4%

Over the forecast period, the number of New Hampshire Residential Heating customers is expected to grow at a rate of 2.3% annually which is consistent with the 2.1% growth rate observed over the historical reference period. Use per customer for the Residential Heating Customer Segment is expected to remain relatively flat over the forecast period, which again is consistent with the growth rate observed over the historical reference period. The Residential Heating demand forecast was calculated by multiplying the forecasted number of Residential Heating customers each month by the forecasted Residential Heating use per customer for that month. Over the forecast period, Residential Heating demand is expected to increase at a slightly higher rate than over the historical reference period. These results appear reasonable given the information available.

b) Residential Non-Heating Customer Segment Forecast – New Hampshire Division

Residential Non-Heating is the New Hampshire Division's smallest Customer Segment in terms of demand and comprises about 7 percent as many customers as the Residential Heating segment. In the final regression equation that was selected to predict Residential Non-Heating customers, Total Population was statistically significant. In the final regression equation that was selected to predict Residential Non-Heating use per customer, Bill Cycle EDD and the Residential Heating Natural Gas Price were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-21 below summarizes the Residential Non-Heating customer model results for customer growth, use per customer, and residential heating demand for the forecast period as compared to the historical reference period.

Table IV-21: Residential Non-Heating Customer Segment Forecast – New Hampshire Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	1,657	21	35,398
2010/11	1,628	23	37,194
2011/12	1,550	24	37,540
2012/13	1,505	22	33,308
2013/14	1,569	19	29,056
CAGR	-1.4%	-3.5%	-4.8%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	1,569	17	26,304
2015/16	1,573	15	23,706
2016/17	1,579	16	25,196
2017/18	1,586	17	27,744
2018/19	1,594	19	29,651
2019/20	1,602	18	28,159
CAGR	0.4%	0.9%	1.4%

Over the forecast period, the number of New Hampshire Residential Non-Heating customers is projected grow at a flat rate of 0.4% annually compared to a declining growth rate of -1.4% over the historical reference period. Residential Non-Heating use per customer is projected to grow at an annual rate of 0.9% over the forecast period compared to a declining growth rate of -3.5% over the historical reference period. The Residential Non-Heating demand forecast was calculated by multiplying the forecasted number of Residential Non-Heating customers each month by the forecasted Non-Residential Heating use per customer for that month. Over the forecast period, Residential Non-Heating demand is projected to increase by 1.4% annually, which is an increase relative to the declining growth rate observed during the historical reference period, and is driven by more stable use per customer. These results appear reasonable given the information available.

c) Residential Customer Segment Demand – New Hampshire Division

Residential demand for the New Hampshire Division is summarized in Table IV-22 below as the sum of the Residential Heating customer segment demand and the Residential Non-Heating customer segment demand less expected residential energy efficiency savings. Residential demand is projected to increase by 1.7% annually over the planning period. As highlighted above, the primary drivers of residential demand are weather and the price of natural gas.

Table IV-22: Residential Customer Segment Demand (Dth) - New Hampshire Division

Split Year	Residential Heating Demand	Residential Non-Heating Demand	Residential EE Savings	Residential Demand
2014/15	1,739,354	26,304	-14,516	1,751,143
2015/16	1,776,940	23,706	-29,319	1,771,327
2016/17	1,820,664	25,196	-44,123	1,801,737
2017/18	1,867,526	27,744	-58,786	1,836,484
2018/19	1,914,621	29,651	-72,543	1,871,730
2019/20	1,955,561	28,159	-83,159	1,900,560
CAGR	2.4%	1.4%	41.8%	1.7%

d) C&I Low Load Factor <u>Total</u> Customer Segment Forecast – New Hampshire Division

The C&I LLF Total Customer Segment is the New Hampshire Division's largest Customer Segment in terms of demand and comprises about five times larger than the C&I HLF segment in terms of customers. In the final regression equation that was selected to predict C&I LLF Total customers, Non-Manufacturing Employment was statistically significant. In the final regression equation that was used to predict C&I LLF Total use per customer, Bill Cycle EDD and the LLF Price of Natural Gas were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-23 below summarizes the C&I LLF Total customer model results for customer growth, use per customer, and C&I LLF Total demand for the forecast period as compared to the historical reference period.

Table IV-23: C&I LLF Total Customer Segment Forecast – New Hampshire Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	5,010	513	2,570,746
2010/11	5,060	505	2,556,306
2011/12	5,192	484	2,513,268
2012/13	5,339	487	2,601,951
2013/14	5,473	517	2,827,539
CAGR	2.2%	0.2%	2.4%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	5,590	505	2,820,805
2015/16	5,715	502	2,868,062
2016/17	5,834	504	2,938,873
2017/18	5,925	508	3,009,703
2018/19	5,986	512	3,063,798
2019/20	6,037	511	3,087,797
CAGR	1.6%	0.3%	1.8%

Over the forecast period, the number of New Hampshire C&I LLF Total customers is projected to increase by 1.6% annually compared to the 2.2% annual growth rate over the historical reference period. Use per customer for the C&I LLF Total Customer Segment is expected to grow by 0.3% annually which is effectivity unchanged from the 0.2% growth rate over the historical reference period. The C&I LLF Total Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I LLF Total customers each month by the forecasted C&I LLF Total use per customer for that month. Over the forecast period, C&I LLF Total demand is expected to increase by 1.8% annually, driven primarily by continued customer growth, resulting in a moderate decline in demand growth relative to the historical reference period. These results appear reasonable given the information available.

e) C&I High Load Factor Total Customer Segment Forecast – New Hampshire Division

The New Hampshire C&I HLF Total Customer Segment has about one fifth as many customers as the C&I LLF segment, but accounts for about three quarters as much demand as the C&I LLF segment. In the final regression equation that was selected to predict C&I HLF Total customers, Manufacturing Employment was statistically significant. In the final regression equation that was used to predict C&I HLF Total use per customer, Bill Cycle EDD and the HLF Price of Natural Gas were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table III-24 below summarizes the C&I HLF Total customer model results for customer growth, use per customer, and C&I HLF Total demand for the forecast period as compared to the historical reference period.

Table IV-24: C&I HLF Total Customer Segment Forecast – New Hampshire Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	1,238	1,405	1,739,458
2010/11	1,226	1,531	1,876,588
2011/12	1,204	1,618	1,948,693
2012/13	1,154	1,788	2,063,074
2013/14	1,179	1,804	2,127,076
CAGR	-1.2%	6.5%	5.2%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	1,206	1,803	2,173,839
2015/16	1,217	1,817	2,212,397
2016/17	1,226	1,884	2,310,516
2017/18	1,233	1,961	2,417,006
2018/19	1,236	2,025	2,503,080
2019/20	1,234	2,037	2,512,569
CAGR	0.5%	2.5%	2.9%

Over the forecast period, the number of New Hampshire C&I HLF Total customers is projected to increase slightly by 0.5% annually compared to a negative annual growth rate of -1.2% over the historical reference period. Use per customer for the C&I HLF Total Customer Segment is expected to grow by 2.5% annually over the forecast period compared to 6.5% over this historical reference period. The C&I HLF Total Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I HLF Total customers each month by the forecasted C&I Total HLF use per customer for that month. Over the forecast period, C&I HLF Total customer demand is expected to increase by about 3 percent annually, which is a moderate decline in demand growth relative to the historical reference period. These results appear reasonable given the information available.

f) Special Contracts – New Hampshire Division

The Special Contract Customer Segment for the New Hampshire Division is comprised of two customers. A single model was estimated to forecast Special Contract demand. In the final regression equation selected, the HLF Price of Natural Gas and a Linear Trend were statistically significant. The final model, which is provided in Appendix 1, demonstrates excellent goodness of fit and pass all statistical tests applied.

Over the forecast period, Special Contract demand is expected to grow at an annual rate of 0.4% as shown in Table IV-25 below.

Table IV-25: Special Contract Demand Forecast – New Hampshire Division

Split Year	Demand Normal Year Historical (Dth)
2009/10	105,273
2010/11	94,394
2011/12	100,706
2012/13	102,839
2013/14	108,874
CAGR	0.8%
Split Year	Demand Normal Year Forecast (Dth)
2014/15	107,661
2015/16	104,401
2016/17	102,174
2017/18	104,412
2018/19	107,634
2019/20	109,995
CAGR	0.4%

These New Hampshire Division Special Contract customers are both transportation service customers and therefore the estimated loads are added to C&I Transportation demand as shown in Table IV-30.

g) C&I Total Customer Segment Demand – New Hampshire Division

C&I Total demand for the New Hampshire Division is summarized in Table IV-26 below as the sum of the C&I LLF Total customer segment demand and the C&I HLF Total customer segment demand less expected C&I Total energy efficiency savings. C&I Total Demand is projected to increase by 1.6% annually over the forecast period.

Table IV-26: C&I Total Customer Segment Demand (Dth) - New Hampshire Division

Split Year	C&I LLF Total Demand	C&I HLF Total Demand	Special Contract Total Demand	C&I Total EE Savings	C&I Total Demand
2014/15	2,820,805	2,173,839	107,661	-44,006	5,058,299
2015/16	2,868,062	2,212,397	104,401	-88,999	5,095,861
2016/17	2,938,873	2,310,516	102,174	-137,577	5,213,987
2017/18	3,009,703	2,417,006	104,412	-177,345	5,353,776
2018/19	3,063,798	2,503,080	107,634	-213,444	5,461,068
2019/20	3,087,797	2,512,569	109,995	-245,653	5,464,709
CAGR	1.8%	2.9%	0.4%	41.0%	1.6%

h) *C&I Low Load Factor Sales Customer Segment Forecast – New Hampshire Division*

The New Hampshire C&I LLF Sales Customer Segment is the subset of C&I LLF customers who received sales service over the historical period. In the final regression equation that was selected to predict C&I LLF Sales customers, which was consistent with the model selected to predict C&I LLF Total customers, Non-Manufacturing Employment was statistically significant. In the final regression equation that was selected to predict C&I Sales LLF use per customer, Bill Cycle EDD and the LLF Natural Gas Price were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-27 below summarizes the C&I Sales LLF customer model results for customer growth, use per customer, and C&I LLF Sales demand for the forecast period as compared to the historical reference period.

Table IV-27: C&I LLF Sales Customer Segment Forecast – New Hampshire Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	4,527	339	1,532,490
2010/11	4,521	323	1,459,302
2011/12	4,514	307	1,385,968
2012/13	4,524	303	1,372,156
2013/14	4,620	341	1,573,194
CAGR	0.5%	0.1%	0.7%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	4,700	326	1,532,287
2015/16	4,776	323	1,542,710
2016/17	4,851	325	1,575,563
2017/18	4,907	329	1,613,279
2018/19	4,941	333	1,642,936
2019/20	4,969	332	1,650,768
CAGR	1.1%	0.4%	1.5%

Over the forecast period, the number of New Hampshire C&I LLF Sales customers is projected to increase at an average annual rate of 1.1% compared to the rate of 0.5% over the historical reference period. Use per customer for the C&I LLF Sales Customer Segment is expected to remain relatively flat, which is consistent with the historical reference period. The C&I LLF Sales Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I LLF Sales customers each month by the forecasted C&I Sales LLF use per customer for that month. Over the forecast period, C&I LLF Sales demand is expected to increase annually by 1.5%, driven primarily by customer growth, which would be an increase relative to historical reference period growth. These results appear reasonable given the information available.

i) C&I High Load Factor Sales Customer Segment Forecast – New Hampshire Division

The New Hampshire C&I HLF Sales Customer Segment is the subset of C&I HLF customers who received sales service over the historical period. In the final regression equation that was selected to predict C&I HLF customers, which was consistent with the model selected to predict C&I HLF Total customers, Manufacturing Employment was statistically significant. In the final regression equation that was selected to predict C&I HLF use per customer, which was consistent with the model selected to predict C&I HLF Total use per customer, Bill Cycle EDD and the HLF Natural Gas Price were statistically significant. The final models, which are provided in Appendix 1, demonstrate excellent goodness of fit and pass all statistical tests applied.

Table IV-28 below summarizes the C&I HLF customer model results for customer growth, use per customer, and C&I HLF demand for the forecast period as compared to the historical reference period.

Table IV-28: C&I HLF Sales Customer Segment Forecast – New Hampshire Division

Split Year	Average Customer Historical	Normal Year Historical (Dth/Customer)	Demand Normal Year Historical (Dth)
2009/10	1,067	390	415,788
2010/11	1,028	392	402,882
2011/12	966	385	372,322
2012/13	893	407	363,594
2013/14	915	400	366,156
CAGR	-3.8%	0.7%	-3.1%
Split Year	Average Customer Forecast	Normal Year Forecast (Dth/Customer)	Demand Normal Year Forecast (Dth)
2014/15	916	382	349,914
2015/16	908	372	338,038
2016/17	901	377	339,356
2017/18	894	385	344,010
2018/19	887	391	346,756
2019/20	878	385	337,924
CAGR	-0.9%	0.2%	-0.7%

Over the forecast period, the number of New Hampshire C&I HLF Sales customers is projected to decline by -0.9% annually compared to the declining rate of-3.8% over the historical reference period. Use per customer for the C&I HLF Sales Customer Segment is expected to remain flat over the forecast period, roughly at levels observed over the historical period. The C&I HLF Sales Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I HLF Sales customers each month by the forecasted C&I HLF Sales use per customer for that month. Over the forecast period, C&I HLF Sales demand is expected to decline annually by -0.7%, which is a slower rate of decline than was observed during the historical reference period. Despite applying common models and forecast data, New Hampshire C&I HLF Sales demand growth is projected to be much lower than New Hampshire C&I HLF Total demand growth. These results appear reasonable given the information available.

j) C&I Sales Customer Segment Demand – New Hampshire Division

C&I Sales customer demand for the New Hampshire Division is summarized in Table IV-29 below as the sum of the C&I LLF Sales customer segment demand and the C&I HLF Sales customer segment demand less expected C&I Sales energy efficiency savings. C&I Sales demand growth is projected to be unchanged over the planning period, which differs from C&I Total demand growth, which is projected to increase 1.6 percent annually.

Table IV-29: C&I Sales Customer Segment Demand (Dth) - New Hampshire Division

Split Year	C&I LLF Sales Demand	C&I HLF Sales Demand	Special Contract Sales Demand	C&I Sales EE Savings	C&I Sales Demand
2014/15	1,532,287	349,914	0	-23,904	1,858,297
2015/16	1,542,710	338,038	0	-47,872	1,832,876
2016/17	1,575,563	339,356	0	-73,756	1,841,162
2017/18	1,613,279	344,010	0	-95,062	1,862,228
2018/19	1,642,936	346,756	0	-114,458	1,875,235
2019/20	1,650,768	337,924	0	-131,328	1,857,364
CAGR	1.5%	-0.7%	n/a	40.6%	0.0%

k) C&I Transportation Customer Segment Demand – New Hampshire Division

C&I Transportation Customer Segment demand is the portion of C&I Total customer segment demand from customers who received transportation service over the historical period. C&I Transportation demand was calculated by subtracting C&I Sales demand from C&I Total demand for each customer segment. C&I Transportation demand for the New Hampshire Division is summarized in Table IV-30 below as the sum of the C&I LLF Transportation customer segment demand and the C&I HLF Transportation customer segment demand less expected C&I Transportation energy efficiency savings. C&I Transportation demand is projected to increase by 2.4 percent annually over the forecast period.

Table IV-30: C&I Transportation Customer Segment Demand (Dth) - New Hampshire Division

Split Year	C&I LLF Transport Demand	C&I HLF Transport Demand	Special Contract Transport Demand	C&I Transport EE Savings	C&I Transport Demand
2014/15	1,288,518	1,823,925	107,661	-20,102	3,200,002
2015/16	1,325,351	1,874,360	104,401	-41,127	3,262,985
2016/17	1,363,310	1,971,161	102,174	-63,820	3,372,825
2017/18	1,396,423	2,072,996	104,412	-82,284	3,491,548
2018/19	1,420,862	2,156,324	107,634	-98,987	3,585,834
2019/20	1,437,029	2,174,645	109,995	-114,324	3,607,345
CAGR	2.2%	3.6%	0.4%	41.6%	2.4%

l) Capacity Assigned v. Capacity Exempt Transportation – New Hampshire Division

In order to separately estimate Capacity Exempt and Capacity Assigned C&I Transportation Demand, the Company produced a regression model for Capacity Exempt Demand expressed as a percentage of Total C&I Transportation Demand. Table IV-31 below summarizes the Capacity Exempt and Capacity Assigned demand for the forecast period. The final model, which is provided in Appendix 1, demonstrates excellent goodness of fit and passes all statistical tests applied.

Table IV-31: Capacity Assigned v. Capacity Exempt Demand (Dth) - New Hampshire Division

Split Year	C&I Transport Capacity Assigned	C&I Transport Capacity Exempt	C&I Transport Demand
2014/15	1,481,493	1,718,509	3,200,002
2015/16	1,509,043	1,753,942	3,262,985
2016/17	1,558,634	1,814,191	3,372,825
2017/18	1,612,347	1,879,201	3,491,548
2018/19	1,655,817	1,930,016	3,585,834
2019/20	1,666,583	1,940,763	3,607,345
CAGR	2.4%	2.5%	2.4%

m) Incremental Energy Efficiency Savings – New Hampshire Division

An out-of-model adjustment was made to reduce the demand forecast for expected incremental savings associated with existing energy efficiency programs. The Company prepared incremental energy savings estimates associated with current Residential and C&I energy efficiency programs for the forecast period for the New Hampshire Division. Since historical energy efficiency savings are already reflected in metered consumption, Northern defined the twelve month period ending March 2014 as the base period and calculated incremental efficiency savings by netting the estimated savings for this base period from future projected savings. Table IV-32 below provides the cumulative energy efficiency savings that are incremental to the base period for each year of the forecast period. These EE Savings were deducted from the Customer Segment demand forecasts as shown in the customer segment demand tables presented above.

Table IV-32: Incremental Energy Efficiency Savings (Dth) - New Hampshire Division

Split Year	Residential EE Savings	C&I EE Savings	Total EE Savings
2014/15	-14,516	-44,006	-58,522
2015/16	-29,319	-88,999	-118,318
2016/17	-44,123	-137,577	-181,700
2017/18	-58,786	-177,345	-236,131
2018/19	-72,543	-213,444	-285,987
2019/20	-83,159	-245,653	-328,812
CAGR	41.8%	41.0%	41.2%

n) Customer Segment Demand Forecast Results – New Hampshire Division

The end result of the New Hampshire Division customer segment modeling is presented below in Table IV-33, where the demand determined by customer segment, assuming normal weather, is tallied for the entire Division.

Table IV-33: Total Customer Segment Demand (Dth) - New Hampshire Division

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	Customer Segment Total Demand
2014/15	1,751,143	1,858,297	3,196,298	6,805,737
2015/16	1,771,327	1,832,876	3,263,058	6,867,261
2016/17	1,801,737	1,841,162	3,376,554	7,019,452
2017/18	1,836,484	1,862,228	3,495,128	7,193,840
2018/19	1,871,730	1,875,235	3,588,301	7,335,265
2019/20	1,900,560	1,857,364	3,608,403	7,366,327
CAGR	1.7%	0.0%	2.5%	1.6%

D. Normal Year Throughput Forecast

The Normal Year Throughput forecast is calculated by summing (1) the demand forecast as developed using the Customer Segment models, which utilized normal billing cycle weather data, (2) Company Use and (3) Losses and Unbilled sales.

1. Company Use

Company Use includes natural gas used to heat Company buildings, to run the Lewiston LNG plant, and to pre-heat gas[111]. In the regression equations that were selected to predict Company Use for the Maine and New Hampshire Divisions, Bill Cycle EDD, monthly dummy variables, and time-specific dummy variables and interactions were statistically significant. Over the forecast period, Company Use for both the Maine and New Hampshire Divisions is projected to remain constant as shown in Table IV-34 below. For convenience, both normal year and design year Company Use are listed below.

111 In some circumstances, gas is "pre heated" to prevent frost heaves above large mains that are located a short distance downstream from a regulator station.

Table IV-34: Northern Company Use - Normal Year, Design Year (Dth)

	Normal Year			Design Year		
Split Year	Maine Division	NH Division	Total Company Use	Maine Division	NH Division	Total Company Use
2014/15	5,265	2,127	7,392	5,437	2,238	7,675
2015/16	5,265	2,127	7,392	5,437	2,238	7,675
2016/17	5,265	2,127	7,392	5,437	2,238	7,675
2017/18	5,265	2,127	7,392	5,437	2,238	7,675
2018/19	5,265	2,127	7,392	5,437	2,238	7,675
2019/20	5,265	2,127	7,392	5,437	2,238	7,675
CAGR	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

2. Losses and Unbilled Sales

The Customer Segment and Company Use forecasts discussed above represent the projected gas use, measured at the customer meter on a billing period basis. To produce forecasts that represent gate station measures on a calendar period basis, the Customer Segment and Company Use forecasts were adjusted for losses and unbilled sales. Four years of historical calendar month total throughput data (measured at the gate station) and billing month gas use (measured at the customer meter) (i.e., "Gas Accounted For") was compiled to develop forecasts of percentage losses and unbilled sales by Division. Table IV-35 below shows the losses and unbilled sales percentage calculations for the Maine Division, and Table IV-36 below shows the losses and unbilled sales percentage calculations for the New Hampshire Division.

Table IV-35: Losses and Unbilled Sales (Dth) – Maine Division

Period	Total System Throughput	Total Retail Billed Sales	Company Use	Unbilled Sales	Total Gas Accounted For	Losses and Unbilled Sales	% Losses and Unbilled Sales
6/10-5/11	8,793,468	8,594,978	6,992	153,631	8,755,601	37,867	
6/11-5/12	8,526,773	8,350,164	5,732	-57,748	8,298,148	228,626	
6/12-5/13	9,552,201	9,331,340	5,910	3,503	9,340,753	211,448	
6/13-5/14	10,495,679	10,213,010	6,918	11,989	10,231,917	263,762	
Period	37,368,121	36,489,492	25,551	111,375	36,626,418	741,703	1.98%

Table IV-36: Losses and Unbilled Sales (Dth) – New Hampshire Division

Period	Total System Throughput	Total Retail Billed Sales	Company Use	Unbilled Sales	Total Gas Accounted For	Losses and Unbilled Sales	% Losses and Unbilled Sales
6/10-5/11	7,140,818	7,072,171	652	108,144	7,180,966	-40,148	
6/11-5/12	6,451,676	6,384,382	1,583	-68,161	6,317,804	133,872	
6/12-5/13	7,283,988	7,171,866	2,100	70,501	7,244,466	39,521	
6/13-5/14	8,100,570	8,101,527	2,242	-51,369	8,052,400	48,170	
Period	28,977,052	28,729,946	6,576	59,115	28,795,637	181,415	0.63%

3. Normal Year Throughput Forecasts

Normal Year Throughput forecasts were calculated as the sum of customer segment demand calculated using normal weather billing cycle data, Company Use, and Losses and Unbilled Sales. Table IV-37 and Table IV-38 below present the Normal Year Throughput forecasts for the Maine Division and New Hampshire Division, respectively. Results in Maine reflect strong projected growth in all customer segments. Normal Year Throughput for the Maine Division is projected to grow by about 4 percent annually over the forecast period. Results for New Hampshire reflect growth in residential and C&I Transportation demand while C&I Sales demand is projected to be flat. Normal Year Throughput is projected to grow by 1.6 percent annually over the forecast period.

Table IV-37: Normal Year Throughput (Dth) – Maine Division

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	Company Use	Losses and Unbilled	Normal Year Throughput
2014/15	1,502,014	2,583,723	7,373,291	5,265	226,889	11,691,183
2015/16	1,580,416	2,700,552	7,428,541	5,265	231,848	11,946,623
2016/17	1,686,769	2,794,378	7,869,100	5,265	244,535	12,600,047
2017/18	1,805,170	2,872,379	8,394,068	5,265	258,818	13,335,699
2018/19	1,923,796	2,938,536	8,822,232	5,265	270,954	13,960,784
2019/20	2,020,478	2,989,477	8,834,874	5,265	274,128	14,124,222
CAGR	6.1%	3.0%	3.7%	0.0%	3.9%	3.9%

Table IV-38: Normal Year Throughput (Dth) – New Hampshire Division

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	Company Use	Losses and Unbilled	Normal Year Throughput
2014/15	1,751,143	1,858,297	3,200,002	2,127	42,899	6,854,468
2015/16	1,771,327	1,832,876	3,262,985	2,127	43,263	6,912,578
2016/17	1,801,737	1,841,162	3,372,825	2,127	44,199	7,062,050
2017/18	1,836,484	1,862,228	3,491,548	2,127	45,299	7,237,686
2018/19	1,871,730	1,875,235	3,585,834	2,127	46,197	7,381,122
2019/20	1,900,560	1,857,364	3,607,345	2,127	46,401	7,413,797
CAGR	1.7%	0.0%	2.4%	0.0%	1.6%	1.6%

E. Design Year Throughput Forecast

In addition to developing a Normal Year Throughput forecast, Northern developed forecasts of Throughput under extreme weather conditions, referred to as “Design Year” and “Design Day” forecasts.

While the Normal Year Throughput forecast is based on normal weather conditions, the Company maintains supply planning standards of 1-in-33 year probably of occurrence for both design year and design day. The Design Year Throughput forecast was developed to determine the amount of gas expected to be consumed on the system during an extremely cold year. To determine forecast firm throughput associated with design weather conditions, the Customer Segment firm demand and Company Use forecasts were re-calculated using weather data that reflects design conditions.

The Company’s normal and design planning standard effective degree-day (EDD) data are based on analyses of historical EDD data for the Maine Division (measured at the Portland, Maine weather station located at the Portland International Jetport) and for the New Hampshire Division (measured at the Portsmouth, New Hampshire weather station, located at Pease International Tradeport).

The Normal Year EDD was determined to be 7,532 EDD for Maine and 6,991 EDD for New Hampshire. Normal Year EDD were calculated by summing the 30 year average billing cycle EDD for each month using data from November 1, 1983 to October 31, 2013 (i.e., the most recent 30 gas years of data available at the time of the analysis). The 30 year monthly averages, seasonal and total annual EDD for both Divisions are shown in Table IV-39 below.

Table IV-39: Normal Year and Design Year Billing Cycle Monthly EDD

	Maine Division		New Hampshire Division	
Month	Normal Year	Design Year	Normal Year	Design Year
Nov	667	744	614	690
Dec	1,007	1,123	950	1,068
Jan	1,303	1,453	1,240	1,395
Feb	1,327	1,480	1,255	1,411
Mar	1,126	1,255	1,073	1,207
Apr	858	858	798	798
May	530	530	467	467
Jun	236	236	193	193
Jul	50	50	36	36
Aug	14	14	9	9
Sep	80	80	63	63
Oct	334	334	292	292
Winter	5,430	6,055	5,133	5,771
Summer	2,102	2,102	1,858	1,858
Total	7,532	8,157	6,991	7,629

The Design Year EDD represents extreme winter conditions with a statistically defined probability of occurring on a very infrequent basis (once in 33 years). The Design Year EDD was used to develop a forecast of Design Year Throughput to estimate the level of consumption during an extremely cold year. The Design Year planning standard was determined to be 8,157 EDD for Maine and 7,629 EDD for New Hampshire. The Company's Design Year standard is determined to result in a 1-in-33 year frequency of occurrence for the peak winter period (November through March), together with normal weather for the summer months (April through October). Design winter EDD were calculated by first summing the billing cycle EDD for each winter from 1983/84 through 2012/13 (i.e., the most recent 30 gas years of data available). The 30 year average and standard deviation of the winter EDD was then calculated and used to calculate the winter EDD associated with a 1-in-33 year probability of occurrence. Monthly Design Year EDD for each of the five winter months were determined by adding the standard deviation for each winter month times an adjustment factor equal to the normal EDD for each winter month.[112] The Design Year monthly and total annual EDD for both Divisions are shown above in Table IV-39.

To determine the throughput associated with Design Year weather in each Division, the Customer Segment and Company Use models with EDD coefficients (i.e., Residential Heating use per

[112] The adjustment factor was calculated as follows: Adjustment factor = (Design Winter EDD – Normal Winter EDD) / (∑ monthly standard deviations of winter months).

customer, Residential Non-Heating use per customer, C&I LLF Total use per customer, C&I HLF Total use per customer, C&I LLF Sales use per customer, C&I HLF Sales use per customer, Special Contracts, and Company Use) were re-run using Design EDD in the forecast period. The Design Year Customer Segment forecast results by Division were reduced by projected energy efficiency savings to establish Design Year customer segment demand, which was further reduced by design Company Use and adjusted for losses and unbilled sales to produce Design Year Throughput, similar to the process used to develop the Normal Year customer segment demand and Throughput. Table IV-40 and Table IV-41 below summarize the Design Year Throughput forecasts for the Maine Division and New Hampshire Division, respectively.

Table IV-40: Design Year Throughput (Dth) – Maine Division

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	Company Use	Losses and Unbilled	Design Year Throughput
2014/15	1,586,055	2,738,916	7,641,865	5,437	236,943	12,209,217
2015/16	1,667,816	2,863,688	7,706,347	5,437	242,309	12,485,598
2016/17	1,777,620	2,963,628	8,154,100	5,437	255,328	13,156,112
2017/18	1,899,594	3,046,547	8,684,961	5,437	269,896	13,906,435
2018/19	2,021,885	3,116,848	9,118,065	5,437	282,285	14,544,520
2019/20	2,122,232	3,171,253	9,134,801	5,437	285,680	14,719,402
CAGR	6.0%	3.0%	3.6%	0.0%	3.8%	3.8%

Table IV-41: Design Year Throughput (Dth) – New Hampshire Division

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	Company Use	Losses and Unbilled	Design Year Throughput
2014/15	1,841,617	1,978,400	3,285,219	2,238	44,763	7,152,237
2015/16	1,861,248	1,950,969	3,348,436	2,238	45,112	7,208,003
2016/17	1,892,966	1,959,671	3,459,952	2,238	46,069	7,360,896
2017/18	1,929,080	1,981,113	3,580,050	2,238	47,189	7,539,670
2018/19	1,965,763	1,994,073	3,675,275	2,238	48,101	7,685,450
2019/20	1,996,162	1,975,863	3,697,282	2,238	48,317	7,719,861
CAGR	1.6%	0.0%	2.4%	0.0%	1.5%	1.5%

F. Design Day Throughput

The Design Day planning standard represents extreme weather conditions on a single day that have a statistically defined probability of occurring on a very infrequent basis. The Design Day standard was used to develop a forecast of Design Day Throughput, which is the amount of gas expected to be consumed on Northern's system during the coldest day of the year. The Design Day effective degree-days using Northern's 1-in-33 year planning standard was determined to be 78.1 EDD for the Maine Division and 78.5 EDD for the New Hampshire Division. The Design Day EDD was calculated by first identifying the peak day EDD (i.e., the coldest day) for each winter from 1983/84 through 2012/13 (i.e., the most recent thirty gas years of data available, consistent with Design Year). The 30 year average and standard deviation of the peak days was calculated and used to calculate the Design Day EDD associated with a 1-in-33 year probability of occurrence. The Design Day EDD for both Divisions is shown in Table IV-42 below, along with the EDD associated with Northern's historical peak day.

Table IV-42: Design Day EDD

	Maine Division	New Hampshire Division
Design Day EDD	78.1	78.5
Historical Peak Day, January 2, 2014	79.8	75.1

To estimate the throughput associated with Design Day weather in each Division, a daily Design Day model was developed for each Division. The dependent variable in these models was historical daily throughput for the period November 1, 2012 through March 31, 2014 by Division and the independent variables included actual daily EDD and various dummy variables. For the Design Day regression models, independent variables were included for (1) days of the week; (2) winter months; EDD calculated to reflect very cold temperatures (i.e., EDD base 15)[113]; and the prior day's EDD. The regression models are presented in Appendix 1.

For each Division, the regression equation was adjusted by replacing the EDD-based variables with Design Day EDD. The resulting throughput was established as the 2014/15 Design Day Throughput, and was adjusted based on the growth in Design Year Throughput for each Division to extend the Design Day Throughput forecast throughout the planning period. Table IV-43 presents the Design Day Throughput forecast for the Maine Division and the New Hampshire Division and the Company totals for the forecast period.

On January 7, 2015, Northern experienced cold weather conditions with 65 EDD recorded in the Maine Division and 68 EDD recorded in the New Hampshire Division. Northern applied these actual EDD values to its design day models and calculated estimated daily throughput of 65,708 Dth for Maine and 57,742 Dth for New Hampshire, for a total daily forecast of 123,450 Dth. Actual throughput on January 7, 2015, was 67,708 Dth in the Maine Division and 58,106 Dth in the New Hampshire Division, for a daily total of 125,814 Dth. The New Hampshire model under predicted by 364 Dth, or 0.6%, while the Maine

[113] EDD typically have a base of 65, therefore days with average temperatures greater than or equal to 65 degrees have 0 EDD, and days that are colder than 65 degrees have EDD = 65 – average temperature (adjusted for wind). Changing the base in the EDD calculation to something much less than 65 (e.g., 15) isolates very cold days since days with average temperatures greater than or equal to 15 degrees have 0 EDD and days that are colder than 15 degrees have EDD = 15 – average temperature (adjusted for wind).

model under predicted by 2,000 Dth, or 3.0%. Collectively, the models were off by 1.9%. These results suggest Northern's design day throughput models are reasonably accurate.

Table IV-43: Design Day Throughput (Dth)

Split Year	Maine Division	NH Division	Design Day Throughput
2014/15	83,737	63,919	147,656
2015/16	85,633	64,417	150,050
2016/17	90,232	65,783	156,015
2017/18	95,378	67,381	162,759
2018/19	99,754	68,684	168,438
2019/20	100,954	68,991	169,945
CAGR	3.8%	1.5%	2.9%

For comparison purposes, Northern's historical peak day throughput was 135,799 Dth, which occurred on January 2, 2014, at EDD conditions comparable to the Design Day EDD standard. The level of the historical peak day may seem low relative to model expectations; however the result occurred on the day after a holiday during so it is unclear whether most C&I customers, which as documented in the customer segment modeling, represent the largest consuming sector, were fully operational during the peak day. Additionally, Northern has no data regarding the degree to which dual fuel customers may have been consuming an alternative fuel.

V. Planning Load Forecast

A. Introduction

Section V presents Northern's planning load forecast. Determining planning load is the primary objective of the demand forecasting process and the planning load forecast is the primary input to the resource planning process.

This IRP uses the definitions listed in Table V-1 to distinguish among customer loads in terms of their capacity assignment status and contributions to planning load.

Table V-1: Capacity Assignment and Planning Load Terminology

Term	Definition
Capacity Exempt Load	Load of certain Transportation customers who are not subject to Capacity Assignment under the Delivery Service Terms and Conditions
Capacity Assigned Load	Portion of load of Transportation customers who are subject to Capacity Assignment that is subject to Capacity Assignment under the Delivery Service Terms and Conditions (50 percent in Maine, 100 percent in New Hampshire)
Non-Capacity Assigned Load	Portion of load of Transportation customers who are subject to Capacity Assignment that is not subject to Capacity Assignment under the Delivery Service Terms and Conditions (50 percent in Maine, not applicable in New Hampshire)
Long-Term Planning Load	Total Residential Sales Demand plus 50 percent of all C&I Sales Demand and Capacity Assigned Transportation Demand in Maine and 100 percent of all C&I Sales Demand and Capacity Assigned Transportation Demand in New Hampshire, adjusted for measurement at the gate station on a calendar period basis
Short-Term Planning Load	Sales Demand plus Capacity Assigned Load, adjusted for measurement at the gate station on a calendar period basis
Alternative Planning Load	Total System Demand less Dual Fuel Capability, adjusted for measurement at the gate station on a calendar period basis

The Integrated Resource Plan addresses planning for the supply requirements of customers who rely on the Company for reliable and reasonably priced supply or for resources they can use to access such supply directly (through a retail supplier). Such resources typically include upstream pipeline transportation service, underground storage service and on-system LNG production, all of which require significant long-term commitments. Supplies delivered by others can also be purchased at inlets to the Company's system, although as detailed in Section III, Regional Market Overview, such supplies are subject to erratic pricing and questionable availability. The Company does not plan for a significant and growing number of customers, who have availed themselves of provisions of the Company's Delivery Service Tariffs that allow for capacity exempt status.[114]

The planning load forecasts reflect the gas usage of those customers to whom Northern expects to provide supply or assign capacity. Planning load forecasts were created for normal year, design year and design day conditions. Since the capacity assignment provisions of the Delivery Service Tariffs in the Maine Division and New Hampshire Division are different, planning load was calculated by state. In addition, because of uncertainty as to whether new C&I customers will choose to become capacity exempt and because the Company's Delivery Service Tariff in the Maine Division provides for reductions to planning load when sales customers choose transportation service, two versions of planning load were determined. One version, referred to as "Long-Term Planning Load," represents only the throughput requirements of those customer loads that will necessarily be subject to Northern's planning activities. The other version, referred to as "Short-Term Planning Load," represents requirements of customer loads that would be subject to Northern's planning activities if current trends among sales and transportation customers and among capacity exempt and capacity assigned transportation customers persist.

Long-Term Planning Load is the measure Northern uses to assess the adequacy of its long-term resource portfolio. Northern also recognizes the need to provide supply from time to time for those additional customer loads that are not permanent planning load obligations. Such loads, which are represented as the difference between Short-Term Planning Load and Long-Term Planning Load, would typically be served with delivered supplies.

Lastly, for illustrative purposes only, Northern is also providing planning load calculations based on its proposal in Maine Public Utilities Commission Docket No. 2014-132, as modified in the January 16, 2015 testimony. Under the proposal, the current standard for exemption from capacity assignment, which is that a C&I customer never received sales service for a sustained period from the Company, would be replaced by a new standard which would exempt customer loads that are backed by dual fuel capability. Thus, as proposed, all customers without dual fuel capability would be assigned capacity. Northern refers to this proposed version as "Alternative Planning Load."

The remainder of this Planning Load Forecast section is organized as follows:

Part B, <u>Overview of Capacity Assignment</u>, summarizes the capacity assignment rules in Northern's Delivery Service Tariffs and their impact on planning in order to provide context for the distinctions drawn in the planning load calculations;

Part C, <u>Long-Term Planning Load</u>, presents the calculations and results of planning load requirements for known customer loads;

[114] The Company has concerns that as more and more customers become exempt from capacity assignment, and therefore fall outside of the Company's planning process, that over reliance on supplies purchased at inlets to the Company's system will increase prices and compromise reliability for all customers. These concerns have been raised before the Maine Public Utilities Commission in Docket No. 2014-132.

Part D, Short-Term Planning Load, presents the calculations and results of planning load requirements for customer loads that may rely on sales service or be subject to capacity assignment;

Part E, Alternative Planning Load, presents illustrative calculations and results of planning load requirements for all customers less estimated loads backed by dual fuel capability;

Part F, Comparison of Planning Load Cases, provides comparisons of Short-Term Planning Load and Alternative Planning Load to Long-Term Planning Load.

B. Overview of Capacity Assignment

The Company operates an unbundled distribution system pursuant to the Delivery Service Terms and Conditions approved by the Maine Public Utilities Commission ("ME Delivery Service Tariff") and the New Hampshire Public Utilities Commission ("NH Delivery Service Tariff", or jointly "Delivery Service Tariffs"). The Delivery Service Tariffs allow commercial and industrial ("C&I") customers to purchase their gas supply from retail suppliers and establish the rules under which retail suppliers deliver supply to Northern's system and under which Northern provides services such as administration, metering and balancing. The Delivery Service tariffs also include Capacity Assignment provisions that directly and significantly impact the amount of, and the certainty associated with, Northern's planning load.

1. Capacity Assignment Rules

The basic Capacity Assignment provisions of the Delivery Service Tariff for Northern's Maine Division are as follows:

1. Any Customer at a new service location who commences Transportation Service within 60 days of initiating service for high-use customers or within 120 days of initiating service for low-use customers is not assigned capacity.
2. All other Customers, including Sales Service customers, initiating Transportation Service are assigned capacity equal to 50 percent of the Customer's estimated Peak Day Requirement. Once the Customer's share of capacity is established, it remains unchanged so long as the Customer remains on Transportation Service.
3. No assignable capacity is directly released to Retail Suppliers. All assignable capacity is provided as Company-Managed service.
4. The resources subject to capacity assignment are limited to Northern's Washington 10 storage and its Delivered peaking supply contracts. Retail Suppliers may nominate to purchase Company-Managed commodity through these resources for the months of November through March, subject to maximum daily contract quantities ("MDCQ") and annual contract quantities ("ACQ").

5. Retail Suppliers under the Maine Delivery Service Tariff pay a demand rate equal to the average annual cost of all of Northern's capacity, which is charged over the five-month winter period. Commodity rates similarly reflect the cost of unassigned resources.

The basic Capacity Assignment provisions of the Delivery Service Tariff for Northern's New Hampshire Division are as follows:

1. Any Customer receiving Sales Service on or after March 1, 2000, who later initiates Transportation Service, is assigned capacity equal to 100 percent of the Customer's estimated Peak Day Requirement. Once the Customer's share of capacity is established, it remains unchanged so long as the Customer continues to receive Transportation Service.
2. Any Customer receiving Transportation Service on or before March 1, 2000 is not assigned capacity.[115]
3. Any Customer at a new service location who commences Transportation Service within 120 days of initiating service is not assigned capacity.
4. With minor exceptions, Retail Suppliers in the New Hampshire Division are assigned resources from Northern's entire capacity portfolio. A portion of the assignable capacity is released directly to the Retail Suppliers through each pipeline's Electronic Bulletin Board. A portion of the assignable capacity is provided as a "Company-Managed" Service. Company-Managed capacity is controlled by the Company, rather than being released to the Retail Suppliers, and the Company arranges for delivery on behalf of the Retail Suppliers when they nominate supply.
5. Retail Suppliers pay the actual cost of the resources provided under the New Hampshire Delivery Service Tariff.

2. Impact on Planning

The Delivery Service Tariffs allow all new C&I customers to avoid Capacity Assignment. Thus, even though Northern is adding significant numbers of new C&I customers as established in Section IV, potentially none of the added load associated with these new customers will become either Sales Service or Capacity Assigned Transportation Service and therefore add to Northern's Planning Load. At the time of this filing, an estimated 34 percent of design year throughput and 28 percent of design day throughput on the Company's system is Capacity Exempt, and thus excluded from Planning Load.[116] The Company anticipates that the vast majority of new C&I customers will elect to become Capacity Exempt with the long-term result that Northern's planning load will reflect a modest and shrinking portion of the

[115] These customers had the option to elect capacity assignment, subject to availability, as determined by Northern.
[116] Please see 2014/15 capacity exempt and non-capacity assigned values in Tables V-8 and V-9 for design year and Tables V-11 and V-12 for design day. Please see Table V-16 for design year Throughput and Table V-17 for design day Throughput.

Company's throughput. Since Northern is located in a largely illiquid region, as discussed in Section III, the current capacity assignment rules introduce pricing and reliability risks.

The ME Delivery Service Tariff provides that existing C&I Sales customers who choose a retail supplier will only be assigned capacity to match 50 percent of the customer's peak day requirement. This provision creates significant uncertainty in planning load. For example, in the Maine Division, the load of a new C&I customer can create a planning load obligation equal to zero if the customer never takes Sales Service, equal to 50 percent of the customer's peak day requirements if the customer takes Sales Service long enough to trigger Capacity Assignment requirements and later chooses a retail supplier, or 100 percent if the customer goes to and stays on Sales Service.

The calculations that follow apply the capacity assignment provisions to the demand forecast results to in order to determine the Company's planning load requirements.

C. Long-Term Planning Load

1. Introduction

As described earlier, Long-Term Planning Load is the throughput associated with customer loads that, based on the capacity assignment rules, will either receive Company supply or be subject to capacity assignment. This is the load that financially supports the long-term portfolio and for which the Company conducts its long-term planning and contracting activities.

Long-Term Planning Load is based on two primary assumptions. First, that all new C&I customers will choose to be supplied by retail marketers making them capacity exempt and second, that all Maine Division C&I Sales customers will choose Transportation service. Although extensive effort was put forth developing statistical models to project trends in C&I Sales relative to C&I Transportation and Capacity Assigned transportation relative to Capacity Exempt transportation, ultimately there is no reliable means of projecting how customers will choose to be supplied in the future. This applies to whether new C&I customers in both states will choose to become capacity exempt and to whether current C&I Sales customers in Maine will continue to purchase their gas supply from Northern. Unfortunately, these uncertain customer outcomes impact Northern's Planning Load under the current Delivery Service Terms and Conditions. For this reason, Northern does not rely upon the forecasted splits of demand requirements by capacity assignment status in determining Long-Term Planning Load.

Given these assumptions, the Long-Term Planning Load grows only as Residential sales grow. Over time, Long-Term Planning Load would also grow if and when capacity exempt customers choose to receive Sales Service from the Company.[117]

[117] New Hampshire Long-Term Planning Load would grow by 100 percent of new C&I sales customer peak day requirements; Maine Long-Term Planning Load would grow by 50 percent of new C&I sales customer peak day requirements.

All calculations are based on evaluated customer loads rather than actual customer Total Contract Quantities (TCQ). Further, annual Maine throughput volumes are not reduced for the summer period when Capacity Assignment goes to zero under the current rules.

2. Design Year Long-Term Planning Load

The calculation of Design Year Long-Term Planning Load is presented below. The calculation of Design Day Long-Term Planning Load follows.

Separate calculations of planning load were performed for each division, primarily to accommodate the difference in rules whereby capacity assigned customers in Maine are assigned 50 percent of their peak day requirement and the other 50 percent is not subject to assignment, while capacity assigned customers in New Hampshire are assigned 100 percent of their peak day requirement.

In converting the various throughput forecasts (normal year, design year, design day) into planning load forecasts, it was first necessary to allocate system throughput among customer segments. Specifically, system throughput was allocated to Residential, C&I Sales and C&I Transportation customer segments on the basis of relative demand over the forecast horizon for each division as described in Appendix 2, Supplemental Materials for the Planning Load Forecast. The customer segment throughput values were then used as inputs into the Long-Term Planning Load and Short-Term Planning Load calculations.

In order to calculate Long-Term Planning Load, Total C&I Throughput was separated into the three categories listed at the top of Table V-1. These are Capacity Exempt, Capacity Assigned and Non-Capacity Assigned. The current level of Capacity Exempt was set for 2014/15 and then Capacity Exempt was increased over the planning period by the growth in Total C&I, reflecting the assumption that all new C&I customers would be capacity exempt. Capacity Assigned in Maine was calculated as 50 percent of Total C&I less Capacity Exempt, with the other 50 percent being Non-Capacity Assigned. Capacity Assigned in New Hampshire was calculated as 100 percent of Total C&I less Capacity Exempt. Long-Term Planning Load was calculated as Residential Throughput plus Capacity Assigned Throughput. Table V-2 provides the Design Year results for the Maine Division and Table V-3 provides the Design Year results for the New Hampshire Division.

Table V-2: Design Year Long-Term Planning Load (Dth) - Maine Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Res + Cap Ass
Split Year	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Long-Term Planning Load
2014/15	1,618,180	2,794,391	7,796,646	10,591,037	1,667,098	4,461,970	4,461,970	6,080,150
2015/16	1,701,580	2,921,662	7,862,357	10,784,018	1,860,079	4,461,970	4,461,970	6,163,550
2016/17	1,813,566	3,023,557	8,318,989	11,342,546	2,418,607	4,461,970	4,461,970	6,275,536
2017/18	1,937,964	3,108,084	8,860,387	11,968,471	3,044,532	4,461,970	4,461,970	6,399,934
2018/19	2,062,689	3,179,751	9,302,080	12,481,831	3,557,891	4,461,970	4,461,970	6,524,659
2019/20	2,165,052	3,235,239	9,319,112	12,554,350	3,630,411	4,461,970	4,461,970	6,627,022
CAGR	6.0%	3.0%	3.6%	3.5%	16.8%	0.0%	0.0%	1.7%

Cap Exempt = 2014/15 Cap Exempt + Total C&I growth (Total C&I less 2014/15 Total C&I)
Cap Assigned = 50% * (Total C&I less Cap Exempt); Non-Cap Assigned = 50% * (Total C&I less Cap Exempt)
Long-Term Planning Load = Residential + Cap Assigned

Table V-3: Design Year Long-Term Planning Load (Dth) - New Hampshire Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Res + Cap Ass
Split Year	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Long-Term Planning Load
2014/15	1,853,800	1,991,487	3,306,951	5,298,438	1,755,476	3,542,962	0	5,396,762
2015/16	1,873,555	1,963,870	3,370,578	5,334,448	1,791,486	3,542,962	0	5,416,517
2016/17	1,905,471	1,972,616	3,482,808	5,455,425	1,912,463	3,542,962	0	5,448,433
2017/18	1,941,809	1,994,186	3,603,674	5,597,860	2,054,898	3,542,962	0	5,484,771
2018/19	1,978,724	2,007,220	3,699,506	5,706,727	2,163,765	3,542,962	0	5,521,686
2019/20	2,009,320	1,988,887	3,721,654	5,710,541	2,167,579	3,542,962	0	5,552,282
CAGR	1.6%	0.0%	2.4%	1.5%	4.3%	0.0%	n/a	0.6%

Cap Exempt = 2014/15 Cap Exempt + Total C&I growth (Total C&I less 2014/15 Total C&I)
Cap Assigned = 100% * (Total C&I less Cap Exempt)
Long-Term Planning Load = Residential + Cap Assigned

The results for each division were tallied to establish Northern's Design Year Long-Term Planning Load, which is shown in Table V-4. Although Total C&I Throughput in the Maine Division is double that of the New Hampshire Division, Design Year Long-Term Planning Load in Maine is projected to be only about 20 percent higher than in New Hampshire by the end of the planning period.

Table V-4: Design Year Long-Term Planning Load (Dth)

	Maine Div.	NH Div.	Northern
Split Year	Long-Term Planning Load	Long-Term Planning Load	Long-Term Planning Load
2014/15	6,080,150	5,396,762	11,476,911
2015/16	6,163,550	5,416,517	11,580,067
2016/17	6,275,536	5,448,433	11,723,968
2017/18	6,399,934	5,484,771	11,884,705
2018/19	6,524,659	5,521,686	12,046,344
2019/20	6,627,022	5,552,282	12,179,304
CAGR	1.7%	0.6%	1.2%

3. Design Day Long-Term Planning Load

The calculation of Design Day Long-Term Planning Load was performed in the same manner as described above for Design Year. Table V-5 provides the Design Day results for the Maine Division and Table V-6 provides the Design Day results for the New Hampshire Division.

Table V-5: Design Day Long-Term Planning Load (Dth) - Maine Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Res + Cap Ass
Split Day	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Long-Term Planning Load
2014/15	11,098	19,165	53,474	72,639	8,022	32,309	32,309	43,407
2015/16	11,670	20,038	53,924	73,963	9,346	32,309	32,309	43,979
2016/17	12,438	20,737	57,056	77,793	13,176	32,309	32,309	44,747
2017/18	13,292	21,317	60,769	82,086	17,469	32,309	32,309	45,600
2018/19	14,147	21,808	63,799	85,607	20,990	32,309	32,309	46,456
2019/20	14,849	22,189	63,916	86,105	21,487	32,309	32,309	47,158
CAGR	6.0%	3.0%	3.6%	3.5%	21.8%	0.0%	0.0%	1.7%

Cap Exempt = 2014/15 Cap Exempt + Total C&I growth (Total C&I less 2014/15 Total C&I)
Cap Assigned = 50% * (Total C&I less Cap Exempt); Non-Cap Assigned = 50% * (Total C&I less Cap Exempt)
Long-Term Planning Load = Residential + Cap Assigned

Table V-6: Design Day Long-Term Planning Load (Dth) - New Hampshire Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Res + Cap Ass
Split Day	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Long-Term Planning Load
2014/15	16,567	17,798	29,554	47,351	10,753	36,598	0	53,166
2015/16	16,744	17,551	30,122	47,673	11,075	36,598	0	53,342
2016/17	17,029	17,629	31,125	48,754	12,156	36,598	0	53,627
2017/18	17,354	17,822	32,206	50,027	13,429	36,598	0	53,952
2018/19	17,684	17,938	33,062	51,000	14,402	36,598	0	54,282
2019/20	17,957	17,774	33,260	51,034	14,436	36,598	0	54,555
CAGR	1.6%	0.0%	2.4%	1.5%	6.1%	0.0%	n/a	0.5%

Cap Exempt = 2014/15 Cap Exempt + Total C&I growth (Total C&I less 2014/15 Total C&I)
Cap Assigned = 100% * (Total C&I less Cap Exempt)
Long-Term Planning Load = Residential + Cap Assigned

The results for each division were tallied to establish Northern's Design Day Long-Term Planning Load, which is provided in Table V-7. Whereas Design Year Long-Term Planning Load was greater in the Maine Division, Design Day Long-Term Planning Load is greater in the New Hampshire Division. This result is primarily driven by the higher C&I load factor in the Maine Division.

Table V-7: Design Day Long-Term Planning Load (Dth)

	Maine Div.	NH Div.	Northern
Split Day	Long-Term Planning Load	Long-Term Planning Load	Long-Term Planning Load
2014/15	43,407	53,166	96,572
2015/16	43,979	53,342	97,321
2016/17	44,747	53,627	98,374
2017/18	45,600	53,952	99,552
2018/19	46,456	54,282	100,738
2019/20	47,158	54,555	101,713
CAGR	1.7%	0.5%	1.0%

D. Short-Term Planning Load

1. Introduction

As described earlier, Short-Term Planning Load is throughput associated with customer loads that are not necessarily subject to capacity assignment, but who might rely on Sales service or be subject to capacity assignment over the planning horizon. This load is greater than Long-Term Planning Load and is depicted by the volumes the Company would need to serve in a given year if its forecasts of C&I Sales and Transportation demands come to pass and the current percentage of Capacity Exempt load relative to Capacity Assigned load persists. Short-Term Planning Load assumes that customers will behave during the planning period similarly to the way they behaved in the prior five year period, which is embedded in the Company's forecasts.

The customer loads included in Short-Term Planning Load that are not included in Long-Term Planning Load include 50 percent of Maine C&I Sales customers, who may elect Transportation service and thereby shed 50 percent of their Peak Day demand for Capacity Assignment purposes, and projected new C&I customers who would presumably choose Sales service. Given these assumptions, the Short-Term Planning Load grows as Residential sales grow and as C&I Sales grow.

While the Company would provide resources to meet Short-Term Planning Load at a given point in time, Short-Term Planning Load is a measure of planning load that the Company would not plan to meet with Long-Term resources.

2. Design Year Short-Term Planning Load

The calculation of Design Year Short-Term Planning Load is presented below. The calculation of Design Day Short-Term Planning Load follows.

Short-Term Planning Load was calculated separately by division and the customer segment throughput values were used as inputs into the calculations. In order to calculate Short-Term Planning Load, Total C&I Throughput was separated into the three capacity assignment categories of Capacity Exempt, Capacity Assigned and Non-Capacity Assigned. The current level of Capacity Exempt was set for 2014/15 and then Capacity Exempt was increased over the planning period in proportion to C&I Transportation growth, reflecting the assumption that the current percentage of Capacity Exempt load relative to Capacity Assigned load persists. Capacity Assigned in Maine was calculated as 50 percent of C&I Transportation less Capacity Exempt, with the other 50 percent being Non-Capacity Assigned. Capacity Assigned in New Hampshire was calculated as 100 percent of C&I Transportation less Capacity Exempt. Short-Term Planning Load was calculated as Residential Throughput plus C&I Sales Throughput plus Capacity Assigned Throughput. Table V-8 provides the Design Year results for the Maine Division and Table V-9 provides the Design Year results for the New Hampshire Division.

Table V-8: Design Year Short-Term Planning Load (Dth) - Maine Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Sales + CA
Split Year	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Short-Term Planning Load
2014/15	1,618,180	2,794,391	7,796,646	10,591,037	1,667,098	3,064,774	3,064,774	7,477,345
2015/16	1,701,580	2,921,662	7,862,357	10,784,018	1,681,148	3,090,604	3,090,604	7,713,846
2016/17	1,813,566	3,023,557	8,318,989	11,342,546	1,778,787	3,270,101	3,270,101	8,107,224
2017/18	1,937,964	3,108,084	8,860,387	11,968,471	1,894,550	3,482,919	3,482,919	8,528,967
2018/19	2,062,689	3,179,751	9,302,080	12,481,831	1,988,994	3,656,543	3,656,543	8,898,983
2019/20	2,165,052	3,235,239	9,319,112	12,554,350	1,992,635	3,663,238	3,663,238	9,063,529
CAGR	6.0%	3.0%	3.6%	3.5%	3.6%	3.6%	3.6%	3.9%

Cap Exempt = 2014/15 ratio of Cap Exempt to C&I Transport times C&I Transport forecast
Cap Assigned = 50% * (C&I Transport less Cap Exempt); Non-Cap Assigned = 50% * (C&I Transport less Cap Exempt)
Short-Term Planning Load = Residential + C&I Sales + Cap Assigned

Table V-9: Design Year Short-Term Planning Load (Dth) - New Hampshire Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Sales + CA
Split Year	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Short-Term Planning Load
2014/15	1,853,800	1,991,487	3,306,951	5,298,438	1,755,476	1,551,475	0	5,396,762
2015/16	1,873,555	1,963,870	3,370,578	5,334,448	1,789,252	1,581,326	0	5,418,751
2016/17	1,905,471	1,972,616	3,482,808	5,455,425	1,848,829	1,633,980	0	5,512,067
2017/18	1,941,809	1,994,186	3,603,674	5,597,860	1,912,989	1,690,685	0	5,626,680
2018/19	1,978,724	2,007,220	3,699,506	5,706,727	1,963,862	1,735,645	0	5,721,589
2019/20	2,009,320	1,988,887	3,721,654	5,710,541	1,975,618	1,746,035	0	5,744,243
CAGR	1.6%	0.0%	2.4%	1.5%	2.4%	2.4%	n/a	1.3%

Cap Exempt = 2014/15 ratio of Cap Exempt to C&I Transport times C&I Transport forecast
Cap Assigned = 100% * (C&I Transport less Cap Exempt); Non-Cap Assigned = 0
Short-Term Planning Load = Residential + C&I Sales + Cap Assigned

The results for each division were tallied to establish Northern's Design Year Short-Term Planning Load, which is shown in Table V-10. Although Design Year Long-Term Planning Load in Maine is projected to be only about 20 percent higher than in New Hampshire by the end of the planning period, Design Year Short-Term Planning Load in Maine would be over 50 percent higher than in New Hampshire by the end of the planning period.

Table V-10: Design Year Short-Term Planning Load (Dth)

	Maine Div.	NH Div.	Northern
Split Year	Short-Term Planning Load	Short-Term Planning Load	Short-Term Planning Load
2014/15	7,477,345	5,396,762	12,874,107
2015/16	7,713,846	5,418,751	13,132,597
2016/17	8,107,224	5,512,067	13,619,291
2017/18	8,528,967	5,626,680	14,155,647
2018/19	8,898,983	5,721,589	14,620,572
2019/20	9,063,529	5,744,243	14,807,772
CAGR	3.9%	1.3%	2.8%

3. Design Day Short-Term Planning Load

The calculation of Design Day Short-Term Planning Load was performed in the same manner as described above for Design Year. Table V-11 provides the Design Day results for the Maine Division and Table V-12 provides the Design Day results for the New Hampshire Division.

Table V-11: Design Day Short-Term Planning Load (Dth) - Maine Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Sales + CA
Split Day	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Short-Term Planning Load
2014/15	11,098	19,165	53,474	72,639	8,022	22,726	22,726	52,990
2015/16	11,670	20,038	53,924	73,963	8,090	22,917	22,917	54,626
2016/17	12,438	20,737	57,056	77,793	8,559	24,248	24,248	57,424
2017/18	13,292	21,317	60,769	82,086	9,116	25,826	25,826	60,435
2018/19	14,147	21,808	63,799	85,607	9,571	27,114	27,114	63,069
2019/20	14,849	22,189	63,916	86,105	9,588	27,164	27,164	64,202
CAGR	6.0%	3.0%	3.6%	3.5%	3.6%	3.6%	3.6%	3.9%

Cap Exempt = 2014/15 ratio of Cap Exempt to C&I Transport times C&I Transport forecast
Cap Assigned = 50% * (C&I Transport less Cap Exempt); Non-Cap Assigned = 50% * (C&I Transport less Cap Exempt)
Short-Term Planning Load = Residential + C&I Sales + Cap Assigned

Table V-12: Design Day Short-Term Planning Load (Dth) - New Hampshire Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Sales + CA
Split Day	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Short-Term Planning Load
2014/15	16,567	17,798	29,554	47,351	10,753	18,801	0	53,166
2015/16	16,744	17,551	30,122	47,673	10,960	19,162	0	53,457
2016/17	17,029	17,629	31,125	48,754	11,325	19,801	0	54,458
2017/18	17,354	17,822	32,206	50,027	11,718	20,488	0	55,663
2018/19	17,684	17,938	33,062	51,000	12,029	21,033	0	56,654
2019/20	17,957	17,774	33,260	51,034	12,101	21,158	0	56,890
CAGR	1.6%	0.0%	2.4%	1.5%	2.4%	2.4%	n/a	1.4%

Cap Exempt = 2014/15 ratio of Cap Exempt to C&I Transport times C&I Transport forecast
Cap Assigned = 100% * (C&I Transport less Cap Exempt); Non-Cap Assigned = 0
Short-Term Planning Load = Residential + C&I Sales + Cap Assigned

The results for each division were tallied to establish Northern's Design Day Short-Term Planning Load, which is provided in Table V-13.

Table V-13: Design Day Short-Term Planning Load (Dth)

	Maine Div.	NH Div.	Northern
Split Day	Short-Term Planning Load	Short-Term Planning Load	Short-Term Planning Load
2014/15	52,990	53,166	106,155
2015/16	54,626	53,457	108,083
2016/17	57,424	54,458	111,882
2017/18	60,435	55,663	116,098
2018/19	63,069	56,654	119,724
2019/20	64,202	56,890	121,091
CAGR	3.9%	1.4%	2.7%

E. Alternative Planning Load

1. Introduction

As explained earlier, Northern provides this Alternative Planning Load case for illustrative and comparative purposes only. Northern submitted a petition to the Maine Public Utilities Commission on May 9, 2014, which included a proposal to discontinue capacity exempt status, while allowing for an exemption from capacity assignment equal to 50 percent of a customer's dual fuel capability. The filing was docketed as Docket 2014-132 and, while Northern's proposal was met with opposition, the matter has not yet been heard by the Maine Commission. In supplemental testimony filed on January 16, 2015, Northern has revised its proposal to provide a capacity exemption equal to 100 percent of a customer's dual fuel capability.

This Company's proposal would replace the current criteria for capacity exempt status, which is whether or not a customer ever purchased supply from the Company (outside of a grace period for new customers), with a new standard that the customer have dual fuel capability. The Company believes there is a significant amount of dual fuel capability among its customers and that it makes sense to leverage those customer resources. Such a change would result in capacity exemption being based on physical resources rather than historical supply purchasing history. Alternative Planning Load would grow as all customer load grows that is not offset by additional dual fuel capability.

Currently, the Company has only limited information of customer dual fuel capability. Therefore, the following calculations reflect the Company's best estimates of dual fuel capability.

2. Alternative Planning Load Calculations

The calculation of Alternative Planning Load is very simple. Total system throughput values are calculated, as was done in Section IV. Then dual fuel capability is estimated and deducted from total system throughput. Alternative Planning Load for Design Year and Design Day is presented below in Table V-14 and Table V-15, respectively.

Table V-14: Design Year Alternative Planning Load (Dth)

	Maine Division			New Hampshire Division			Northern
Split Year	Design Year Throughput	Design Year Dual Fuel	Alternative Planning Load	Design Year Throughput	Design Year Dual Fuel	Alternative Planning Load	Alternative Planning Load
2014/15	12,209,217	2,944,308	9,264,909	7,152,237	1,955,123	5,197,114	14,462,023
2015/16	12,485,598	2,997,957	9,487,641	7,208,003	1,968,411	5,239,592	14,727,233
2016/17	13,156,112	3,153,228	10,002,884	7,360,896	2,013,052	5,347,844	15,350,728
2017/18	13,906,435	3,327,235	10,579,200	7,539,670	2,065,610	5,474,059	16,053,260
2018/19	14,544,520	3,469,949	11,074,571	7,685,450	2,105,782	5,579,668	16,654,239
2019/20	14,719,402	3,490,109	11,229,293	7,719,861	2,107,190	5,612,672	16,841,964
CAGR	3.8%	3.5%	3.9%	1.5%	1.5%	1.6%	3.1%

Alternative Planning Load = System Throughput less Dual Fuel Capability

Table V-15: Design Day Alternative Planning Load (Dth)

	Maine Division			New Hampshire Division			Northern
Split Day	Design Day Throughput	Design Day Dual Fuel	Alternative Planning Load	Design Day Throughput	Design Day Dual Fuel	Alternative Planning Load	Alternative Planning Load
2014/15	83,737	15,445	68,292	63,919	8,056	55,863	124,155
2015/16	85,633	15,726	69,907	64,417	8,111	56,306	126,213
2016/17	90,232	16,541	73,691	65,783	8,295	57,489	131,179
2017/18	95,378	17,454	77,924	67,381	8,511	58,870	136,794
2018/19	99,754	18,202	81,552	68,684	8,677	60,007	141,559
2019/20	100,954	18,308	82,646	68,991	8,683	60,309	142,954
CAGR	3.8%	3.5%	3.9%	1.5%	1.5%	1.5%	2.9%

Alternative Planning Load = System Throughput less Dual Fuel Capability

Again, the actual size and operational state of dual fuel capability among customers is not well known to the Company. The values shown reflect the full consumption of customers believed to have dual fuel capability as of 2014/15 and assume that customers will adopt additional dual fuel capability in relation to Total C&I growth.

F. Comparison of Planning Load Cases

Table V-16 compares the Company-level Design Year Short-Term Planning Load, Alternative Planning Load and System Throughput to Long-Term Planning Load over the planning period. The percentages shown are the average difference between each case over the planning period.

Table V-16: Design Year Planning Load Comparisons (Dth)

		Long-Term v. Short-Term		Long-Term v. Alternative		Long-Term v. Throughput	
Split Year	Long-Term Planning Load	Short-Term Planning Load	Delta	Alternative Planning Load	Delta	Design Year Throughput	Delta
2014/15	11,476,911	12,874,107	-1,397,196	14,462,023	-2,985,111	19,361,454	-7,884,543
2015/16	11,580,067	13,132,597	-1,552,530	14,727,233	-3,147,166	19,693,601	-8,113,534
2016/17	11,723,968	13,619,291	-1,895,323	15,350,728	-3,626,760	20,517,008	-8,793,039
2017/18	11,884,705	14,155,647	-2,270,942	16,053,260	-4,168,555	21,446,105	-9,561,400
2018/19	12,046,344	14,620,572	-2,574,227	16,654,239	-4,607,894	22,229,970	-10,183,625
2019/20	12,179,304	14,807,772	-2,628,468	16,841,964	-4,662,661	22,439,263	-10,259,959
PCT			-15%		-25%		-44%

Table V-17 compares the planning load cases for Design Day over the planning period.

Table V-17: Design Day Planning Load Comparisons (Dth)

		Long-Term v. Short-Term		Long-Term v. Alternative		Long-Term v. Throughput	
Split Year	Long-Term Planning Load	Short-Term Planning Load	Delta	Alternative Planning Load	Delta	Design Day Throughput	Delta
2014/15	96,572	106,155	-9,583	124,155	-27,583	147,656	-51,084
2015/16	97,321	108,083	-10,762	126,213	-28,892	150,050	-52,729
2016/17	98,374	111,882	-13,508	131,179	-32,805	156,015	-57,641
2017/18	99,552	116,098	-16,546	136,794	-37,242	162,759	-63,207
2018/19	100,738	119,724	-18,986	141,559	-40,821	168,438	-67,700
2019/20	101,713	121,091	-19,378	142,954	-41,241	169,945	-68,232
PCT			-13%		-26%		-38%

VI. Current Portfolio

Section VI provides an overview of Northern's current long-term resource portfolio along with narrative descriptions of each resource by capacity path. The overview highlights the amount of long-term capacity under contract by resource type, including whether and how it is assigned to retail marketers under the Delivery Service Terms and Conditions in each state. The overview is followed by resource narratives that describe each path in more detail, including the segments that comprise the path, the supply source accessed, how the resource is utilized (base load supply, balancing, peaking) and how the resource is currently assigned to retail marketers serving delivery service customers.

In addition, Appendix 3 provides capacity path diagrams and tabular lists of contract detail for each path that depict how Northern has combined its pipeline transportation and underground storage contracts, along with the Bay State Gas Company ("Bay State") Exchange Agreement and Granite capacity, in order to move natural gas supplies from various supply sources to Northern's distribution system. The capacity path details provided in Appendix 3 include basic contract information such as product (transportation, storage or exchange), vendor, contract ID number, contract rate schedule, contract end date, contract maximum daily quantity ("MDQ"), contract availability (year-round or winter-only), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point.

A. Overview of Long-Term Resources

Northern has acquired a portfolio of long-term resources for the purpose of satisfying its planning load requirements. The portfolio includes pipeline transportation capacity, underground storage capacity that has been combined with pipeline capacity in order to deliver withdrawn storage to the Company's system and an on-system LNG storage and production facility. As discussed further in Section VII, Resource Balance, the current portfolio does not satisfy Northern's planning load requirements, and so Northern supplements its long-term portfolio with short-term supplies delivered by others to its distribution system or to Granite interconnects ("Delivered Service" or "Delivered Supply").

Northern accesses wholesale natural gas supplies via the following entry points to Northern's distribution system:

- Granite State Gas Transmission ("Granite" or "GSGT") provides transportation capacity that links upstream capacity on PNGTS and TGP to Northern city gates along the Granite system
- Interconnections between Portland Natural Gas Transmission System ("PNGTS") and Granite, located in Westbrook, Maine and Newington, New Hampshire
- Interconnection between Tennessee Gas Pipeline Company ("Tennessee" or "TGP") and Granite, located in Haverhill, Massachusetts or the Northern city-gate with Tennessee, located in Salem, New Hampshire

- Interconnection between Maritimes & Northeast U.S. ("Maritimes" or "MN U.S.") and Granite Located in Westbrook, Maine, or Maritimes' interconnect with Northern's city gate located in Lewiston, Maine
- On-System LNG storage and production facility located in Lewiston, Maine
- Deliveries made by Bay State to Northern's system under the Bay State Exchange Agreement, under which Northern delivers supplies to Bay State's Tennessee or Algonquin city gates and Bay State delivers supplies to Northern's Granite city gates

Northern's long-term resource portfolio is summarized below in Table VI-1, which lists the resources by capacity path as Northern deploys them, the respective MDQ of each path by season, resource type and form of capacity assignment to retail marketers under the Delivery Service tariffs.

Table VI-1: Summary of Northern Resources by Capacity Path (MDQ in Dth)

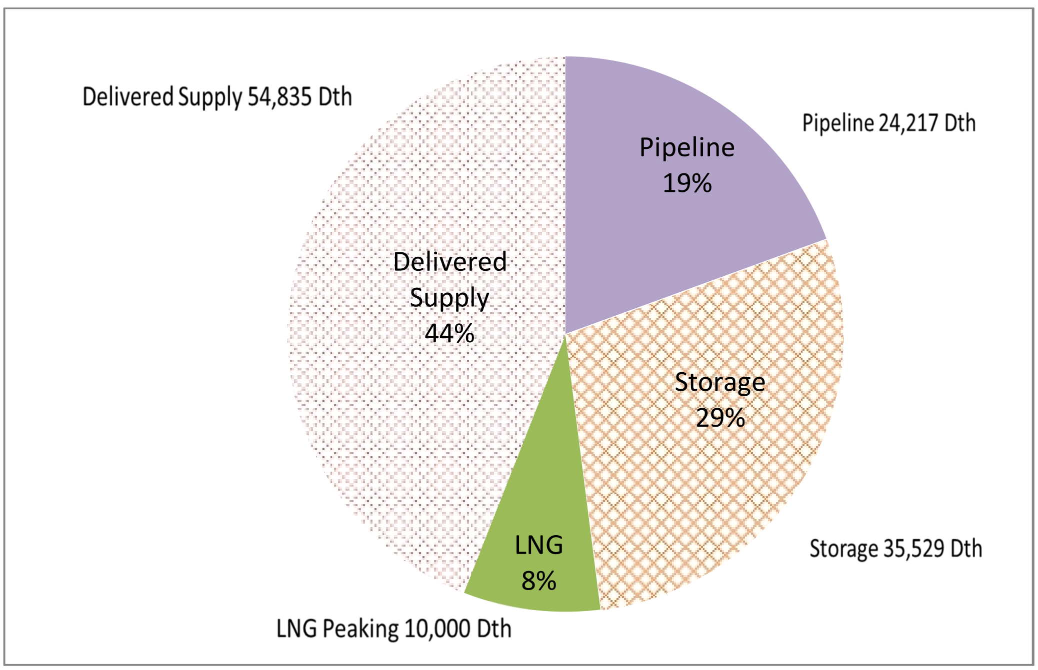
Resource Path	Winter (Nov - Mar)	Summer (Apr - Oct)	Resource Type	ME Form of Assignment	NH Form of Assignment
Chicago Path	6,434	6,434	Pipeline	Not Assigned	Company Managed
PNGTS Year-Round	1,096	1,096	Pipeline	Not Assigned	Capacity Release
Tennessee Niagara	2,327	2,327	Pipeline	Not Assigned	Capacity Release
Tennessee Long-haul	13,109	13,109	Pipeline	Not Assigned	Capacity Release
Algonquin Long-haul	1,251	1,251	Pipeline	Not Assigned	Company Managed
Tennessee Firm Storage	2,644	2,644	Storage	Not Assigned	Capacity Release
Washington 10 Path	32,885	0	Storage	Company Managed	Company Managed
Lewiston LNG Production	4,181	4,181	On-System	Not Assigned	Company Managed
Delivered Winter Baseload	varies	0	Delivered	Not Assigned	Company Managed
Delivered Peaking	varies	0	Delivered	Company Managed	Company Managed

Resource narratives for each long-term resource path listed in Table VI-1 are provided below. Although not listed in the table above, Granite capacity is essential to Northern's portfolio and is used to deliver all of the long-term capacity paths above. Also not listed above is the Bay State Exchange

Agreement, which facilitates in kind deliveries by Bay State to Northern in exchange for supplies Northern delivers to Bay State. Narratives for Granite and the Bay State Exchange Agreement are also provided below. Please note that Table VI-1 lists the MDQ associated with the Lewiston LNG Production facility as 4,181 Dth. Historically, Northern has credited the LNG facility as being capable of producing 10,000 Dth per day of capacity. However, as discussed further in the Lewiston LNG Production narrative, due to the limited on-site storage at the facility, going forward Northern is reducing the amount of capacity from the facility it will rely on for supply planning purposes.

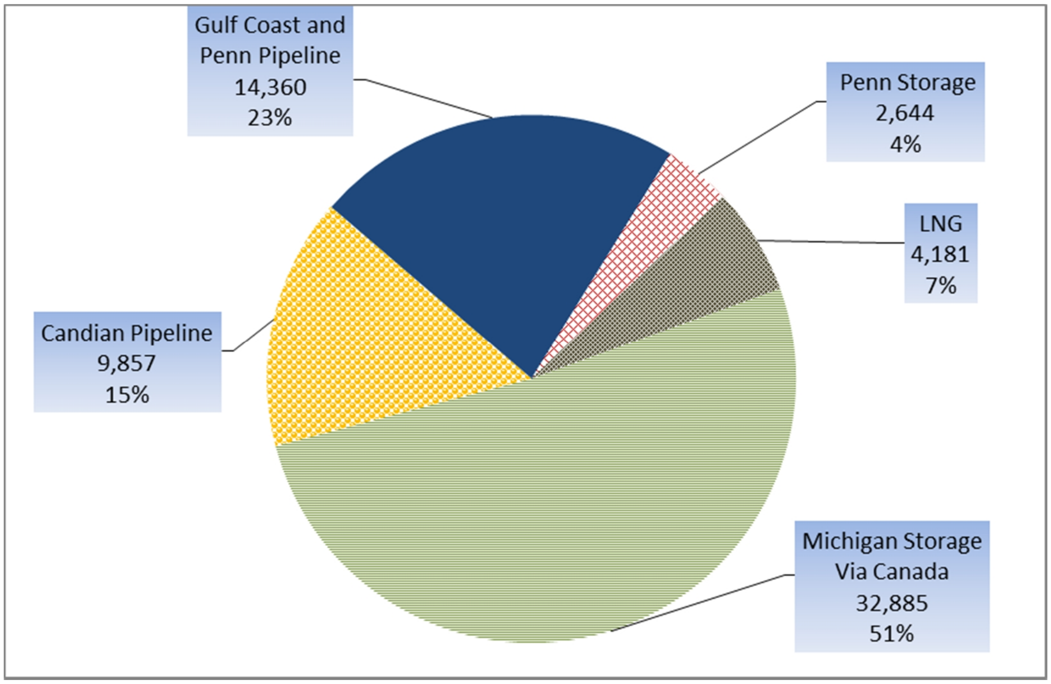
Northern's long-term resources are supplemented with Delivered Supplies that are typically contracted for on a short-term basis in order to meet Northern's winter period planning load requirements. The actual amount of Delivered Supplies varies and is projected year to year. For the winter of 2014/15, Northern has supplemented its long-term portfolio with Delivered Winter Baseload MDQ of 15,000 Dth and Delivered Peaking MDQ of 40,000 Dth, each deliverable to Granite. Combined, the MDQ of these delivered supplies is very significant relative to the MDQ of Northern's long-term resources. Figure VI-1 provides a summary of Northern's 2014/15 winter period portfolio by resource type, including Delivered Supply and LNG at 10,000 Dth, which is consistent with the 2014/15 supply plan.

Figure VI-1: 2014/15 Winter Period Portfolio by Resource Type



Northern seeks to maintain diversity among its long-term resources in terms of delivering upstream pipelines and supply sources. Northern is fed via Canadian supplies delivered from the north (via PNGTS and MN U.S.) and domestic supplies delivered from the south (via TGP), in addition to its on-system peaking facility. A diversified and balanced portfolio provides better reliability and flexibility than relying on a more limited number of supply sources or entry points into the distribution system. In addition, Northern must receive supplies in various points on its system in order to meet load requirements at those locations. Figure IV-2 below summarizes the diversity by supply source of Northern's current long-term portfolio. Please note that in most cases, TGP supplies can either be delivered to the interconnection between Granite and TGP or delivered via the Bay State Exchange Agreement to Bay State's city gate in exchange for deliveries from Bay State to the Northern via the interconnection between Granite and PNGTS.

Figure IV-2: Diversity of Long-Term Capacity by Supply Source (Dth)



B. Existing Resource Narratives

Northern Utilities' long-term resource portfolio is comprised of transportation and underground storage capacity contracts that collectively provide reliable and diversified supply to its system in order to serve planning load requirements. Northern's transportation capacity includes short-haul and long-haul contracts intended to move gas to and from storage, and contracts that are aggregated into defined transportation paths.

As a reference to accompany the existing resource narratives, Table VI-2 provides a listing of Northern's long-term pipeline and underground storage contracts, organized by capacity path, including receipt and delivery zones.

Table VI-2: Pipeline Transportation and Underground Storage Contracts by Capacity Path

Capacity Path	Vendor	Contract ID	Receipt Zone	Delivery Zone
Chicago Path	Vector	FT-1-NUI-0122	Alliance	Dawn
Chicago Path	Vector	FT-1-NUI-C0122	St. Clair (Canada)	Dawn
Chicago Path	Union	M12205	Dawn	Parkway
Chicago Path	TransCanada	41235	Union Parkway Belt	Iroquois
Chicago Path	Iroquois	R181001	Waddington	Wright
Chicago Path	Tennessee	95196	TGP Zone 5	TGP Zone 6
Chicago Path	Tennessee	41099	TGP Zone 5	TGP Zone 6
Chicago Path	Algonquin	93002F	Mendon, MA	Brockton, MA
PNGTS Year-Round	PNGTS	1997-003	Pittsburgh	Granite
Tennessee Niagara	Tennessee	5292	TGP Zone 5	TGP Zone 6
Tennessee Niagara	Tennessee	39735	TGP Zone 5	TGP Zone 6
Tennessee Long-haul	Tennessee	5083	TGP Zone 0	TGP Zone 6
Tennessee Long-haul	Tennessee	5083	TGP Zone L	TGP Zone 6
Algonquin Long-haul	Algonquin	93201A1C	Lambertville, NJ	Taunton, MA
Tennessee Firm Storage	Tennessee	5195	TGP TGP Zone 4	TGP TGP Zone 4
Tennessee Firm Storage	Tennessee	5265	TGP Zone 4	TGP Zone 6
Washington 10 Path	Washington 10	01052	W10 Withdrl Meter	Vector
Washington 10 Path	Vector	CRL-NUI-1096	Alliance	Dawn
Washington 10 Path	Vector	CRL-NUI-1097	Washington 10	Dawn
Washington 10 Path	TransCanada	33322	Union Dawn	East Hereford
Washington 10 Path	PNGTS	1997-004	Pittsburgh	Granite
All Capacity Paths	Granite	14-001-FT-NN	NA	Northern

1. Chicago Path

The “Chicago Path” capacity is one of two “pathed” capacity groupings that combine multiple upstream pipeline segments within Northern’s portfolio. Northern combines Vector, Union, TCPL, Iroquois, TGP, and AGT pipeline transportation capacity within this path, which provides access to attractively priced Chicago index based supply plus applicable fuel and commodity charges necessary to make the ultimate deliveries to TGP and AGT. The capacity path diagram and details for this supply resource are found on page 1 of Appendix 3.

Northern releases this path annually to an asset manager for an asset management fee through an RFP process for a one year term. By releasing this path to an asset manager, Northern bypasses border issues associated with moving gas from Canada to the United States, mitigates the risk associated with trading and scheduling to fill this path of capacity, and maintains access to the delivered product on TGP and AGT at the same prices as if the capacity had not been released. Currently, Northern receives a substantial asset management fee for this path, because asset managers are able to use this capacity freely in the off peak months. In the winter months, Northern utilizes this path by taking daily deliveries up to the amount of the full MDQ to serve its own system at the Pleasant St. Tennessee Z 6 200 Leg city gate, the Bay State Agawam Tennessee zone 6 200 Leg meter, and the Algonquin Bay State Brockton city gate. Deliveries made to Bay State city gates are reciprocated by deliveries from Bay State to Northern under the Bay State Exchange Agreement. Northern typically base loads this resource for most of the winter period.

In the New Hampshire Division, Northern assigns portions of the Chicago Path to retail marketers as a company-managed supply. In the Maine Division, this capacity is not assigned to retail marketers but the demand and commodity pricing associated with this path are factored into the price of the resources that are assigned.

2. PNGTS Year-Round

In addition to the seasonal firm capacity that Northern has on the Portland Natural Gas Transmission System, Northern has a year round firm contract on PNGTS. This contract allows Northern to receive gas at either its primary receipt meter at Pittsburg, NH or at the Westbrook, ME interconnect between Maritimes and PNGTS on a secondary firm basis. From there, Northern delivers gas to the interconnections between PNGTS and Granite State at Westbrook (primary firm), Newington (secondary firm), or Eliot (secondary firm).[118] Northern receives those deliveries on its corresponding firm Granite capacity to effectuate deliveries to Northern's city gates. The capacity path diagram and details for this supply resource are found on page 2 of Appendix 3.

Supply at Pittsburg, NH is Canadian supply sourced from the TransCanada interconnect with PNGTS at East Hereford in Quebec. Supply at the Westbrook, ME interconnect between Maritimes and PNGTS[119] is sourced from Maritimes supplies located in the off-shore region of eastern Canada and from LNG supplies delivered to the Canaport facility in New Brunswick.

Northern currently manages this capacity directly, rather than releasing it to an asset manager. Currently, the capacity has relatively little value within the context of asset management due to excess capacity on PNGTS, but can provide Northern flexibility to seamlessly move supplies between the three interconnections between PNGTS and Granite, in order to provide an additional tool for balancing supply with demand behind each of these meters. Typically, Northern will base load this resources for a majority of the winter.

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118 Please note that PNGTS has never restricted the use of secondary points.

119 Please note the interconnection between Maritimes and PNGTS, referred to as "Westbrook," is a different meter than the interconnection between PNGTS and Granite, also referred to as "Westbrook." In order to move natural gas from the interconnection between Maritimes and PNGTS at Westbrook into Granite at Westbrook, one needs either to use PNGTS capacity to move the gas away from the PNGTS-Maritimes interconnection into the PNGTS-Granite interconnection or utilize the Maritimes Westbrook lateral for an additional fee.

In the New Hampshire Division, Northern releases portions of this capacity to retail marketers under its Delivery Service Tariff. In the Maine Division, this capacity is not assigned to retail marketers but the demand and commodity pricing associated with this path are factored into the price of the resources that are assigned.

3. Tennessee Niagara

Northern has entitlements on two transportation contracts on Tennessee with primary receipts at Niagara in zone 5 on the 200 leg, and primary deliveries to zone 6 on the 200 leg at Bay State city gates and Pleasant Street, the interconnection with Granite in Haverhill, Massachusetts. Northern receives the deliveries on TGP to Pleasant Street on its corresponding firm Granite State capacity for transport on Granite to Northern city gates. The capacity path diagram and details for this supply resource are found on page 3 of Appendix 3.

These contracts are aggregated within Northern's portfolio and released to an asset manager in an annual RFP process. During the winter months, the total MDQ of both contracts is available to Northern. Northern typically base loads this resource for most of the winter period.

In the New Hampshire Division, Northern releases portions of this capacity to retail marketers under its Delivery Service Tariff. In the Maine Division, this capacity is not assigned to retail marketers but the demand and commodity pricing associated with this path are factored into the price of the resources that are assigned.

4. Tennessee Long-haul

Northern has one long-haul transportation contract on Tennessee Gas Pipeline, which allows Northern to deliver up to 13,155 Dth into Granite. The primary receipt points within this contract are located throughout the Gulf zones 0 and 1 on the 100, 500, and 800 legs. Primary delivery meters on this contract are in zone 6 on the 200 leg at Pleasant Street and Bay State's city gates as well as in zone 4 on the 300 leg at the injection meter for TGP's Northern Storage - FS-MA. The capacity path diagram and details for this supply resource are found on page 4 of Appendix 3.

Northern releases a portion of this contract annually to an asset manager, and uses the remaining portion to fulfill baseload requirements. The portion that is asset managed is available for next day calls in the winter months. To fill the remaining capacity, Northern uses Gulf or zone 4 200 leg supplies, which are both in path to the delivery meters. Northern typically base loads this resource for a majority of the winter period.

In the New Hampshire Division, Northern releases portions of this capacity to retail marketers under its Delivery Service Tariff. In the Maine Division, this capacity is not assigned to retail marketers but the demand and commodity pricing associated with this path are factored into the price of the resources that are assigned.

5. Algonquin Long-haul

Northern's Algonquin contract provides primary rights to receive gas supply at the interconnection between Algonquin and Texas Eastern ("TETCO") pipeline in TETCO's Zone M3 at Lambertville, NJ and at the interconnect between Algonquin and Transco in Zone 6 at Centerville, NJ. This capacity has primary delivery rights to Bay State's Algonquin city-gate at Taunton, MA. Northern utilizes this capacity as a winter baseload in order to supply the Bay State Exchange. The capacity path diagram and details for this supply resource are found on page 5 of Appendix 3.

In the New Hampshire Division, Northern assigns portions of this capacity to retail marketers as a company-managed supply. In the Maine Division, this capacity is not assigned to retail marketers but the demand and commodity pricing associated with this path are factored into the price of the resources that are assigned.

6. Tennessee Firm Storage

Northern has firm underground storage entitlements on the Tennessee system in zone 4 on the 300 leg in Pennsylvania. Northern's maximum storage quantity is 259,337 Dth, and the withdrawal quantity is up to 4,243 Dth/day. Northern injects ratably in the summer months to fill this storage space. In the winter months, Northern withdraws this supply to make deliveries to Northern's city gate in zone 6 using Tennessee's transportation contract No. 5265.[120] The primary receipt meter in this transportation contract is the FS-MA storage withdrawal meter, and the primary delivery meter is at Pleasant Street in Z6 on the 200 leg, the interconnection between TGP and Granite State. Northern receives this gas on its corresponding firm Granite capacity to make deliveries on Granite State to Northern city gates. The capacity path diagram and details for this supply resource are found on page 6 of Appendix 3.

In the New Hampshire Division, Northern releases portions of this capacity to retail marketers under its Delivery Service Tariff. In the Maine Division, this capacity is not assigned to retail marketers but the demand and commodity pricing associated with this path are factored into the price of the resources that are assigned.

7. Washington 10 Path

The "Washington 10 Path" is another pathed capacity grouping within Northern's portfolio. The capacity path diagram and details for this supply resource are found on page 7 of Appendix 3. Northern combines Vector, TransCanada and PNGTS transportation capacity with Washington 10 storage capacity in order to deliver supplies to the interconnections between PNGTS and Granite. This capacity grouping is considered the core of Northern's resource portfolio, because Northern's 3.4 BCF of storage space at the Washington 10 storage cavern in Michigan is Northern's largest long-term supply resource as shown in Figure VI-2. Storage is filled with Chicago indexed supply, which is attractively priced. The associated

[120] Maximum delivery quantity on this contract is 2,653 Dth.

pipeline capacity allows for ultimate deliveries of up to 33,000 Dth/day on PNGTS. This path is released to an asset manager annually for a one year term in exchange for an asset management fee. Releasing this capacity to an asset manager allows Northern to bypass Canadian border issues and avoid trading and scheduling risks. During the summer months, the asset manager ratably fills the storage for Northern. During the winter months, Northern relies upon the asset manager to effectively deliver storage gas from Washington 10 along the Vector, TransCanada, and PNGTS pipelines. Northern takes delivery of this gas at interconnects between PNGTS and Granite State, and pays the asset manager for the storage as it is withdrawn plus the applicable commodity-based costs of moving the gas from Washington 10 to the interconnection with GSGT. Washington 10 storage provides commodity at a known price during the heating season.

Northern assigns portions of this capacity to retail marketers as company-managed supply under the Delivery Service Tariffs in both the New Hampshire Division and the Maine Division.

8. Lewiston LNG Production

The Lewiston LNG facility is an important and effective resource within Northern's portfolio that offers Northern numerous advantages not available from other supply resources. One advantage is a level of flexibility that cannot be attained by the pipeline delivered supplies in the portfolio. For example, while the pipeline supplies require steady takes over the course of the gas day (10 am – 10 am EST), Northern is able to run the plant as needed so that volumes can be produced for a portion of the day or across gas days as needed. In addition to using the LNG facility as a peaking supply for the winter's coldest days, Northern utilizes this flexibility in order to meet intraday needs, to get through morning pulls and Monday mornings that are colder than originally forecasted when weekend gas was procured. The Lewiston LNG facility does have limited on-site storage capacity, which means that most of the LNG vaporized during winter is purchased at winter prices. To mitigate exposure to price spikes, Northern typically seeks first of month index pricing. The capacity path diagram and details for the LNG plant are found on page 8 of Appendix 3.

Northern has historically relied upon the LNG facility to be able to produce 10,000 Dth per day. However, Northern is concerned about the limited on-site storage capacity, which is approximately 12,000 Dth, or at most 1.2 days of supply. Producing 10,000 Dth on a single day would require 11 truckloads to refill the storage consumed, which is not feasible within a day, especially during peak winter weather when traveling conditions could be poor. If storage could not be substantially replenished that day, the facility could not produce a substantial volume the following day. Given these dynamics, going forward Northern is reducing the daily production capacity of the facility for supply planning purposes to 4,181 Dth, which reflects 3 days of storage and about 4 to 5 truckloads to replenish.

In the New Hampshire Division, Northern assigns portions of this capacity as company-managed supply to retail marketers under its Delivery Service Tariff. In the Maine Division, neither LNG costs nor capacity are currently assigned to retail marketers.

9. Granite State Gas Transmission

Northern utilizes its Granite transportation capacity in order to deliver all of its transportation and underground storage supply resources with the exception of those delivered under the Bay State Exchange Agreement, which is delivered to Northern's city-gates by Bay State. Granite is an affiliate of Northern, and both are subsidiaries of Unitil Corporation. Granite operates an 87-mile pipeline, extending from Haverhill, Massachusetts, through New Hampshire to just northwest of Portland, Maine, and has no on-system storage or compressor stations.

Granite has five receipt meters. The Westbrook receipt meter interconnects with PNGTS and MN U.S. The Newington and Eliot receipt meters interconnect with PNGTS. The Pleasant St. and Salem St. receipt meters interconnect with Tennessee Gas Pipeline.

GSGT has thirty-six delivery meters on its system, each of which is a Northern city-gate. Seventeen of these meters deliver to the New Hampshire Division and nineteen deliver to the Maine Division. In the New Hampshire Division, Northern releases portions of this capacity to retail marketers, under the terms of its Delivery Service Tariff, as part of the capacity paths that are released and also utilizes this capacity as part of company managed supply provided to retail marketers. In the Maine Division, a portion of this capacity is utilized to provide company managed supply to retail marketers. The cost of this capacity is factored into the price of the assigned resources in the Maine Division.

In the New Hampshire Division, Northern releases portions of its Granite capacity as part of released capacity paths and also assigns portions of its Granite capacity as company-managed supply to retail marketers under its Delivery Service Tariff. In the Maine Division, Granite capacity is not assigned to retail marketers but the demand costs are factored into the price of the resources that are assigned.

10. Bay State Exchange Agreement

The Bay State Exchange Agreement is an agreement under which Northern Utilities delivers its firm Tennessee and Algonquin transportation entitlements to Bay State's city gates at Agawam and Lawrence on Tennessee Gas Pipeline and Brockton and Taunton on Algonquin pipeline in exchange for deliveries from Bay State to Northern's city gates located along the Granite State pipeline. Both parties benefit from this exchange as a means of delivering supply to their respective systems without having to contract for additional firm pipeline capacity, allowing each to make the best use of assets that do not access their own distribution system. The parties have mutually agreed to base load summer volumes of 4,100 Dth/day and winter volumes of 12,000 Dth/day, which are subject to adjustment as mutually agreed. Northern requires the Bay State Exchange Agreement in order to deliver portions of the Chicago and Niagara supply resources. However, Northern may also elect to utilize the Bay State

Exchange for the purpose of delivering Tennessee Long-haul or Tennessee FS-MA supply resources to Bay State in order to effectuate deliveries into the northern portion of Northern's system (deliveries via PNGTS). The Exchange Agreement has been in place since December 2008, when Unitil purchased Northern from Bay State. The Agreement does have a 180 day termination notice provision, so it could be terminated by either party. Northern is not aware of any plans on the part of Bay State to terminate.

VII. Resource Balance

Section VII provides information showing the difference between the Long-Term Planning Load forecast, as determined in Section V, and the capacity of Northern's existing long-term resources, which is known as the Resource Balance. Separate comparisons are provided, based on Normal Year requirements, Design Year requirements and Design Day requirements. Although Northern evaluates the adequacy of its long-term portfolio relative to its Long-Term Planning Load forecast, for illustrative purposes only, the capacity of the existing portfolio is also compared to the Short-Term Planning Load and Alternative Planning Load forecasts. Please note that the Resource Balance tables for Normal and Design Year are provided to comply with the IRP requirements and may not be determinative with respect to overall portfolio surplus or deficiency.

Table VII-1 lists the maximum daily quantity (MDQ) and annual contract quantity (ACQ) of the long-term resources in Northern's portfolio by season. Resources are organized by path, consistent with the resource descriptions provided in Section VI, Current Portfolio. Pipeline resources are assumed to be available at the MDQ every day of the year, so the Winter ACQ reflects 151 days at the MDQ and the Summer ACQ reflects 214 days at the MDQ. Storage resources are assumed to be limited to the maximum storage capacity under contract and available only in winter. On-System LNG is assumed to provide up to 15 days of service during the winter period and to cover boil off in summer.

Table VII-1: Northern Long-Term Resources by Capacity Path (Dth)

Resource Path	Winter MDQ (Nov - Mar)	Summer MDQ (Apr - Oct)	Winter ACQ (Nov - Mar)	Summer ACQ (Apr - Oct)	Annual ACQ
Chicago Path	6,434	6,434	971,534	1,376,876	2,348,410
PNGTS Year-Round	1,096	1,096	165,496	234,544	400,040
Tennessee Niagara	2,327	2,327	351,377	497,978	849,355
Tennessee Long-haul	13,109	13,109	1,979,459	2,805,326	4,784,785
Algonquin Long-haul	1,251	1,251	188,901	267,714	456,615
Tennessee Firm Storage	2,644	0	259,337	0	259,337
Washington 10 Path	32,885	0	3,400,000	0	3,400,000
Lewiston LNG Production	4,181	4,181	62,715	15,000	77,715
Existing Long-Term Capacity	**63,927**	**28,398**	**7,378,819**	**5,197,438**	**12,576,257**

The Resource Balance analysis provides guidance as to the adequacy of the current portfolio and the level of additional long-term resources that may be required to reliably and cost-effectively meet Northern's planning load during the five-year planning period (i.e., the 2015/16 gas year through the 2019/20 gas year) covered in this IRP.

A. Normal Year Planning Load Resource Balance

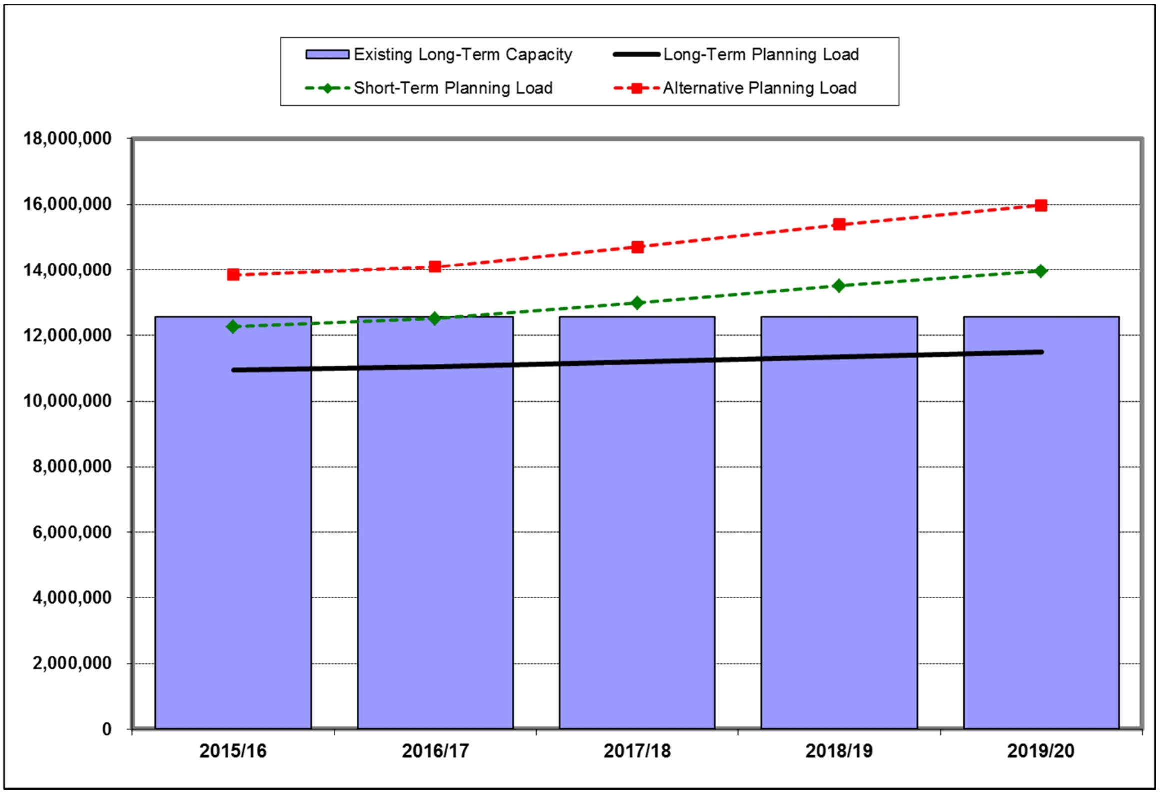
In calculating Resource Balance, Northern assumes renewal or replacement of all existing long-term resources. The reasons for this are that the U.S. pipelines capacity in the portfolio is fully or largely depreciated resulting in rates that are typically very low relative to new capacity resources. Further, although Canadian pipeline rates are cost of service based and may not reflect heavily depreciated historical cost, Northern highly values its underground storage that is delivered via Canadian transportation and access to new underground storage is very limited. Lastly, existing contracts with both PNGTS and TGP physically delivery into Granite, which is critical for Northern.

Table VII-2 provides the Normal Year Resource Balance over the planning horizon and Figure VII-1 depicts the data graphically. The comparisons show that Northern has a positive resource balance throughout the planning period with respect to the Long-Term Planning Load forecast. As discussed with regard to the resource data presented in Table VII-1, pipeline volumes are assumed to flow 365 days per year. While annual resource balance calculations provide indications of the adequacy of existing resources, they can be deceiving because they mask the relative timing of resource needs and availability of resources. For example, there can be times (particularly in summer) when daily throughput falls below the level of existing resource capacity, but other times (particularly in winter) when daily throughput is much higher than the level of existing resource capacity. Since excess capacity on a summer day cannot be used to serve a deficiency on a winter day, there may still be a resource shortfall.

Table VII-2: Normal Year Resource Balance (Dth)

	2015/16	2016/17	2017/18	2018/19	2019/20
Existing Long-Term Capacity	12,576,257	12,576,257	12,576,257	12,576,257	12,576,257
Long-Term Planning Load	10,946,267	11,046,555	11,185,621	11,341,337	11,497,793
Normal Year Resource Balance	**1,629,990**	**1,529,702**	**1,390,636**	**1,234,920**	**1,078,464**
Existing Long-Term Capacity	12,576,257	12,576,257	12,576,257	12,576,257	12,576,257
Short-Term Planning Load	12,264,301	12,509,950	12,981,218	13,503,848	13,956,746
Resource Balance	311,956	66,307	(404,961)	(927,591)	(1,380,489)
Existing Long-Term Capacity	12,576,257	12,576,257	12,576,257	12,576,257	12,576,257
Alternative Planning Load	13,842,667	14,093,491	14,701,024	15,389,463	15,978,004
Resource Balance	(1,266,410)	(1,517,234)	(2,124,767)	(2,813,206)	(3,401,747)

Figure VII-1: Chart of Normal Year Resource Balance (Dth)



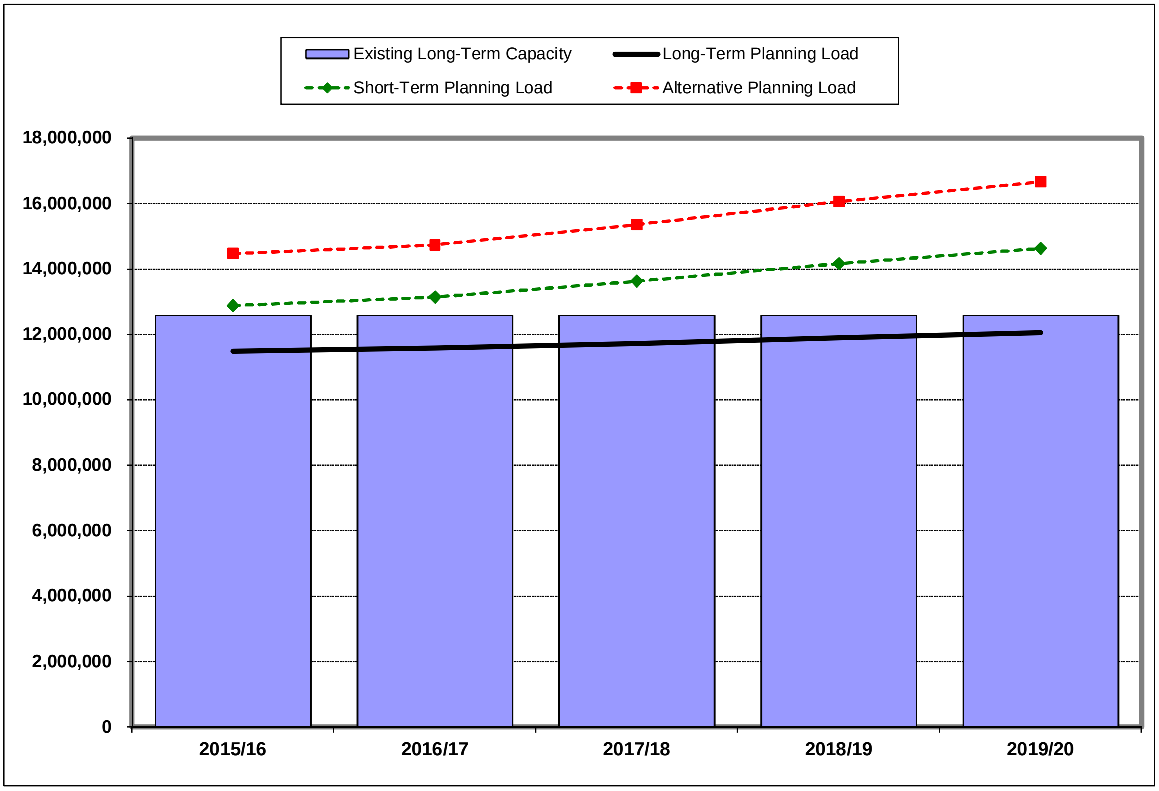
B. Design Year Planning Load Resource Balance

Table VII-3 provides the Design Year Resource Balance over the planning horizon and Figure VII-2 depicts the data graphically. Similar to the Normal Year Resource Balance, the comparison of long-term capacity resources to Design Year planning load shows that Northern has a positive resource balance throughout the planning period with respect to the Long-Term Planning Load forecast. Again, since the annual resource balance calculation does not recognize the respective timing of planning load need or resource availability, there may still be a resource shortfall.

Table VII-3: Design Year Resource Balance (Dth)

	2015/16	2016/17	2017/18	2018/19	2019/20
Existing Long-Term Capacity	12,576,257	12,576,257	12,576,257	12,576,257	12,576,257
Long-Term Planning Load	11,476,911	11,580,067	11,723,968	11,884,705	12,046,344
Design Year Resource Balance	**1,099,346**	**996,190**	**852,289**	**691,552**	**529,913**
Existing Long-Term Capacity	12,576,257	12,576,257	12,576,257	12,576,257	12,576,257
Short-Term Planning Load	12,874,107	13,132,597	13,619,291	14,155,647	14,620,572
Resource Balance	(297,850)	(556,340)	(1,043,034)	(1,579,390)	(2,044,315)
Existing Long-Term Capacity	12,576,257	12,576,257	12,576,257	12,576,257	12,576,257
Alternative Planning Load	14,462,023	14,727,233	15,350,728	16,053,260	16,654,239
Resource Balance	(1,885,766)	(2,150,976)	(2,774,471)	(3,477,003)	(4,077,982)

Figure VII-2: Chart of Design Year Resource Balance (Dth)



C. Design Day Planning Load Resource Balance

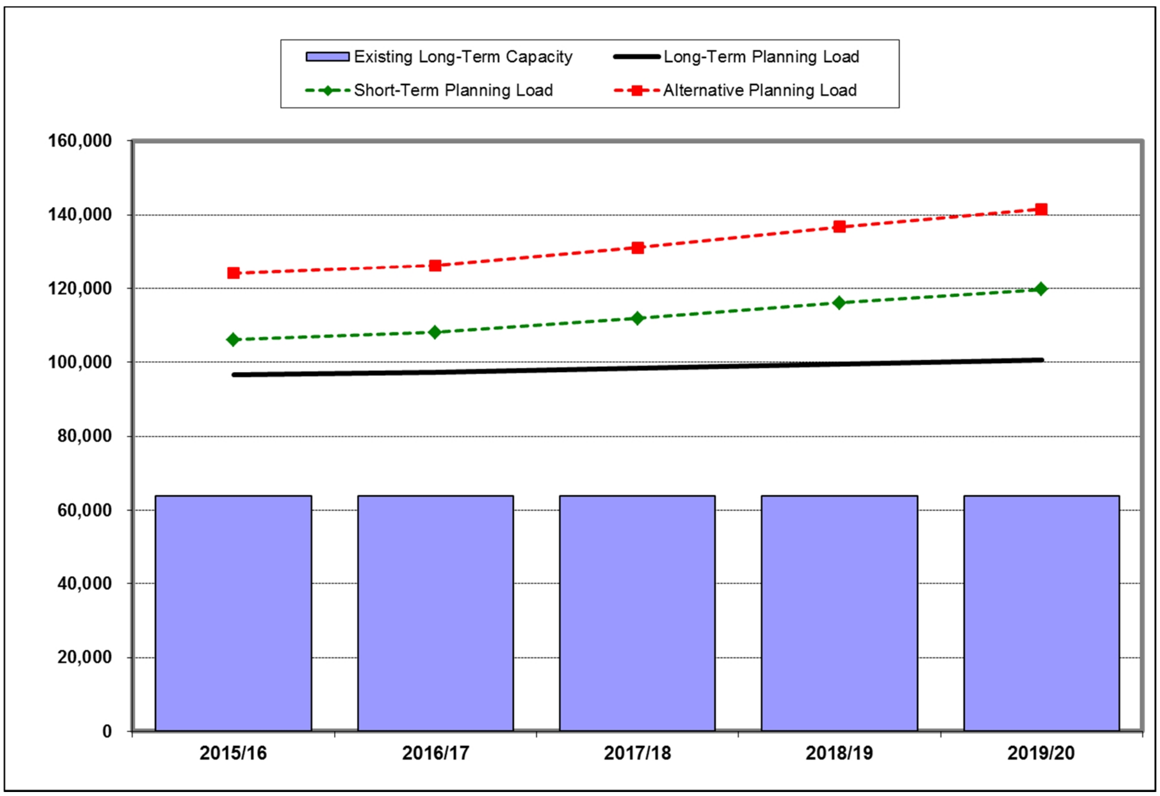
In order to align the timing of resource need with resource availability, the resource balance is was also prepared under Design Day conditions. Table VII-4 provides the Design Day Resource Balance over the planning horizon and Figure VII-3 depicts the data graphically.

Table VII-4: Design Day Resource Balance (Dth)

	2015/16	2016/17	2017/18	2018/19	2019/20
Existing Long-Term Capacity	63,927	63,927	63,927	63,927	63,927
Long-Term Planning Load	96,572	97,321	98,374	99,552	100,738
Design Day Resource Balance	**(32,645)**	**(33,394)**	**(34,447)**	**(35,625)**	**(36,811)**
Existing Long-Term Capacity	63,927	63,927	63,927	63,927	63,927
Short-Term Planning Load	106,155	108,083	111,882	116,098	119,724
Resource Balance	(42,228)	(44,156)	(47,955)	(52,171)	(55,797)
Existing Long-Term Capacity	63,927	63,927	63,927	63,927	63,927
Alternative Planning Load	124,155	126,213	131,179	136,794	141,559
Resource Balance	(60,228)	(62,286)	(67,252)	(72,867)	(77,632)

The Design Day comparison of planning load and available resources tells a much different story than did the annual comparisons, indicating that Northern's long-term resources are not adequate to meet Long-Term Planning Load under design day conditions. Specifically, Northern's long-term resources are projected to be short of Long-Term Design Day Planning Load by 32,645 Dth in 2015/16 and the deficit grows to 36,811 Dth by 2019/20. The stark differences between the annual resource balance and design day resource balance calculations highlight Northern's lack of long-term peaking capacity and the low load factor characteristics of demand on Northern's system. Currently, Northern purchases delivered supplies on a short-term basis to meet peak day requirements above the level of existing resources. In Section IX, Preferred Portfolio, planning load requirements are looked at more closely using load duration curves and other tools.

Figure VII-3: Chart of Design Day Resource Balance (Dth)



VIII. Incremental Supply Resources

In Section VIII, Northern identifies reasonably available supply resource options that could meet the portfolio needs identified in the Resource Balance Section. Those needs are refined further in Section IX, Preferred Portfolio.

Northern identifies new supply alternatives by staying informed on developments within the regional natural gas market. In order to stay informed on both market and regulatory developments, Northern is a member of the Northeast Gas Association ("NGA"), the American Gas Association ("AGA") and Alberta Northeast Gas ("ANE") and also participates with other LDCs in New England in various matters of common interest. Northern also subscribes to natural gas market periodicals, such as Bentek and Platt's *Gas Daily*, and monitors pipeline Electronic Bulletin Board ("EBB") postings for additional information that may affect the natural gas market. Most importantly, Northern maintains business relationships with pipelines and suppliers serving the Northeast and attends the regional events such as markets forums and the annual LDC Forum. These activities help Northern to identify developers and projects that could meet the needs Northern may require.

A. Pending Contract Renewal Decisions

All long-term contracts in Northern's resource portfolio are up for renewal during the five year planning period.

As mentioned in Section VII, Northern anticipates renewing all contracts primarily because: (i) as illustrated in this IRP, Northern requires the capacity to meet Planning Load; (ii) legacy capacity is heavily depreciated and therefore much less expensive than new capacity; (iii) certain of the pipeline capacity contracts are used to deliver storage volumes, which provide Northern with additional price stability among other benefits; and (iv) certain of the pipeline capacity is physically connected to Northern (or Granite) or is used to effectuate the swap arrangement. Moreover, once turned back, legacy capacity typically cannot be reacquired. Northern will also look for opportunities to replace capacity, but unless replacement capacity takes the form of new agreements with existing vendors there is risk that the timing of conversion to replacement capacity could be out of sync with termination of existing resources such that either too much or too little capacity is under contract for a period of time. Northern values its underground storage and resources that already physically deliver to its system and so is likely to renew such contracts.

Under the National Energy Board decision in the recent TransCanada tolls application, authority was granted to TransCanada allowing them to require existing shippers along a path that TransCanada plans to expand via new construction to increase the term of their contracts. Northern anticipates that contract 33322 will be subject to such a "term up" requirement in the near future.

Table VIII-1 lists the contracts, which are grouped by resource path as presented in Section VI, Current Portfolio, along with their termination dates and minimum renewal periods.

Table VIII-1: End Dates and Renewal Terms of Existing Long-Term Resources

Path ID	Segment ID	Capacity Path	Vendor	Contract ID	End Date	Miniumum Renewal Term
1	1	Chicago Path	Vector	FT-1-NUI-0122	3/31/2016	n/a
1	2	Chicago Path	Vector	FT-1-NUI-C0122	3/31/2016	n/a
1	3	Chicago Path	Union	M12205	10/31/2017	1 year
1	4	Chicago Path	TransCanada	41235	10/31/2017	5 years
1	5	Chicago Path	Iroquois	R181001	10/31/2017	1 year
1	6	Chicago Path	Tennessee	95196	10/31/2017	5 years
1	6	Chicago Path	Tennessee	41099	10/31/2017	5 years
1	7	Chicago Path	Algonquin	93002F	10/31/2016	1 year
2	1	PNGTS Year-Round	PNGTS	1997-003	3/9/2019	1 year
3	1	Tennessee Niagara	Tennessee	5292	3/31/2020	5 years
3	1	Tennessee Niagara	Tennessee	39735	3/31/2020	5 years
4	1	Tennessee Long-haul	Tennessee	5083	10/31/2018	5 years
4	1	Tennessee Long-haul	Tennessee	5083	10/31/2018	5 years
5	1	Algonquin Long-haul	Algonquin	93201A1C	10/31/2016	1 year
6	1	Tennessee Firm Storage	Tennessee	5195	3/31/2020	5 years
6	2	Tennessee Firm Storage	Tennessee	5265	3/31/2020	5 years
7	1	Washington 10 Path	Washington 10	01052	3/31/2018	negotiable
7	2	Washington 10 Path	Vector	CRL-NUI-1096	10/31/2017	n/a
7	2	Washington 10 Path	Vector	CRL-NUI-1097	3/31/2017	n/a
7	3	Washington 10 Path	TransCanada	33322	3/31/2018	5 years
7	4	Washington 10 Path	PNGTS	1997-004	3/9/2019	1 year
8	1	All Capacity Paths	Granite	14-001-FT-NN	10/31/2015	1 year

B. New Potential Supply Resources

The following sections discuss in detail certain potential supply resources, which Northern considers viable alternatives to serving Northern's markets in Maine and New Hampshire. In addition, Appendix 4 provides the NGA's Summary of Planned Enhancements, Northeast Natural Gas Pipeline Systems.

Northern anticipates that the pipeline transportation resources described below would be used primarily to access to base load supply and would be assigned to transportation customers in the New Hampshire Division only, although the costs of demand and commodity would be reflected in the cost of storage and peaking resources provided to transportation customers in the Maine Division. Projects with U.S. paths would be assigned to New Hampshire customers via capacity release. If new on-system LNG vaporization and storage capacity were added to Northern's system, such a resource would provide peaking supply. Northern would expect to assign any new LNG capacity to transportation customers in New Hampshire as a Company-managed supply. Currently, LNG is not subject to assignment in the Maine Division. However, if significant on-site storage were part of a new on-system LNG facility, such a resource might be subject to assignment in the Maine Division since prior to their expiration, the long-term "Wells Replacement" contracts, which provided fixed prices during the winter period, were subject to assignment in the Maine Division.

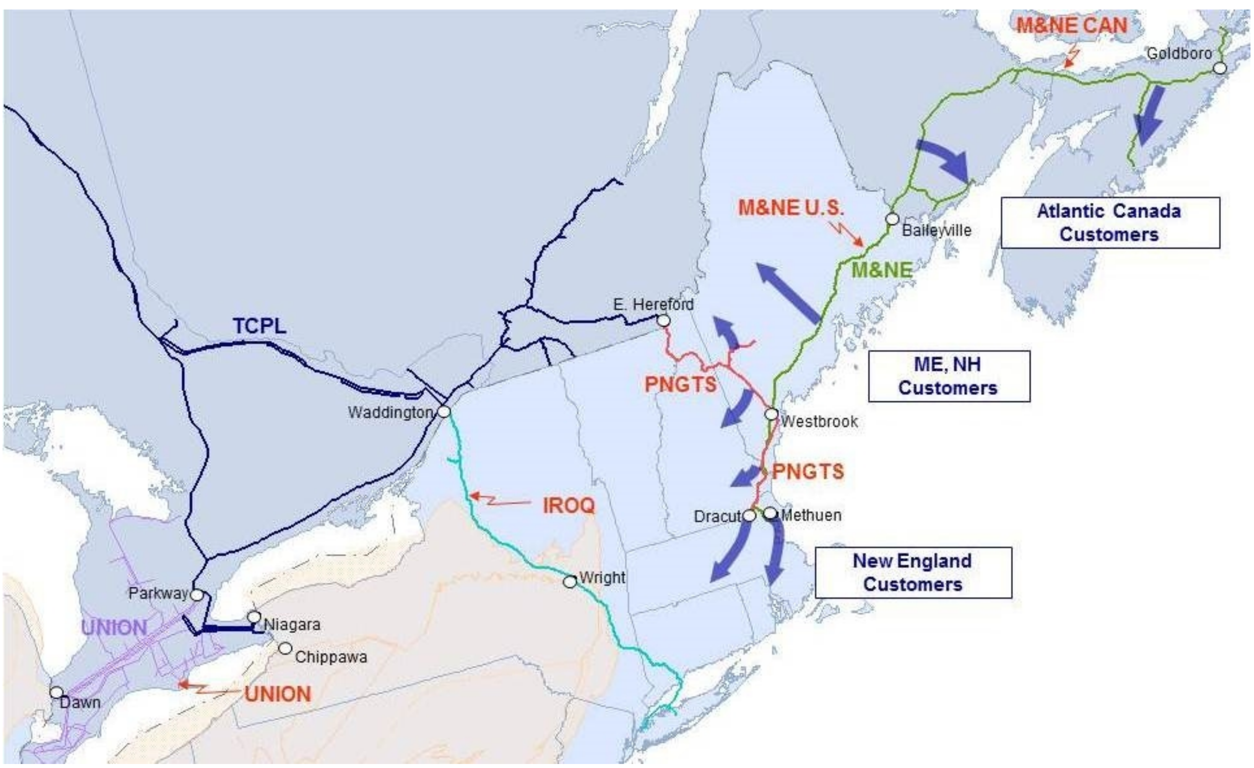
1. Supply Sources from the "North"

As discussed previously in Section VI, Northern currently accesses supplies from the "North" via PNGTS and M&NP. A detailed review of the potential supply sources and/or projects under development by PNGTS and M&NP are provided below.

a) PNGTS – Continent-to-Coast Expansion Project

As shown in Figure VIII-1 below, the proposed PNGTS C2C Project would provide incremental firm transportation capacity from Pittsburg, New Hampshire (i.e., the interconnection point with the TCPL Mainline) to any delivery point up to and including Westbrook, Maine (i.e., the interconnection point with the PNGTS/M&NP Joint Facilities), with an option to deliver to any point on the PNGTS/M&NP Joint Facilities from Westbrook, Maine to Dracut, Massachusetts. The PNGTS C2C Project would provide an incremental 167,000 Dth/day of capacity from Pittsburg to Westbrook; the capacity to Dracut on the PNGTS/M&NP Joint Facilities would remain at the current level of 210,000 Dth/day.[121]

Figure VIII-1: PNGTS C2C Project[122]



121 See, Portland Natural Gas Transmission System, "Portland Natural Gas Transmission System's Continent to Coast Expansion Project, Open Season Notice for Firm Service from December 3, 2013 to January 24, 2014".

122 Source: PNGTS website.

As indicated to the MPUC in the ECRC proceeding, PNGTS, in conjunction with TCPL and Iroquois, proposes three alternative transportation routes as part of the C2C Project. Specifically, these alternative routes include: (i) from Wright, New York on Iroquois to interconnect with the TCPL Mainline at Waddington, New York and from the TCPL Mainline to interconnect with PNGTS at East Hereford, (ii) from Dawn, Ontario on the TCPL Mainline to interconnect with PNGTS at East Hereford, or (iii) from Chippawa or Niagara on the TCPL Mainline to interconnect with PNGTS at East Hereford.[123] The C2C Project would not require any construction on PNGTS; however, it would require an expansion upstream (i.e., TCPL Mainline/TQM), as well as other system modifications on the TCPL Mainline and Iroquois.[124] The estimated daily reservation rate on the PNGTS component of the various routes (i.e., the C2C Project rate) is $0.60/Dth,[125] with a required minimum commitment term of 15 years and a proposed in-service date of November 1, 2017.[126]

The initial open season for the PNGTS C2C Project closed on June 28, 2013, and there has not been any public announcements regarding shipper interest. In early December 2014, PNGTS indicated a new open season for the PNGTS C2C Project will be held in January 2015, which will align with open seasons by TransCanada, Union Gas, and Iroquois (which are discussed in detail below).[127]

b) TransCanada 2017 New Capacity Open Season

As discussed, in alignment with the PNGTS C2C Project, TransCanada is currently holding an open season for new firm transportation service on the TCPL Mainline, with an in-service date of November 1, 2017 (i.e., the "2017 NCOS"). As outlined in the 2017 NCOS notice, short- and long-haul firm transportation services are being offered for a minimum term of 15 years from the Empress, Niagara Falls, Chippawa, Parkway, and Iroquois receipt points to any delivery point on the TCPL Mainline system at the transportation tolls submitted to the NEB in the TCPL Mainline Settlement application. Shippers will also have an option of converting existing long-haul firm transportation contracts to short-haul service contracts. Upstream and/or downstream transportation services (if needed) will be contracted for separately (i.e., directly with Union, Iroquois and/or PNGTS). The 2017 NCOS is scheduled to close on January 30, 2015.[128]

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123 See, Portland Natural Gas Transmission System, ECRC Proposal, MPUC Docket No. 2014-00071, December 5, 2014, at 5.

124 See, Portland Natural Gas Transmission System, "Portland Natural Gas Transmission System's Continent to Coast Expansion Project, Open Season Notice for Firm Service from December 3, 2013 to January 24, 2014".

125 Ibid.

126 See, Portland Natural Gas Transmission System, ECRC Proposal, MPUC Docket No. 2014-00071, December 5, 2014, at 5.

127 See, Portland Natural Gas Transmission System, ECRC Proposal, MPUC Docket No. 2014-00071, December 5, 2014, at 7; and TransCanada PipeLines Limited, "TransCanada's Firm Transportation New Capacity Open Season", December 12, 2014.

128 See, TransCanada PipeLines Limited, "TransCanada's Firm Transportation New Capacity Open Season", December 12, 2014.

c) *Union Gas Dawn to Parkway Firm Transportation Open Season*

Union Gas is currently offering incremental firm capacity for a minimum term of 15 years along three transportation paths; specifically, (i) Dawn to Parkway, (ii) Dawn to Kirkwall, and (iii) Kirkwall to Parkway (see Figure VIII-2 below). As indicated in the open season notice, incremental capacity of up to 650,000 GJ/day will be available in November 2017, and 550,000 GJ/day in November 2018. Rates are proposed to be in accordance with the existing Union Gas M12 and M12-X rate schedules. Similar to TransCanada's 2017 NCOS, the binding open season bids are due by January 30, 2015.[129]

Figure VIII-2: Union Gas System[130]

d) *Iroquois South-to-North Project*

Iroquois initially held an open season for the South-to-North ("SoNo") Project in late 2013/early 2014 in conjunction with an open season on TransCanada and the initial open season for the PNGTS C2C Project.[131] As proposed, the SoNo Project would reverse flows on the Iroquois system in order to transport natural gas supplies to Waddington, New York (i.e., the interconnection with the TCPL Mainline). Specifically, as shown in Figure VIII-3 below, the proposed SoNo Project will transport up to 300,000 Dth/day of natural gas supplies from interconnections with Dominion at Canajoharie, New York,

129 See, Union Gas, "Dawn to Parkway Firm Transportation Open Season", December 12, 2014.

130 Ibid.

131 Please note that the proposed SoNo Project rates from the initial open season held in late 2013/2014 from the Wright, New York receipt point were $0.22/Dth for anchor shippers and $0.27/Dth for non-anchor shippers. See, Iroquois Gas Transmission System, "South-to-North Project Open Season", December 3, 2013.

Constitution Pipeline at Wright, New York, and Algonquin at Brookfield, Connecticut and deliver to points within Iroquois' Zone 1 and to the interconnect with TransCanada at Waddington, New York.[132]

Figure VIII-3: Iroquois SoNo Project – Proposed Route

As discussed previously, PNGTS has announced that an open season on Iroquois will be held in January 2015 in alignment with the open seasons for the PNGTS C2C Project and TCPL 2017 NCOS.[133]

2. Supply Sources from the "South" and "West"

As discussed previously in Section III, there are several pipeline infrastructure projects proposed to deliver supplies from the Marcellus Shale into the New England and Atlantic Canada region. As part of its review of natural gas supply resource alternatives, Northern summarizes below certain natural gas pipeline projects proposed to provide more access to the Marcellus and Utica Shale basins from the "South" and "West". Specifically, the Company reviewed:

- Kinder Morgan – Northeast Energy Direct Project;
- Spectra Energy – Atlantic Bridge; and
- Spectra Energy/Northeast Utilities/Iroquois – Access Northeast.

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132 See, Iroquois Gas Transmission System, "South-to-North Project Open Season", December 3, 2013.

133 See, Portland Natural Gas Transmission System, ECRC Proposal, MPUC Docket No. 2014-00071, December 5, 2014, at 7.

a) Kinder Morgan – Northeast Energy Direct Project

Tennessee, a subsidiary of Kinder Morgan, has proposed the construction of a new interstate pipeline system into the New England region referred to as the NED Project. Specifically, Kinder Morgan has proposed two components for its NED Project, specifically: (i) the "Supply Path" is the proposed path from the existing Tennessee 300 Line in Pennsylvania to Wright, New York (i.e., the interconnection point with Iroquois and the proposed Constitution Pipeline); and (ii) the "Market Path" is the proposed path from Wright, New York to Dracut, Massachusetts (i.e., the interconnection point with M&NP-US) as illustrated in Figure VIII-4 below.[134]

Figure VIII-4: NED Project – Supply and Market Paths[135]

The Supply Path of the NED Project will consist of approximately 32 miles of pipeline looping segments along Tennessee's 300 Line; approximately 235 miles of greenfield pipeline from the existing 300 Line to Tennessee's 200 Line at Wright, New York; upgrades to existing compressor stations; and two new compressor stations. The Supply Path will deliver supplies from the Marcellus production area to interconnections with Iroquois, the proposed Constitution Pipeline project, and/or Tennessee's

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[134] See, Kinder Morgan, Draft Environmental Report, Resource Report 1, FERC Docket No. PF14-22-000, December 8, 2014.

[135] Source: Kinder Morgan website.

system near Wright, New York. The proposed capacity on the NED Supply Path is from 800,000 Dth/day up to 1,000,000 Dth/day.[136]

The Market Path of the NED Project will consist of approximately 188 miles of new and co-located mainline from Wright, New York to an interconnect with the M&NP/PNGTS Joint Facilities at Dracut, Massachusetts, as well as Tennessee's existing 200 Line near Dracut, Massachusetts; pipeline laterals as necessary; modifications to existing facilities; and additional meter and compressor stations. The 188 miles of mainline pipeline includes approximately 53 miles of pipeline generally co-located with Tennessee's existing 200 Line and an existing power utility corridor in western New York; approximately 64 miles of pipeline generally co-located with an existing power utility corridor in Massachusetts; and approximately 71 miles of pipeline generally co-located with an existing power utility corridor in southern New Hampshire (i.e., approximately 90% of the route will be within or along existing rights-of-way).[137]

As indicated in Kinder Morgan's proposal to the MPUC in the ECRC proceeding, the targeted project size for the NED Project is 800,000 Dth/day;[138] however, the NED Project is scalable up to 2,200,000 Dth/day.[139] The estimated capital cost for the NED Market Path is approximately $1.75 to $2.75 billion.[140]

In late July 2014, Kinder Morgan announced nine initial anchor shippers on the Market Path of the NED Project; specifically, The Berkshire Gas Company; Columbia Gas of Massachusetts; National Grid; Connecticut Natural Gas Corporation; Southern Connecticut Gas Corporation; Liberty Utilities (EnergyNorth Natural Gas) Corp.; City of Westfield Gas and Electric Light Department; and two other undisclosed LDCs. Combined, these nine LDCs have a total capacity commitment of 500,000 Dth/day on the NED Market Path.[141]

Kinder Morgan has submitted the project for pre-filing review by the FERC in September 2014, and has indicated that it plans to file its major permit applications in September 2015 in order to commence construction of the NED Project in January 2017. The anticipated in-service date for the NED Project is November 1, 2018.[142]

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136 See, Kinder Morgan, Draft Environmental Report, Resource Report 1, FERC Docket No. PF14-22-000, December 8, 2014.

137 See, Kinder Morgan, "Tennessee Gas Pipeline Adopts New Routes via Existing Utility Corridors in New Hampshire and New York for Proposed Northeast Energy Direct Project", December 5, 2014.

138 See, Kinder Morgan, ECRC Proposal of Tennessee Gas Pipeline Company, L.L.C., MPUC Docket No. 2014-00071, December 4, 2014, at 29.

139 See, Kinder Morgan, Draft Environmental Report, Resource Report 1, FERC Docket No. PF14-22-000, December 8, 2014.

140 See, Kinder Morgan, "Natural Gas Pipelines", presentation at the 2014 Analysts Conference, January 30, 2014, at 19.

141 See, Kinder Morgan Energy Partners, L.P., "Kinder Morgan Energy Partners Announces Initial Anchor Shippers for Northeast Energy Direct Project", July 30, 2014; and Kinder Morgan, Draft Environmental Report, Resource Report 1, FERC Docket No. PF14-22-000, December 8, 2014.

142 See, Kinder Morgan, Draft Environmental Report, Resource Report 1, FERC Docket No. PF14-22-000, December 8, 2014.

b) Spectra Energy – Atlantic Bridge

The Atlantic Bridge project proposed by Spectra Energy is an expansion of the Algonquin and M&NP interstate pipeline systems, which will be able to provide approximately 240,000 Dth/day of incremental capacity from interconnections with Millennium Pipeline Company, L.L.C. ("Millennium") at Ramapo, New York and Tennessee at Mahwah, New Jersey to existing and new delivery points along the Algonquin and M&NP-US systems. Specifically, the proposed project will consist of loop and replacement on the Algonquin pipeline, a majority of which will be within existing rights-of-way, and related facilities as needed; and bidirectional flow modifications on the M&NP-US system. In addition, the Atlantic Bridge project will add new compression at Weymouth, Massachusetts which will allow physical delivery from Algonquin to the M&NP-US system.[143]

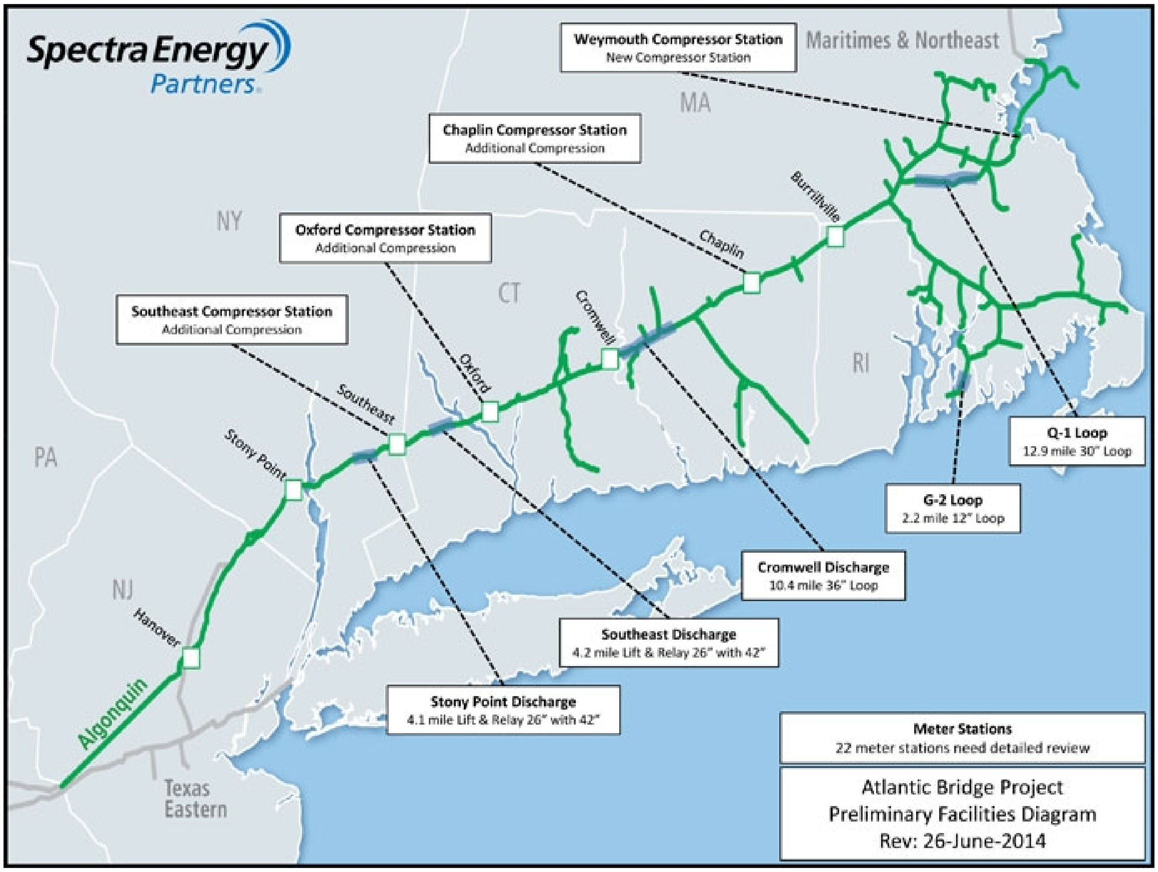
An open season for the Atlantic Bridge project was conducted in early 2014, with an expected in-service date of November 1, 2017.[144] Capital expenditures for the Atlantic Bridge project are estimated to be approximately $900 million.[145] Figure VIII-5 below shows the proposed facilities for the Atlantic Bridge project.

[143] See, Spectra Energy, Proposal for an Energy Cost Reduction Contract Submitted to the Maine Public Utilities Commission, December 5, 2014, at 17-20.

[144] See, Spectra Energy, "Spectra Energy to Expand Pipeline Systems in New England", Press Release, February 5, 2014.

[145] See, Spectra Energy, "Meeting Maine's Natural Gas Infrastructure Needs", Presentation at the Maine Natural Gas Conference, October 9, 2014, at 13.

Figure VIII-5: Atlantic Bridge – Proposed Project Facilities[146]



c) Spectra Energy/Northeast Utilities/Iroquois – Access Northeast

The Access Northeast expansion project proposed by Spectra Energy, Northeast Utilities, and Iroquois will deliver supplies from multiple receipt point options along the Algonquin and Iroquois pipeline systems to serve both power generation and LDC demand requirements in the New England region. The Access Northeast project proposes to offer an "Electric Reliability Service", which involves a combination of firm pipeline transportation service and LNG peaking service utilizing market area storage facilities. The proposed receipt points for Access Northeast include: the Algonquin interconnects with Tennessee at Mahwah, New Jersey, Millennium Pipeline at Ramapo, New York, and Iroquois at Brookfield, Connecticut; and the proposed delivery points include the various power plant aggregation areas in order to provide direct delivery to natural gas-fired power plants on Algonquin, M&NP and Iroquois.[147]

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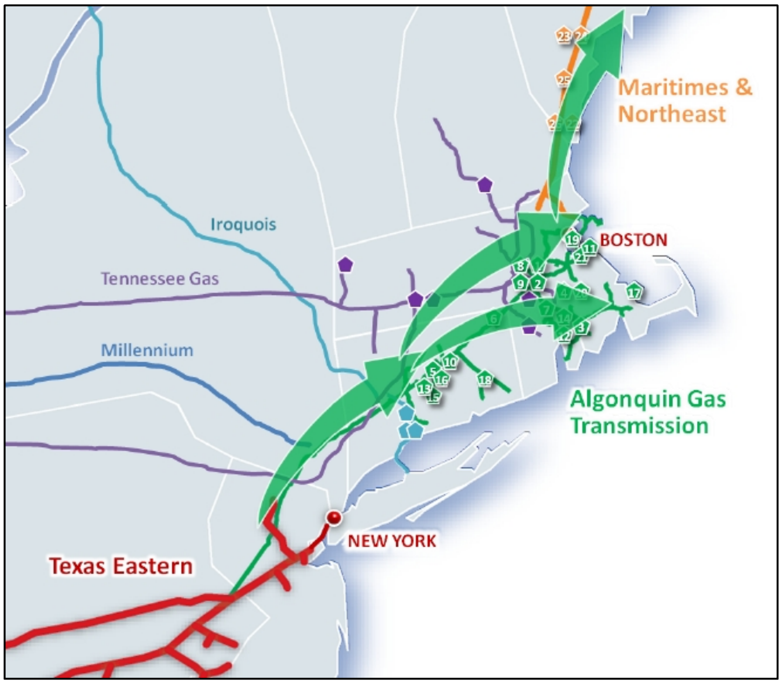
146 Source: Spectra Energy website.

147 See, Spectra Energy, "Spectra Energy and Northeast Utilities Form Alliance with Iroquois Gas Transmission for Access Northeast Project", December 8, 2014; and Spectra Energy, Proposal for an Energy Cost Reduction Contract Submitted to the Maine Public Utilities Commission, December 5, 2014, at 6

Figure VIII-6: Proposed Access Northeast Project[148]



The proposed capacity on the Access Northeast is scalable up to 900,000 Dth/day, and is expected to be placed in-service as early as November 1, 2018.[149] The Access Northeast project will include replacement of existing portions of the Algonquin mainline with larger diameter pipe, as well as meter station upgrades as needed; and modifications on the M&NP system, such as enhancements to allow for bidirectional flow and modifications to existing laterals and meter stations.[150] The capital costs for the Access Northeast project is expected to be approximately $3 billion.[151]

Expressions of interest in the Access Northeast project were solicited in the September to October 2014 timeframe; and the project sponsors expect to file regulatory applications by early 2015.[152] In addition, Spectra Energy has indicated an open season will be held in the first quarter of 2015 for capacity on the Access Northeast project.[153]

As discussed above, there are certain pipeline expansion projects that provide context for some of the potential projects reviewed, each of which are discussed below.

148 Source: Spectra Energy, Proposal for an Energy Cost Reduction Contract Submitted to the Maine Public Utilities Commission, December 5, 2014, at 6.

149 Ibid.

150 Ibid.

151 See, Spectra Energy, "Spectra Energy and Northeast Utilities Announce New England Reliability Solution", Press Release, September 16, 2014.

152 See, Spectra Energy, "Spectra Energy & Northeast Utilities Announce Access Northeast – New England Energy Reliability Solution", Project Brochure, September 16, 2014.

153 See, Spectra Energy, Proposal for an Energy Cost Reduction Contract Submitted to the Maine Public Utilities Commission, December 5, 2014, at 8.

3. Potential On-System Supply Facilities

In addition to inter-state pipeline projects, the Company may also explore the development of on-system resources to meet a portion of the identified planning load shortfall. Specifically, Unitil has the option of developing on-system liquefied natural gas vaporization and storage facilities to provide peaking supplies during high demand winter days. Given that much of the planning load not met with existing resources is a peaking need, expanded on-system production facilities would appear to be a complementary addition to the long-term resource portfolio.

These types of facilities can be designed to meet various demand requirements including two or three days of needle peaking supply or thirty days of winter period supply. Depending on the design of the on-system LNG facility, storage inventory (e.g., summer re-fill) could be supplied by: (i) liquefying pipeline natural gas that was delivered to the LNG facility; and /or (ii) purchasing LNG from third-parties and trucking the product to the LNG facility.

Regardless of re-fill approach (i.e., liquefy or purchase from a third party) an LNG facility with adequate on-site storage could provide increased price stability as the re-fill process would take place in the off-peak period. Specifically, Unitil would refill the LNG inventory during the off-peak period at prices that reflect the summer market conditions (i.e., minimal demand for heat-sensitive customers). As a result, the Company would have a supply resource (i.e., the LNG inventory) to dispatch during the peak period, but the cost of that resource would not be based on the peak day or winter season natural gas prices, similar to the pricing provided by underground storage.

In addition, an on-system LNG facility could increase the overall flexibility of the gas supply portfolio as the dispatch of an on-system LNG facility is not subject to the tariff of an upstream pipeline. Specifically, to manage operations, an upstream pipeline will have nomination and scheduling procedures, which may have certain limits (e.g., hourly ratable flow requirements). As such, hourly demand fluctuations (e.g., weather is colder than forecasted) that are addressed by adjustments to upstream pipeline flows need to be managed within the structure of the upstream pipeline tariff provisions. An on-system LNG facility would not be subject to an upstream pipeline tariff and the dispatch of the LNG inventory would be under the control of the Company. As a result, an on-system LNG facility provides the Company with increased flexibility such as non-ratable production.

Finally, an on-system LNG facility, depending on the location, may provide operation benefit such as pressure support on peak hours.

IX. Preferred Portfolio

Section IX provides an overview of the Company's approach to long-term portfolio planning and reviews the evaluation methods the Company uses to identify resource needs and compare competing long-term resources. The Company's primary goal with respect to the Integrated Resource Plan is to communicate its long-term resource decision making process.

As discussed in Sections III and VIII, the natural gas market, from both a regional and North American perspective is undergoing significant change. Specifically, certain natural gas supply basins and sources are in decline, while other basins and sources have experienced rapid growth. As a result, LDCs have an opportunity to review and assess various pipeline projects and the potential impact of these projects on the natural gas supply portfolio. Due to ongoing negotiations and current open seasons, the Integrated Resource Plan does not select or propose any specific project or resource for addition to the long-term portfolio. In addition, state-level regulatory issues could impact Northern's contracting decisions. Therefore, this Preferred Portfolio section focuses on the goals of the planning process, the identified resource need and evaluation tools the Company may use.

A. Approach to Long-Term Planning

Prior to a review of the Company's evaluation methods, the major objective of an LDC portfolio is discussed. In general, an LDC develops a resource portfolio to meet forecasted demand requirements in a reliable manner at a reasonable cost. An LDC meets this objective through various strategies, including:

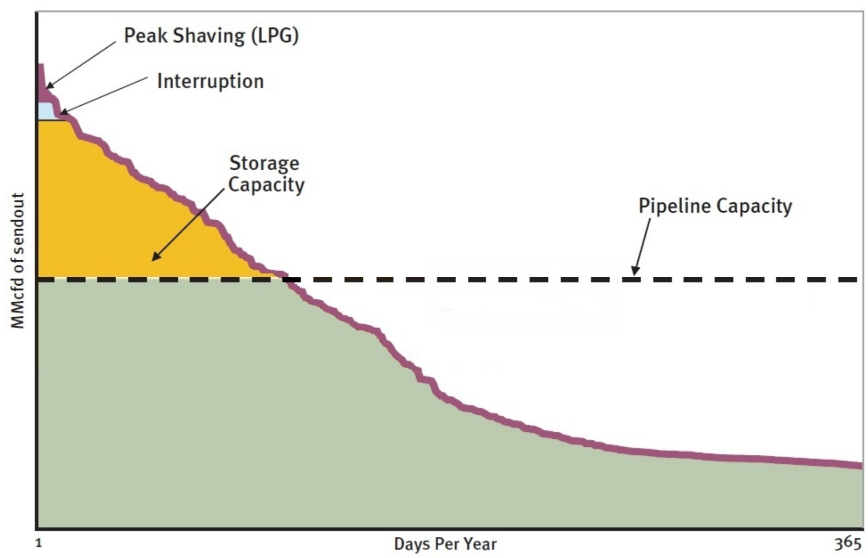
- Secure reliable contract(s) for gas supply and firm transport;
- Diversify resources across types (e.g., storage vs. flowing supply), pipelines, and supply basins;
- Diversify price signals (e.g., different purchase locations, use of storage, use of LNG) to provide stability of price;
- Construct peaking facilities or contract for various services to flexibly manage demand/weather swings or operational issues; and
- Ensure deliverability of gas supplies to various LDC points to maintain system pressures and integrity.

Although the above strategies are generally pursued by LDCs, the unique circumstance of a specific LDC will also influence how the gas supply portfolio is developed and maintained. Specifically, certain factors influence how an LDC may develop its asset portfolio, including:

<u>Customer composition</u>: Each LDC will have a unique composition of customer segments (e.g., residential, commercial, industrial, and power generation). As such, the LDC load profile will reflect this customer composition. For example, an LDC with a significant level of heat-sensitive residential and commercial customers will have a high winter demand; while an LDC with many industrial customers will have more year-round demand. Therefore, the LDC demand requirement has peak, seasonal and year-

round demand components. A load duration curve, such as the illustrative one shown in Figure IX-1 below, sorts the daily natural gas demand from highest to lowest volume and identifies the type of resource typically used to meet various portions of demand. As illustrated in Figure IX-1, pipeline capacity is generally contracted to meet year-round demand needs (i.e., the green highlighted area); the yellow highlighted area under the load duration curve is that part of the LDC demand that is typically served by storage resources; while peaking resources (e.g., LNG or LPG) are used to meet peaking requirements.

Figure IX-1: Illustrative Load Duration Curve[154]



Source: Based on representative industry data

Services: LDCs typically offer bundled sales service and unbundled transportation service. In addition, an LDC may provide non-firm service or other customer segment specific services (e.g., special contracts for high load customers).

Geographic location: The specific geographic location of an LDC will influence how the natural gas portfolio is developed. For example, an LDC located in a natural gas supply basin with access to various pipelines may opt for a short-term capacity contracting strategy to take advantage of the pipeline-on-pipeline competition. Conversely, an LDC located at the end of the pipeline (i.e., not near natural gas supply resources) may implement a long-term contract to secure that capacity.

Regulatory precedent: The past rulings and findings of the appropriate state utility commissions will affect how the LDC develops its portfolio. For example, one state may require certain planning standards for determining weather conditions, and, therefore, demand. Similarly, a state may have unique objectives that need to be addressed and implemented by the LDC.

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[154] Source: Federal Energy Regulatory Commission, “Current State of and Issues Concerning Underground Natural Gas Storage”, FERC Docket No. AD04-11-000, September 30, 2004, at 24 [modified by Sussex].

While each LDC has the general objective of providing reliable service at a reasonable cost, the circumstances of the individual LDC will influence how that objective is achieved.

From Northern's perspective, the development of the Marcellus and Utica Shale basins, and the numerous proposed pipeline infrastructure projects, provides the Company with an opportunity to review and assess the impact of these projects on the long-term portfolio. In addition, the Company recognizes that it has a significant peaking demand on its system and very limited on-system peaking resources, thus the potential construction of peaking facilities is another opportunity the Company is exploring. Lastly, the reduced availability of certain supplies that are declining (i.e., SOEP) or have alternative market options (i.e., imported LNG) going forward will likely impact pricing and availability of delivered supplies, creating additional risk.

As discussed, the objective of Northern's portfolio planning process is to provide reliable service to customers at a reasonable cost. To achieve this objective, within shifting market, operational and regulatory conditions, the Company has developed a portfolio that is diverse (i.e., various pipeline paths are under contract); has access to several gas supply basins (e.g., Gulf of Mexico, Marcellus/Utica, Dawn/Chicago Hubs); and is comprised of various assets (i.e., flowing supplies, natural gas storage, and LNG facilities). The Company recognizes that, over time, there may be a need to replace and/or adjust paths or assets in the portfolio as market, operational or regulatory conditions warrant and, as such, Northern utilizes the following resource evaluation process to develop and maintain the portfolio.

B. Resource Evaluation Methods

The Company utilizes both quantitative and qualitative approaches to review the different aspects of potential new resources.

Although the Preferred Portfolio (i.e., the combination of existing and incremental resources that meets forecasted loads over the planning period in a reliable manner at a reasonable cost) may need to be changed or adjusted over time to meet changes in customer, operational, market or regulatory conditions, the Company utilizes the following analytical framework to inform portfolio decisions.

- Resource Balance Assessment – Broadly identify incremental resource needs by comparing existing long-term resources to long-term planning load requirements, under the various weather and growth scenarios.
- Identify Incremental Resource Need – Utilize various analysis tools (e.g., Sendout® model or load duration curves) to quantify the volume requirement as well as the timing of the resource need.
- Identify Proxy Resources – Results of the Incremental Resource Need Assessment are then used to define "Proxy Resources". Depending on the type of resource need indicated, hypothetical resource additions are developed and modeled as resource additions. For

example, such a resource addition might be 10,000 Dth of pipeline capacity or 20,000 Dth of on-system peaking capacity. Proxy Resources are added to Sendout® and the model results are evaluated to determine favorable resource types and quantities to seek from available projects.

- Landed Cost Analysis – A landed cost analysis is developed to compare and screen various resource project options.
- Modeled Cost Analysis – Once specific projects are identified and the attributes and terms are known, then they are modeled in Sendout®. The primary output for decision-making purposes is total delivered portfolio cost, utilization rate for proposed new resource and impact on utilization rate of other resources.
- Qualitative Assessment – Review and comparison of competing projects on basis of non-price characteristics to assess value of competing projects; characteristics include feasibility, viability, and contribution to portfolio diversity, location of delivery, contractual issues, etc.
- Decision-Making Process – Decisions regarding proposed resource additions are based primarily on qualitative criteria so long as the modeled cost of competing projects is comparable. This approach favors fundamentals that cannot be modeled quantitatively, such as locational diversity, viability and contracting issues. This approach also acknowledges that price forecasts change and reduces the possibility that major resource decisions are based primarily on such forecasts.

Each of these steps described above are described further or demonstrated. The Resource Balance Assessment was demonstrated in Section VII. The steps of identifying Incremental Resource Need, identifying Proxy Resources and the Modeled Cost Analysis are demonstrated or discussed below in Part C, Indicated Resource Need. Landed Cost Analysis, Qualitative Assessment and Decision-Making Process are described further below.

1. Landed Cost Analysis

From a quantitative perspective, a landed cost analysis evaluates the delivered cost of various natural gas supply paths to a specific point. The typical landed cost approach assumes that the pipeline demand charges are evaluated at a 100% load factor (i.e., the transportation path is used every day at full volume) and variable and/or fuel charges are based on full contracted volumes. This approach allows multiple paths to be evaluated and compared in a transparent manner. Table IX-1 illustrates a generic (i.e., hypothetical) landed cost approach.

Table IX-1: Illustrative Landed Cost Approach

1	2	3	4		3+4
Path	Gas Supply Basin	Gas Supply Cost	Pipeline 1	Pipeline 2	Total
A	WCSB	Henry Hub + x	$D	N/A	Henry Hub + x + $D = A Total
B	Gulf of Mexico	Henry Hub + y	$E	$F	Henry Hub + y + $E + $F = B Total
C	Marcellus Shale	Henry Hub – z	$G	N/A	Henry Hub – z + $G = C Total

As shown in Table IX-1, the landed cost approach consists of four components: 1) alternative paths to transport gas supply to a specific point are identified; 2) the gas supply basin associated with each transportation path is identified; 3) the gas supply cost is calculated for each path in terms of Henry Hub plus or minus a basis differential; and 4) the transportation cost (i.e., demand, variable and fuel) for all pipelines within the path is calculated. Finally, the total landed cost for each path is calculated (i.e., the gas supply cost plus the total transport costs).

For example, as demonstrated in Table IX-1, Path A consists of a WCSB gas supply, which is priced at Henry Hub plus a basis differential of "x" and is transported on Pipeline 1 for a total landed cost comprised of the gas supply cost (i.e., "Henry Hub + x") and the transportation cost for Pipeline 1 (i.e., "$D"). Similarly, Path B consists of a Gulf of Mexico gas supply transported on both Pipeline 1 and Pipeline 2 for a landed cost comprised of the gas supply cost (i.e., "Henry Hub + y") plus total transport cost on Pipeline 1 and Pipeline 2 (i.e., "$E + $F"). Finally, Path C consists of a Marcellus Shale gas supply, which is priced at Henry Hub minus a basis differential of "z" and is transported on Pipeline 1 for a total landed cost comprised of the gas supply cost (i.e., "Henry Hub – z") and the transportation cost for Pipeline 1 (i.e., "$G").

To evaluate various natural gas supply resources on an initial quantitative basis, the landed cost analysis is used to calculate the delivered costs of alternative supply paths to Northern's service territory. The approach to assumptions and calculations the Company uses to conduct the landed cost analysis are discussed further below.

The first step in developing the landed cost analysis is to identify alternative gas supply options and transportation paths to Northern's service territory. For each supply option, the supply cost in terms of Henry Hub plus or minus a basis differential is estimated. The next step is to calculate the pipeline transportation cost for each transportation path, based upon proposed project rates, such as may be provided in a capacity open season notice, or internal estimates. Variable and fuel costs for each alternative transportation path are typically based upon tariff rates or capacity open season notice. The landed cost approach assumes that the pipeline demand charge is evaluated at a 100% load factor (i.e., the transportation path is used every day at full volume) and variable and/or fuel charges are based on full contracted volumes.

2. Qualitative Assessment

Northern also utilizes a qualitative analysis to assess resource projects. The qualitative analysis allows the Company to evaluate and assess pipeline projects across various metrics, including:

Upstream/Downstream Issues: Pipeline projects will not only be assessed on their own merits, but will also include a review of issues on pipelines that are either upstream or downstream of the pipeline project under review. For example, a review of an expansion on Pipeline A that receives all of its natural gas supply from Pipeline B necessitates a need to review the attributes of Pipeline B.

Project Development Risks: Each pipeline project, or on-system peaking facility project, will likely present a unique set of commercial and regulatory issues that need to be assessed. The evaluation of these issues and the ability of the development company to address each issue will be included as part of the analysis of project development risk.

Pipeline Regulatory Environment: Each pipeline project will likely be influenced by current regulatory issues facing the pipeline. For example, a rate/toll offered for a certain expansion project may be conditioned on other pending rate/toll filings (e.g., cost allocation proceeding).

Contributions to Diversity: The Company seeks and values diversity among supply basins and diversity among delivering pipelines. Pipeline projects that add diversity by providing access to gas supply areas to which the Company has limited access are likely to add value to the portfolio. Similarly, projects that deliver along paths where the Company currently has limited volume can improve reliability of supply by adding diversity to the mix of delivering pipelines the Company relies upon.

Rate/Toll and Cost Sharing: Pipeline projects may provide potential shippers with options regarding rates/tolls. For example, a pipeline may offer a fixed toll for a set time period with a construction cost sharing mechanism; or a cost of service toll, which could change over time. The flexibility and transparency of the pipeline rate/toll approaches will be considered in the qualitative analysis.

Contract Structure: The complexity of the pipeline contract approach is another consideration in the qualitative assessment. For example, a precedent agreement with numerous terms and conditions will need to be balanced against the optionality provided by those terms and conditions. The balance of risk between the developer and the customer embedded in a precedent agreement is also considered.

Contract Renewal Rights: The flexibility of the renewal provisions of the contract will be assessed as more options provide the LDC with additional tools to manage change.

Demand Charge Mitigation: The ability of Northern to mitigate demand charges by re-selling the pipeline capacity is another qualitative consideration. For example, pipeline capacity that has access to various markets and counterparties can be expected to provide value when the capacity is not utilized at 100% load factor.

Numerous other factors may be evaluated depending on relevance to a given resource or resource need, such as locational needs for system pressure, opportunities to add customers in new areas, operational characteristics and so on.

3. Decision-Making Process

Building on the tools discussed above, Part C below discusses the largely quantitative process Northern uses to identify Incremental Resource Needs and develop Proxy Resources. Northern then seeks and evaluates resources that might meet the identified need. Once reasonably available projects are identified, they are compared in terms of impact on: (i) total portfolio cost impact; and (ii) other resources in the portfolio. In summary, the approaches demonstrated in Part C provide a thorough assessment of the adequacy of the long-term portfolio and a framework to compare alternative resources on an equal footing.

Ultimately, Northern bases proposed resource decisions primarily on qualitative criteria. Thus, resource decisions are informed by quantitative analyses (such as Modeled Cost Analysis output) but are not driven by the results of such analyses. As mentioned, this approach recognizes that many operational characteristics and selection criteria such as added diversity or project risk cannot be adequately modeled. Northern's decision-making approach recognizes that price forecasts are subject to change in unpredictable ways and therefore reduces the possibility that major resource decisions are based primarily on price forecasts.

Lastly, Northern also considers the regulatory environment within which it operates (at the state level) when making resource decisions, as discussed in Part D. The evaluation framework developed by Northern provides a comprehensive and robust comparison of resource alternatives intended to inform Northern with its decision making, but also to demonstrate to state regulators that Northern's decisions are reasonable.

C. Sendout® Modeling

The first steps in long-term planning are to assess the adequacy of the existing portfolio and identify whether an incremental resource need exists. If a need exists, the characteristics of the need must also be assessed. The adequacy of the long-term portfolio is assessed by comparing supply available from existing resources to the Long-Term Planning Load forecast. Northern presented its Resource Balance analysis in Section VII. The Resource Balance showed that on an annual basis, Northern appeared to have adequate resources, but the design day Resource Balance showed that Northern is projected to have a resource deficiency of approximately 32,000 Dth in 2015/16.

1. Identify Incremental Resource Need

In order to more closely evaluate incremental resource need, Northern modeled its existing long-term portfolio using Sendout® with an added resource modeled to dispatch after the existing resources. In this way, Northern was able to analyze the difference between supply available from the current portfolio and Long-Term Planning Load requirements on a daily basis. In developing the analysis, Northern structured the daily distribution of planning load on the basis of historically observed weather patterns to include a design day, a 10-day Cold Snap, design winter and normal summer.[155] Thus, a single model run tests for resource need against design day, design year and cold snap criteria.

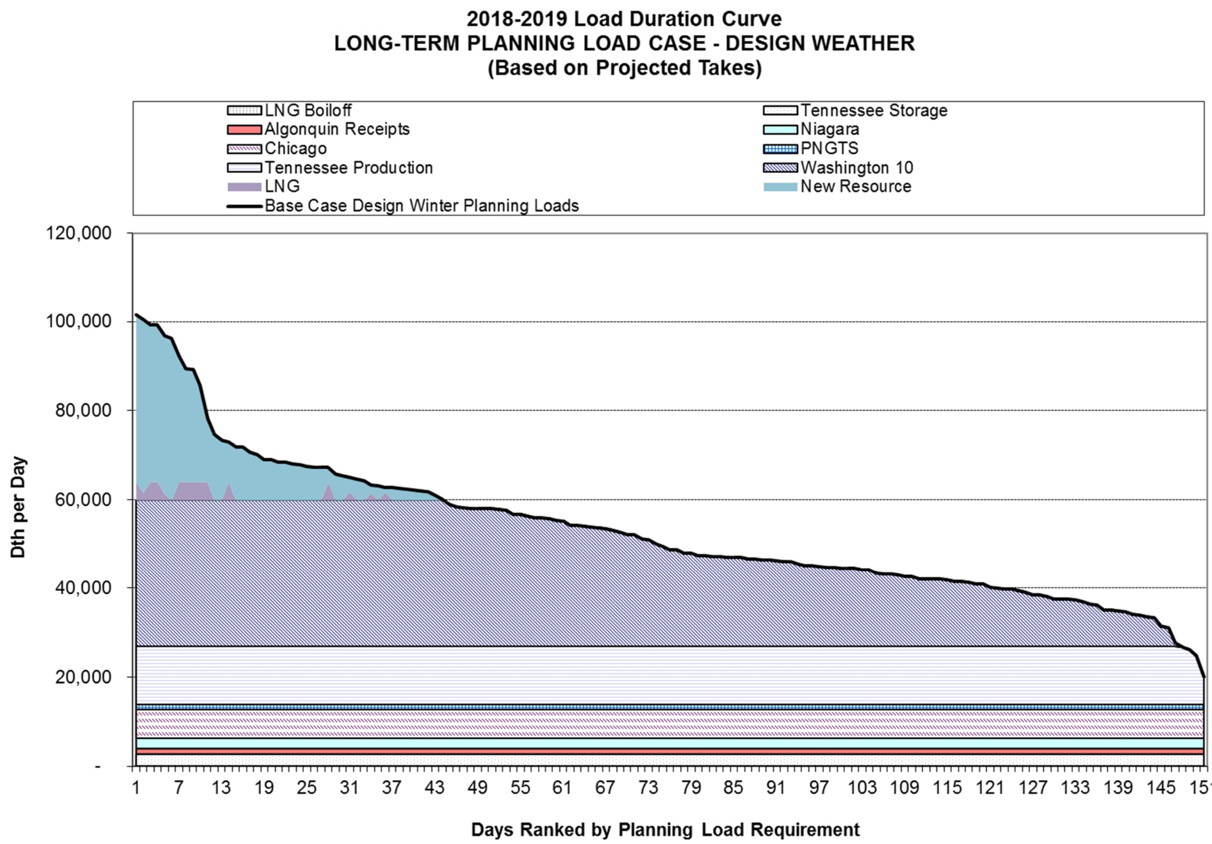
Using the results of the modeling described above, Northern prepared seasonal load duration curves for the five years of the planning period. Seasonal load duration curves were prepared because of the seasonal changes in Northern's portfolio. Most notably, natural gas from the Washington 10 storage facility is only available during the five winter months.

Figure IX-1 provides the design winter load duration curve for 2018/19. Winter and summer load duration curves for the five year planning period are provided in Appendix 5, Supplemental Materials for the Preferred Portfolio Section. In the load duration curve, the incremental resource need is defined by the light blue colored area labeled "New Resource".

Load duration curves provide an informative depiction of resource need. Based upon visual inspection of the load duration curve, the existing portfolio would be unable to meet design planning load requirements for the coldest 45 days of the winter period. Without conducting any further quantitative analysis, the area for New Resource indicates a significant peaking need and additional need that could be met with either storage or pipeline capacity. In the recent years, Northern has met the comparable resource need with short-term resources delivered to its system by others.

[155] Northern defines a Design Year as a design winter plus a normal summer.

Figure IX-1: Load Duration Curve, Design Winter 2018/19

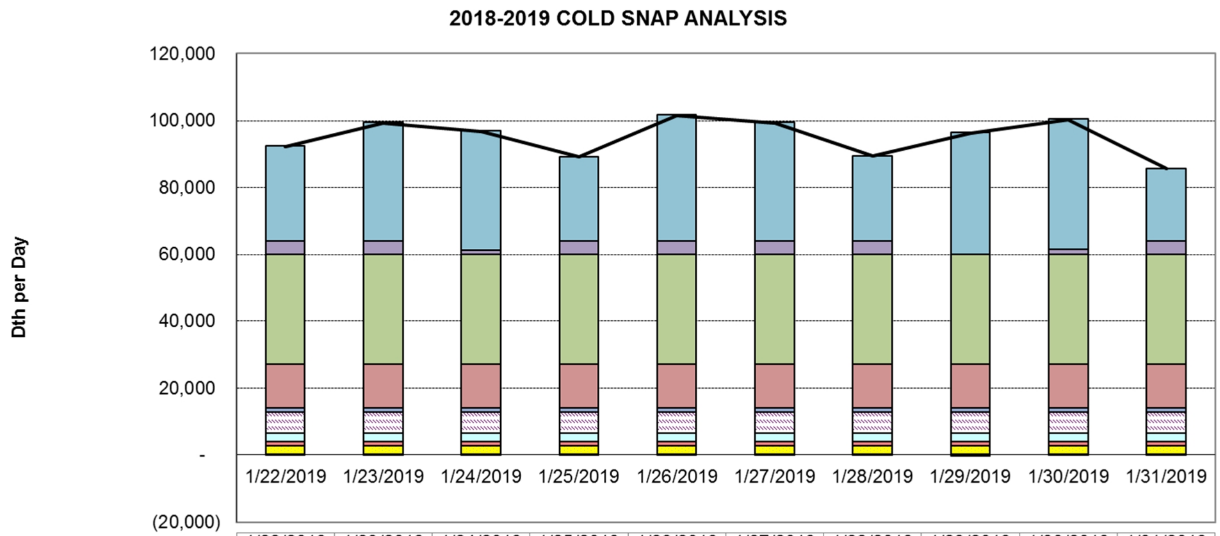


2. Cold Snap Analysis

As mentioned, the cold snap analysis is embedded in the design year Sendout® modeling used to identify the incremental resource need. The Company applied the 10 coldest days on record in its weather databases, which consists of a 44 year history dating back to gas year 1970/71. Specifically, the coldest period observed was the 10 day period that ended on 2/18/1979. During this cold snap, 721 EDD were recorded.

Figure IX-2 demonstrates the operation of the portfolio and the degree of incremental resource need that is required during the modeled cold snap for 2018/19. The chart also lists each supply modeled including the New Resource. Appendix 5 provides the cold snap analyses for the five years of the planning period.

Figure IX-2: Cold Snap Analysis, Design Winter 2018/19



	1/22/2019	1/23/2019	1/24/2019	1/25/2019	1/26/2019	1/27/2019	1/28/2019	1/29/2019	1/30/2019	1/31/2019
New Resource	28,316	35,362	35,604	25,227	37,595	35,362	25,425	36,484	38,861	21,728
LNG	4,111	4,111	1,388	4,111	4,111	4,111	4,111	(0)	1,679	4,111
Washington 10	32,885	32,884	32,884	32,885	32,884	32,884	32,885	32,884	32,885	32,884
Tennessee Production	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
PNGTS	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096
Chicago	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448
Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
Algonquin Receipts	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	70	70	70	70	70	70	70	70	70	70
Cold Snap Loads	92,255	99,302	96,821	89,166	101,535	99,302	89,365	96,312	100,369	85,668

3. Identify Proxy Resources

Results of the Incremental Resource Need Assessment are used to define "Proxy Resources". As mentioned, upon visual inspection one could conclude that the resource need could be met with peaking supply and some combination of storage or pipeline capacity. In this step, Northern would select hypothetical new "Proxy Resources" and add them to the Sendout® model. Unlike the New Resource, which was modeled at a very high price in order to identify the absolute resource need, Proxy Resources are defined by type of resource, quantity and representative pricing. After adding a Proxy Resource to the portfolio model, the resulting load duration curve and impacts on total portfolio cost can be observed. The utilization rate of the Proxy Resource can also be determined as well as the utilization of existing portfolio resources. Through this process, different types of alternative resources, at different quantities can be assessed to determine the types of resources to pursue.

The next step would be to seek resources from developers that closely match the Proxy Resources determined to be favorable candidates for addition to the portfolio.

4. Modeled Cost Analysis

Once actual resources that match the forecasted requirement are identified, they are modeled in Sendout®. Sendout® model results at this stage are used to assess the cost/value of actual projects and to compare competing projects. The primary output for decision-making purposes is impact on total delivered portfolio cost, utilization rates of the proposed resource and impact on utilization rates of existing resources. As discussed earlier, the standard applied to modeled cost results is whether or not competing projects are evaluated to be comparably similar in cost.

5. Flexibility Inherent in Preferred Portfolio

Although Northern does not define a specific Preferred Portfolio that fully meets its Long-Term Planning Load forecast, the following comments on portfolio flexibility are provided. First, acquiring new resources to avoid exposure to delivered supply requires long-term (15+ years) commitments to either new pipeline projects or investment in the construction of new on-system facilities. Such long-term commitments do not allow for early termination (under acceptable terms). Although the commitment for such new resources is fixed and usually not flexible, the resource itself will likely contribute to the overall flexibility of the Northern supply portfolio. Specifically, the resource may have hourly sendout flexibility (e.g., on-system LNG); or the resource may access a new supply basin providing the Company with increased dispatch flexibility. In addition, the new resource may augment or enhance another resource already in the portfolio.

Committing to new long-term resources in a measured way, so as to avoid over committing, is one way to preserve a degree of flexibility. For example, Northern defines its Long-Term Planning Load forecast in a manner that reflects only the demand of sales customers and transportation customers known to be subject to capacity assignment. Under current capacity assignment rules, significantly over contracting could encourage new customers to seek capacity exempt status, which over time would increase the percentage of throughput into the Company's system not supported by long-term resource planning and burden those customers who financially support the portfolio. Northern's balanced and rigorous approach to defining incremental resource need and evaluating quantitative and qualitative aspects of potential incremental resources helps to ensure that new commitments are reasonably sized and complementary to the portfolio.

Another aspect of portfolio flexibility is staggering renewal dates for different paths. However, as discussed earlier turning back long term capacity would likely be an irreversible decision as regaining access to the capacity is unlikely. Capacity can also be used at higher or lower utilization rates and excess capacity can be released in the market or assigned to an asset manager to provide value from capacity that is not needed every day.

D. Regulatory Considerations

Northern enters into transportation, storage and supply contracts on behalf of customers to provide reliable service at a reasonable cost. Northern expends extensive effort to assess the soundness of its decision making and by extension provide supporting data and analysis that is adequate to allow decision makers in both states to approve the cost consequences of any proposed contractual commitment.

Northern serves customers in both Maine and New Hampshire and therefore is regulated by both the Maine Public Utilities Commission and the New Hampshire Public Utilities Commission. As part of any new long-term contract decision, Northern may need guidance from the respective commissions on issues that may impact the decision making process such as the definition of Planning Load or the methodology for assigning capacity to eligible transportation customers.

Lastly, Northern must ensure that new long-term resource decisions are determined by its regulators to promote the public interest, that Northern is granted approval to recover the costs associated with new long-term contracts and that the its regulators will support Northern in the performance of its contractual obligations under new contracts.

X. Compliance with Directives

The following table lists the requirements that are included in Northern's 2011 Long-Range Integrated Resource Plan Stipulation and Settlement Agreement ("2011 IRP Settlement"), approved by the Maine Public Utilities Commission on February 3, 2014 in Docket No. 2011-526 and approved by the New Hampshire Public Utilities Commission on March 26, 2014 in Docket No. DG 11-290.

	Settlement Agreement Terms (Reference)	Northern IRP Compliance
1	**Planning Period** ➢ The IRP shall cover a planning period that includes the next five complete Gas Years after the filing date of the IRP, where a "Gas Year" is the twelve months from November through the following October. ➢ Further, if Northern identifies a resource option that has a term in excess of the planning period, the economic evaluation of that resource must extend to the full term of the resource. (Section II.B.5)	**Planning Period** ➢ The IRP covers the five year planning period of November 2015 through October 2020, which encompasses the next five complete Gas Years. ➢ The longest proposed term for an identified resource is twenty years, with service anticipated to commence four years into the planning horizon (November 2018). In order that an evaluation of the full term of the resource could be conducted, Northern extended its forecast to cover the twenty-five year period ending October 2040.
2	**Demand Forecasts** ➢ Northern shall submit separate base case design day demand and annual demand forecasts for its firm sales and transportation-only customers. ➢ As a comparative reference, Northern shall provide the historical actual peak day sendout, noting the actual 24-hour effective degree day total and the date of the occurrence. ➢ The annual demand forecast will be developed using both normal and design weather conditions. ➢ The demand forecasts will include Northern's projected growth numbers. ➢ Northern will identify and explain any notable deviations from historical growth trends reflected in its demand forecasts. Northern will discuss the predictive ability of its demand forecast models. (Attachment A, Section A.1)	**Demand Forecasts** ➢ Design day and design year throughput forecasts are provided in Section IV.F and Section IV.E, respectively. Additionally, design day and design year throughput are reported for sales service and transportation service customers in Appendix 2. ➢ Section IV.F provides Northern's historical actual peak day throughput, including the effective degree-days recorded and the date of occurrence. ➢ Section IV.D and Section IV.E provide Northern's annual demand forecast under normal and design weather conditions, respectively. ➢ The demand forecasts provided in Section IV include Northern's projected growth numbers. ➢ In Section IV, Northern identifies and explains notable deviations from historical trends reflected in its forecasts and discusses the predictive ability of its demand forecast models.
3	**Planning Standards** ➢ Northern's design day and design year planning standards shall be based on statistical analyses of an updated set of weather data. ➢ In addition to determining the adequacy of its	**Planning Standards** ➢ Northern's design day and design year planning standards are based on statistical analyses of updated weather databases, as discussed in Section IV.E and Section IV.F.

	Settlement Agreement Terms (Reference)	Northern IRP Compliance
	resource portfolio under design day and design year weather conditions, Northern shall evaluate the capability of its resource portfolio to meet sendout requirements during a protracted period of very cold weather (i.e., conduct a cold snap analysis). (Attachment A, Section A.2)	➢ A Cold Snap analysis was conducted as part of the Incremental Resource Need assessment provided in Section IX.C.2; see also Appendix 5 for graphical and tabular output.
4	**Current Portfolio** ➢ Northern shall describe the existing resources that comprise its current portfolio. Resource descriptions will be organized by path and will identify each pipeline segment in each path, from the supply source to destination. ➢ Resource path narratives will describe Northern's current strategies, including information on supply source (market region, liquid or illiquid price point, etc.), whether or not the resource is primarily used as a base load supply, for daily balancing or as peaking supply, and Northern's current method of assigning the resource to delivery service customers subject to capacity assignment as a company managed resource or a capacity release. (Attachment A, Section A.3)	**Current Portfolio** ➢ In Section VI, Northern describes the resources that comprise its current long-term resource portfolio, with resource descriptions organized by path, identifying each pipeline segment from the supply source to the destination. ➢ The resource path narratives in Section VI describe Northern's current resource utilization strategies, discuss supply source characteristics and review the current method of assigning each resource to transportation service customers under the Delivery Service Tariffs in each Division.
5	**Resource Balance** ➢ Northern shall provide information showing the difference between projected design day demand and the peak-day resource capacity of existing resources during the planning period, known as the "Resource Balance." ➢ Northern shall provide information showing the difference between projected annual demand based on both normal and design weather conditions and annual supply capability based on existing contracts during the planning period. ➢ Resource Balance information will be provided in both tabular and graphical form with all resources organized by resource path, consistent with the resource descriptions described in Section A.3. (Attachment A, Section A.4)	**Resource Balance** ➢ Section VII shows the difference between projected design day long-term planning load and the peak-day capacity of Northern's existing long-term resources, or the "Resource Balance." ➢ Section VII also shows the normal and design year "Resource Balance." ➢ The Resource Balance information is provided in both tabular and graphical form. The daily and annual capacity of existing resources is provided by resource with resources organized by path as presented in Section VI, Current Portfolio.
6	**Incremental Supply Resources** ➢ Northern shall identify reasonably available supply resource options that are capable of meeting any portfolio shortfall identified in the projected	**Incremental Supply Resources** ➢ In Section VIII, Northern review pending renewals of existing contracts and also identifies several proposed pipeline projects as well as the possible

	Settlement Agreement Terms (Reference)	Northern IRP Compliance
	resource balance over the planning period, including the renewal of existing contracts scheduled to expire during the planning period. ➢ Northern will describe incremental supply resources in a manner similar to the descriptions of existing resources provided in the Current Portfolio and Resource Balance section. ➢ Resource path narratives will describe Northern's expectations, including information on supply source (market region, liquid or illiquid price point, etc.), whether or not the resource would be primarily used as a base load supply, for daily balancing or as peaking supply, and Northern's expected method of assigning the resource to delivery service customers subject to capacity assignment as a company managed resource or a capacity release. (Attachment A, Section A.5)	construction of a new LNG vaporization and storage facility, all of which would contribute to meeting the identified portfolio shortfall. ➢ Northern describes the incremental supply resource options based largely upon information provided by the project sponsors, including information that was not provided in the Current Portfolio and Resource Balance sections, such as project maps. ➢ Northern generally discusses the likely use of new resources and the expected form of capacity assignment. The project descriptions provide significant detail regarding supply sources that could be accessed.
7	**Preferred Portfolio** ➢ Northern will identify the combination of existing and incremental resources that meets forecasted loads over the planning period (on a design day and design year basis) at the lowest reasonable cost, known as the "Preferred Portfolio." ➢ The methods that Northern uses to evaluate available resource options shall be described in full in the IRP along with the conclusions drawn. ➢ The description of the preferred portfolio will include a discussion of the key factors that led to the conclusion that renewal of existing contracts is economic (or uneconomic) and that certain new resource options are more cost-effective than others, including any workpapers comparing the preferred portfolio to other strategies. ➢ The preferred portfolio will be provided in both tabular and graphical form. ➢ Northern shall discuss the flexibility inherent in its resource planning process, including its approach to acquiring additional resources or releasing contracted resources in the event that actual customer demand is greater than or less than projected needs in the short or long term, and the implications for lowest cost resource.	**Preferred Portfolio** ➢ As indicated in Section IX, Preferred Portfolio, Northern intends to renew its existing long-term resources. Due to ongoing negotiations with multiple parties, the IRP does not select and present specific additional resources for inclusion in the portfolio. ➢ Section IX.B reviews the framework and tools of Northern's resource evaluation process. Project specific conclusions are not provided. ➢ Key factors regarding Northern's intention to renew existing capacity are provided in Section VIII.A. In addition, Section IX.C and Appendix 5 provide load duration curves demonstrating the Incremental Resource Need. ➢ Flexibility inherent in Northern's resource planning process is discussed in Section IX.C.5.

	Settlement Agreement Terms (Reference)	Northern IRP Compliance
	(Attachment A, Section A.6)	
8	**Demand Forecasting Methodology** ***Demand Forecasts*** ➢ The demand forecast that Northern prepares for the IRP shall consist of separate design day and annual demand forecasts for the Maine and New Hampshire Divisions, and a total Northern demand forecast (the sum of the Maine and New Hampshire Divisions' combined forecast results). (Attachment B)	**Demand Forecasting Methodology** ***Demand Forecasts*** ➢ Please see Section IV for Northern's demand forecast. Northern's demand forecast consists of separate design day and annual demand forecasts for the Maine and New Hampshire Divisions, as well as a total Company demand forecast (the sum of the Maine and New Hampshire Division forecast results).
9	**Demand Forecasting Methodology** ***Customer Segments*** ➢ The separate annual demand forecasts for the Maine and New Hampshire Divisions shall be derived from a statistical analysis of data relating to distinguishable customer segments, such as: Residential Non-Heating ("RNH"); Residential Heating ("RH"); Commercial and Industrial Low Load Factor ("C&I LLF); and Commercial and Industrial High Load Factor ("C&I HLF") (collectively, "Customer Segments"). ➢ The demand forecast for each customer segment will be derived from separate forecasts of number of customers and use per customer using a standard commercially available regression analysis package. ➢ Northern's forecasts should segregate unbundled transportation customer volumes from bundled sales service volumes. ➢ The unbundled transportation data should be further segregated into capacity assigned and capacity exempt categories for each division. (Attachment B)	**Demand Forecasting Methodology** ***Customer Segments*** ➢ As discussed in Section IV.C, the demand forecast for each division was developed using statistical analysis of demand by distinguishable Customer Segments. Customer Segments models were developed for Residential Heating, Residential Non-Heating, C&I Low Load Factor and C&I High Load Factor customers. ➢ As discussed in Section IV.C, the customer segment demand forecasts were developed from separate forecasts of number of customers and use per customer using the EViews statistical software package. ➢ Northern developed separate forecasts of sales customer demand and transportation customer demand, as discussed in Section IV.C. ➢ Northern estimated a model that projects capacity exempt demand as a percentage of transportation demand in order to separately show capacity assigned demand and capacity exempt demand under static assumptions.
10	**Demand Forecasting Methodology** ***Data Description and Assessment of Reasonableness*** ➢ The forecast model data will be obtained from Northern's historical records and/or from commercial vendors. ➢ To allow the Parties to assess the reasonableness of Northern's demand forecasts, the IRP will include detailed information on the processes	**Demand Forecasting Methodology** ***Data Description and Assessment of Reasonableness*** ➢ Section IV.C describes the data used to develop the demand forecasts, which included data from Northern's historical billing records and from HIS Global Insight. ➢ (1) Section IV.C and the "Statistical Techniques and

	Settlement Agreement Terms (Reference)	Northern IRP Compliance
	used to develop the demand forecasts including: (1) a detailed description of the process used and the statistic output provided; (2) a list of all variables that were tested in developing each forecast model; (3) statistical output that demonstrates the "goodness of fit" of the final forecast models; and (4) a discussion of the reasonableness of Northern's forecast including the reasonableness of assumptions relating to expected changes in use per customer and changes in regional and national economic growth over the planning period. (Attachment B)	Glossary" section of Appendix 1 detail the process used to develop and test statistical models; (2) all variables tested are listed in Section IV.C and all variables used in each final model are listed along with the statistical output; (3) the statistical output of the final models, statistical tests and residual plots, which collectively demonstrate "goodness of fit" are provided in Appendix 1; and (4) the reasonableness of results are discussed for each model along with demand growth trends and major drivers.
11	**Demand Forecasting Methodology** ***Adjustments to Forecast*** ➢ Natural gas demand for company use will be added to the demand forecast based on historical data, with adjustments to reflect known or expected changes in company use. ➢ Since the customer segment forecasts will be based on metered demand at customer premises, while total Northern system sendout requirement is measured at pipeline city gates and at on-site peak shaving facilities, the demand forecast will be grossed-up for lost and unaccounted for gas volumes in order to project total system sendout requirements. ➢ The demand forecast may also include other load adjustments that, for reasons to be explained by Northern, the normal forecast methodology does not capture. The demand forecast will be reduced by the amount of incremental energy savings known to Northern from approved DSM programs expected to be in operation during the planning period. ➢ Finally, Northern will provide a description of and supporting schedules that reconcile the billing month demand forecast to the calendar month demand forecast (Attachment B)	**Demand Forecasting Methodology** ***Adjustments to Forecast*** ➢ The Company Use forecasts are described in Section IV.D. Company Use is added to customer segment demand as one of the adjustments needed to derive throughput. ➢ Losses and unbilled sales are discussed in Section IV.D. Losses and unbilled sales are added to customer segment demand as an adjustment to derive throughput. ➢ As explained in Section IV.B and demonstrated in Section IV.C, the demand forecast was reduced for expected incremental energy savings from energy efficiency programs, and does not include any other out of model adjustments such as for marketing efforts. ➢ The demand forecasts were modeled using billing cycle monthly data. Historical daily EDD were compiled to facilitate such modeling as described in the "Calculation of Billing Cycle EDD Variable" section of Appendix 1. The billing cycle demand forecast results were converted to calendar month results by applying the losses and unbilled factors that reconcile billing cycle data to calendar month city gate receipt data as explained in Section IV.D.
12	**Demand Forecasting Methodology** ***Demand Forecast Expectations***	**Demand Forecasting Methodology** ***Demand Forecast Expectations***

	Settlement Agreement Terms (Reference)	Northern IRP Compliance
	➢ The use per customer components of the annual demand forecast will contain weather variables to which normal expected weather data will be applied to determine the normal weather forecast. Design weather data will be applied to determine the design weather forecast. ➢ The design day demand forecast models will be estimated using total system level data (not distinguishable by customer segments). The design day demand forecasts will be based on design daily weather conditions, calculated using Northern's most recent 30 year historical weather data. ➢ The forecast shall be a rigorous analysis based on sound application of statistical and economic principles and approaches that is described in detail in the filing (Attachment B)	➢ The use per customer models of the demand forecast all contain weather (Billing Cycle EDD) as an independent variable. Normal expected weather data was used to generate the normal condition forecast and design weather data was used to determine the design condition forecast. ➢ The design day demand forecast models were estimated using total system level data, based on design day weather conditions, calculated using Northern's most recent 30 year historical weather data. See Section IV.F. ➢ The forecast is a rigorous analysis based on sound statistical practices and is well documented in the filing to facilitate review.

OUTLINE OF APPENDIX 1

Supplemental Materials for the Demand Forecast Section

Summary of Demand Forecasting Framework

	Customer Segment Forecast	**Daily Throughput Model**
Purpose	Forecast demand for gas on a monthly basis for the Split Years 2015/16 – 2019/20 based on projected economic and demographic conditions	Forecast demand for gas under design day conditions based on historical daily weather and demand patterns
Periodicity	Monthly	Daily
Units of Time	Billing cycle month	Gas day (10:00 am to 10:00 am)
Historical Time Period	January 2009 – March 2014	November 1, 2012 – March 31, 2014
Independent Variables Types	Economic, demographic, and weather data, indicator variables	Weather and date/seasonal-related data
Demand Data Detail	Six Customer Segments, Special Contracts, plus Company Use	Design Day Throughput
Demand Data Source	Company billing data	Gate station meter reads
Determination of Forecast Demand	Results from (1) number of customers model times (2) use per customer model equals demand	Initial Design Day Throughput Model, escalated at growth in Design Year Throughput
Forecast Period	2015/16 – 19/20 Split Years	2015/16 – 2019/20 Design Days

Calculation of Billing Cycle EDD Variable

Because demand for natural gas is generally affected by weather, including both temperature and wind speed, use per customer models should include a weather variable that (a) reflects temperature and wind speed and (b) measures weather in a manner that reflects the way that the customer class gas usage data is measured and recorded.

It is common operating practice for gas distribution companies, including Northern, to measure and record gas usage data in "billing months". For that purpose, customers are divided into multiple groups, or billing cycles[1], and each group of billing cycle customers is processed through the Company's billing procedures in succeeding business days throughout the month. Distribution companies set the billing cycle schedules to accommodate weekends and holidays, so as a result meters of customers in a billing cycle are read at approximately the same time of the month, every month.

As a result of this billing process, most of the gas consumption between meter readings of customers in an early billing cycle (e.g., Cycles 1 or 2) occurs in the prior calendar month; in contrast, most of the gas consumption between meter readings of customers in a later billing cycle (e.g., Cycles 19 or 20) occurs in the current calendar month. "Billing Month deliveries" are the gas deliveries as measured by customer meter readings and recorded by billing month (which includes consumption in the prior and current calendar month), and "Calendar Month deliveries" are estimated gas deliveries by calendar month.

For Northern's 2015 IRP Customer Segment models, the Company converted monthly EDDs to a billing month basis to be consistent with the Customer Segment data. Billing month EDD data was derived from daily EDD data by (1) summing the days of consumption that impact metered deliveries in the billing month and (2) developing weighting factors, i.e., Billing Month Percent Factors ("Percent Factors"), based on those sums that relate billing cycle data to calendar consumption. The weighting distribution allocates calendar EDD over the course of the month. The Percent Factors for the first and last days in the billing month are relatively small; Percent Factors for days in the middle of the billing month are the largest. Below is an example of the Percent Factors used to convert weather data from a calendar month basis to a billing month basis for the January billing month:

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[1] Dividing the customers into billing cycles allows for the most efficient use of meter reading and billing systems.

																																		Percent Factors		
	Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	Days	DEC	JAN	FEB
Prior Month (December)	1	1																															1	97%	3%	
	2	1	1																														2	94%	6%	
	3	1	1	1																													3	90%	10%	
	4	1	1	1	1																												4	87%	13%	
	5	1	1	1	1	1																											5	84%	16%	
	6	1	1	1	1	1	1																										6	81%	19%	
	7	1	1	1	1	1	1	1																									7	77%	23%	
	8	1	1	1	1	1	1	1	1																								8	74%	26%	
	9	1	1	1	1	1	1	1	1	1																							9	71%	29%	
	10	1	1	1	1	1	1	1	1	1	1																						10	68%	32%	
	11	1	1	1	1	1	1	1	1	1	1	1																					11	65%	35%	
	12	1	1	1	1	1	1	1	1	1	1	1	1																				12	61%	39%	
	13	1	1	1	1	1	1	1	1	1	1	1	1	1																			13	58%	42%	
	14	1	1	1	1	1	1	1	1	1	1	1	1	1	1																		14	55%	45%	
	15	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1																	15	52%	48%	
	16	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1																16	48%	52%	
	17	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1															17	45%	55%	
	18	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1														18	42%	58%	
	19	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1													19	39%	61%	
	20	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1												20	35%	65%	
	21	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1											21	32%	68%	
	22	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1										22	29%	71%	
	23	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1									23	26%	74%	
	24	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1								24	23%	77%	
	25	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1							25	19%	81%	
	26	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1						26	16%	84%	
	27	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					27	13%	87%	
	28	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1				28	10%	90%	
	29	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			29	6%	94%	
	30	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		30	3%	97%	
	31	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	31	0%	100%	
Billing Month (January)	1	R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	30		97%	3%
	2		R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	29		94%	6%
	3			R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	28		90%	10%
	4				R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	27		87%	13%
	5					R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	26		84%	16%
	6						R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	25		81%	19%
	7							R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	24		77%	23%
	8								R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	23		74%	26%
	9									R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	22		71%	29%
	10										R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	21		68%	32%
	11											R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	20		65%	35%
	12												R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	19		61%	39%
	13													R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	18		58%	42%
	14														R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	17		55%	45%
	15															R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	16		52%	48%
	16																R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	15		48%	52%
	17																	R	1	1	1	1	1	1	1	1	1	1	1	1	1	1	14		45%	55%
	18																		R	1	1	1	1	1	1	1	1	1	1	1	1	1	13		42%	58%
	19																			R	1	1	1	1	1	1	1	1	1	1	1	1	12		39%	61%
	20																				R	1	1	1	1	1	1	1	1	1	1	1	11		35%	65%
	21																					R	1	1	1	1	1	1	1	1	1	1	10		32%	68%
	22																						R	1	1	1	1	1	1	1	1	1	9		29%	71%
	23																							R	1	1	1	1	1	1	1	1	8		26%	74%
	24																								R	1	1	1	1	1	1	1	7		23%	77%
	25																									R	1	1	1	1	1	1	6		19%	81%
	26																										R	1	1	1	1	1	5		16%	84%
	27																											R	1	1	1	1	4		13%	87%
	28																												R	1	1	1	3		10%	90%
	29																													R	1	1	2		6%	94%
	30																														R	1	1		3%	97%
	31																															R	0		0%	100%

A string of Percent Factors was calculated for each of the 12 billing months in a year. For each day in the billing month, the actual daily EDD was multiplied by the corresponding Percent Factor for that day to determine the billing month EDDs.

Calculation of Natural Gas Prices

Because economic theory suggests that demand is likely to be influenced by price, a natural gas price variable that reflects the price that Northern Utilities' customers pay for gas service was developed to be tested in the use per customer models.

Historical natural gas prices were developed for each Maine Division and New Hampshire Division Customer Segment models by dividing the monthly Customer Segment sales revenues by Customer Segment sales demand (dekatherms); the calculated values represent the full delivered cost to customers of gas service "at the burner-tip." Because the full cost of gas service to Transportation Service customers is unknown to Northern, the delivered price to Sales Service customers was used as a proxy for the full cost of service to both sales and transportation customers.[1] All nominal historical prices were converted to real dollars on a monthly basis for each Division using the Consumer Price Index ("CPI) for Maine and New Hampshire, provided by Global Insight, Inc.

To develop forecasted natural gas prices for each Customer Segment that are calibrated to Northern's service territory, percent changes in the Global Insight forecasted natural gas delivery prices to Maine and New Hampshire customers by month from March 2013 through October 2020 were applied to the rolling 12 month average of historical Northern natural gas prices by Division. Global Insight provided forecasted monthly delivered natural gas prices in Maine and New Hampshire for three customer sectors: (1) residential, (2) commercial, and (3) industrial. The Global Insight price forecasts by sector were used to forecast prices for each of Northern's sales Customer Segments as follows.

Global Insight Sector	Northern Customer Segment
ME/NH Residential	Residential Heating Residential Non-Heating
ME/NH Commercial	C&I Low Load Factor
ME/NH Industrial	C&I High Load Factor

The use per customer models use natural gas price variables calculated as rolling 12 month averages from the actual and forecasted monthly natural gas price data. The 12 month average price

[1] Thus, the same C&I price variables were used in the C&I Total Customer use per customer models and in the C&I Sales Customer use per customer models.

variable reflects the concept that gas equipment purchases and changes in gas usage behavior are customer decisions that occur over an extended period - twelve months.[2]

[2] A price variable that is calculated as rolling averages also avoids a statistical problem with data known as "simultaneity," which occurs when two variables have an effect on each other at the same time. For example, the price of gas service, measured as average revenues per therm may be generally higher in the summer, and lower in the winter because of the impact of fixed customer charges on the average rate, divided by low delivery quantities in the summer and high delivery quantities in the winter. Simultaneity occurs because in this example, a high price did not cause low usage; rather, a high price was caused by low usage.

Statistical Techniques and Glossary

Regression modeling techniques were used to generate the demand forecasts for both Divisions. The regression analyses were developed in the EViews software package. Regression modeling techniques were used to develop separate Maine and New Hampshire forecasts of (a) number of customers, (b) use per customer for each of six Customer Segment models, as well as demand forecasts for (1) Special Contract customers, (2) Company Use, and (3) Daily Throughput.

Regression Analysis

Econometrics is the empirical determination of economic laws; it involves the application of statistical techniques and analyses to the study of economic data. A fundamental statistical method of econometrics is regression analysis, which is concerned with the study of the relationship between one variable, i.e., the dependent variable, and one or more other variables, i.e., the independent or explanatory variables. One of the primary uses of regression analysis is to forecast the values of the dependent variable, given forecast values of the independent variables.[1]

Northern forecast models of number of customers, use per customer, or demand, regression equations were developed with appropriate variables, such as weather, natural gas prices, economic data, and dummy variables, etc. Each of the forecast models explains historical values of the dependent variable as a function of historical values of the independent variables; the models produce forecasted values of the dependent variable based on forecasted values of the independent variables.

The forecast models for this IRP were developed using the following process: (a) the appropriate economic theory that the model should be based on was considered (b) appropriate data was collected; (c) mathematical and statistical models were specified; (d) the model parameters were estimated; (e) the accuracy of the model was checked; (f) hypotheses about the model and its parameters were tested; and (g) the models were used to prepare the forecast.[2]

First, based on economic theory and standard utility forecasting practice, independent variables were identified that could have an effect on the dependent variable in each equation, and expectations about the appropriate sign of the coefficients for those variables was determined. For example, the EDD variable is expected to affect use per customer, and the relationship would be expected to be positive (i.e., when EDDs increase, demand should increase, and vice versa). The price variable is also expected to

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1 A glossary of statistical terms can be found at the end of this Appendix.

2 This process was derived from Essentials of Econometrics, Damodar Gujarati, p. 3 (1999 Irwin McGraw-Hill).

affect use per customer and the relationship would be expected to be negative (i.e., when natural gas prices increase, demand should decrease, and vice versa).

For each of the models, after the possible explanatory variables were identified and the data sets were developed, potential regression equations were created to test various combinations of independent variables. Based on: (1) the theoretical relevance and signs of the independent variables; (2) the results of various statistical tests that assess the significance of the independent variables included in the equation; and (3) the explanatory power of the equation as a whole, a preliminary regression equation was identified for each model. If the sign of an independent variable was counter to expectations or if important variables were not significant, either, (a) that model not considered further or (b) modified forms of the model with different variables were considered. The statistical significance of each independent variable was determined by examining the variable t-test values; variables that were significant at the 0.10 level were included in a model.[3] Finally, equations were evaluated based on explanatory power, as determined by the R^2. Models that met all of these criteria were subjected to further testing, for example, for autocorrelation and heteroskedasticity.

Autocorrelation

Statistical theory requires that the residuals (the “error terms”) associated with a regression equation be independent of one another (i.e., there should be no relationship or correlation in the residuals over time).[4] Correlation of residuals over time is known as “autocorrelation”. One aspect of time series analysis is to identify and correct for autocorrelation.

Autocorrelation can be present between two consecutive periods (lag 1 or first-order), periods separated by one period (lag 2 or second-order), periods separated by two periods (lag 3 or third-order), etc. The Durbin-Watson statistic is a standard test for first-order autocorrelation; autocorrelation function (“ACF”) and partial autocorrelation function (“PACF”) values and graphs are used to test for higher orders of autocorrelation.[5] Advanced statistical packages such as EViews correct for higher order autocorrelation, based on user inputs.

The forecast models for this IRP were examined for orders of autocorrelation from lag(s) 1 through 24using the ACF and PACF graphs. If autocorrelation was identified, the appropriate autoregressive terms (“AR”) were added to the regression equation to correct for the autocorrelation (e.g.,

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[3] Depending on specific circumstances, acceptable statistical practice allows for including variables that are not statistically significant in a regression model.

[4] In statistical theory, a regression equation with residuals that are independent of one another equation is efficient. The coefficients of an “efficient” regression equation have the smallest (i.e., minimum) variance.

[5] The presence of autocorrelation is indicated by ACF or PACF values that fall beyond two standard errors.

autocorrelation at lag 4 would be corrected by adding an AR4 term to the regression equation). The regression equations were re-evaluated after any necessary corrections for autocorrelation were made. If correcting for autocorrelation in residuals decreased an independent variable's t-statistic to the extent that the variable was no longer significant, the equation parameters were re-estimated with the statistically insignificant variables excluded.

Heteroskedasticity

Statistical theory also requires that the residuals associated with a regression equation have constant variance to ensure that the equation is efficient. Non-constant variance is known as "heteroskedasticity". The forecast models for this IRP were tested for heteroskedasticity using White's Test. The White's Test statistic is developed by regressing the squared residuals from the original regression against the original independent variables, the independent variables squared, and the cross products. The R^2 from this regression is multiplied by the number of observations compared against a χ^2 distribution to test for significance; models with White's Test results that were not significant at the 0.01 level were considered to not exhibit heteroskedasticity.

If the overall explanatory power of the model was significantly reduced after correcting for the various statistical issues described above, another preliminary model was examined. This process continued until a model was developed with appropriate statistical properties and explanatory power. Details associated with final model results, including all parameters, residuals, and the results of all the statistical tests described above can be found in the Appendix.

Glossary of Statistical Terms[6]

Term	**Definition**
Adjusted R^2	A measure of the overall goodness of fit for the regression model, taking into account the number of independent variables in the model. Adjusted R^2 ranges from 0 to 1; the closer the Adjusted R^2 value is to 1, the better the fit of the model. Adjusted R^2 can be interpreted as the amount of variability of the dependent variable that is explained by the regression equation, taking into consideration the number of independent variables in the model.
Autocorrelation	A measure of the correlation of the values of a series with the values lagged by 1 or more cases. (Other equivalent terms include: serial correlation)
Autocorrelation Function ("ACF")	A function defined as the autocorrelation of the residuals at various lags; can be shown as a graph.
Correlation	A measure of the degree of relationship between two variables. The value of a correlation can range from -1 to 1, with values close to +/-1 indicating a strong relationship between two variables and a correlation close to 0 indicating no relationship between the variables.
Dependent Variable	A dependent variable is one that is observed to change in response to the independent variables. (Other equivalent terms include: response variable, result variable, outcome variable, endogenous variable, output variable, Y-variable)
Estimate (of the Independent Variable)	A measure of the value of the model parameter (i.e., independent variable). (Other equivalent terms include: coefficient of the independent variable)
F statistic	A measure of whether a regression equation is significant (i.e., whether the set of independent variables in a model explains a significant portion of the variability of the dependent variable). Calculated as the mean-square regression divided by the mean square residuals. The value of the F statistic ranges from zero to positive infinity, with large positive values indicating that the model is significant.
Forecast	The values predicted by the model for the forecast period.
Independent Variable	A variable used to attempt to explain the behavior of another variable (see Dependent Variable) in a regression equation. (Other equivalent terms include: explanatory variable, exogenous variable, external variable, predictor variable, causal variable, input variable, X-variable, regressors)
Model	A specific set of independent variables and their parameters used to explain a dependent variable. (Other equivalent terms include: Equation)
Number of Observations ("N")	The amount of data used to develop the model (i.e., the number of data points that are included for each variable in the model).
Number of Predictors	The amount of independent variables included in the model. Note that Number of Predictors measures the total number of independent variables included in the model, not only the significant independent variables.

6 These terms are defined as they relate to the econometric/regression analysis used in this IRP.

Term	**Definition**
Partial Autocorrelation Function ("PACF")	A function defined as the partial autocorrelation of the residuals at various lags. Partial autocorrelation is a measure of the correlation of the values of a series with values lagged by one or more cases, after the effects of correlations at the intervening lags have been removed; can be shown as a graph.
R^2	A measure of the overall goodness of fit for the regression model. R^2 ranges from 0 to 1; the closer the R^2 value is to 1, the better the fit of the model. R^2 can be interpreted as the amount of variability of the dependent variable that is explained by the regression equation.
Residual	The difference between the actual historical values of the dependent variable and the values predicted by the model (i.e., the model fits). (Other equivalent terms include: error, error term)
Root Mean Square Error ("RMSE")	A measure of the variability of the residuals. (Other equivalent terms include: Standard Error of the Regression)
Significance of the t statistic	A measure of the strength (or significance level) of the t statistic. A low value of the significance level of the t statistic is desired, as it indicates the related independent variable is significant in the equation. In general, only independent variables that had t statistics that were significant at the 0.10 level (i.e. less than 0.10) were included in the final equation. (Other equivalent terms include: p-value) Although statistical significance is dependent on the number of observations and number of explanatory variables in the equation, generally, t statistics greater than 2.0 are statistically significant.
Standard Error (of the Estimate of the Independent Variable) ("SE")	A measure of how much the value of a test statistic varies (i.e., the standard deviation of the sampling distribution for a statistic), in this case the Estimate of the Independent Variable.
t statistic	A measure of whether the coefficient for an independent variable is statistically different than zero. Calculated as the Estimate of the Independent Variable divided by its Standard Error. The value of t statistic ranges from negative infinity to positive infinity, with values far from zero indicating that the independent variable is significant in the model. (Other equivalent terms include: t-Statistic, t-Test, Student's t)

Maine Division Statistical Model Results

Dependent Variable: M_RH_C
Method: Least Squares
Date: 05/16/14 Time: 12:04
Sample (adjusted): 2009M03 2014M03
Included observations: 61 after adjustments
Convergence achieved after 48 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
POP	75.41488	26.78975	2.815065	0.0072
OCT	205.3934	26.49684	7.751619	0.0000
NOV	319.7700	44.23766	7.228455	0.0000
DEC	385.8996	51.43289	7.502974	0.0000
JAN	408.2988	51.16381	7.980226	0.0000
FEB	389.8506	48.51111	8.036317	0.0000
MAR	355.7438	44.39533	8.013090	0.0000
APR	269.1826	36.00036	7.477219	0.0000
MAY	84.63971	22.29958	3.795574	0.0004
C	-87320.42	35591.53	-2.453404	0.0181
TREND	41.94104	1.020087	41.11516	0.0000
D_2013M7M8	-115.6549	51.21249	-2.258334	0.0288
D_2013M7_	-2599.283	732.0596	-3.550644	0.0009
D_2013M7_*TREND	44.69882	12.58212	3.552567	0.0009
AR(1)	1.068930	0.138456	7.720330	0.0000
AR(2)	-0.476585	0.158784	-3.001474	0.0044

R-squared	0.997621	Mean dependent var	14443.25
Adjusted R-squared	0.996829	S.D. dependent var	789.3201
S.E. of regression	44.45132	Akaike info criterion	10.64705
Sum squared resid	88916.41	Schwarz criterion	11.20072
Log likelihood	-308.7349	Hannan-Quinn criter.	10.86403
F-statistic	1258.238	Durbin-Watson stat	2.023336
Prob(F-statistic)	0.000000		
Inverted AR Roots	.53-.44i	.53+.44i	

Variable Name	Definition
POP	Population
OCT	October
NOV	November
DEC	December
JAN	January
FEB	February
MAR	March
APR	April
MAY	May
C	Constant
TREND	Linear Trend
D_2013M7M8	Dummy, July - August 2013
D_2013M7_	Dummy, July 2013 and forward
D_2013M7_*TREND	Interaction Variable - Linear Trend * Dummy, July 2013 and forward
AR(1)	Autoregressive Term, lag 1
AR(2)	Autoregressive Term, lag 2

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	0.377266	Prob. F(13,47)	0.9707
Obs*R-squared	5.763898	Prob. Chi-Square(13)	0.9543
Scaled explained SS	4.114442	Prob. Chi-Square(13)	0.9899

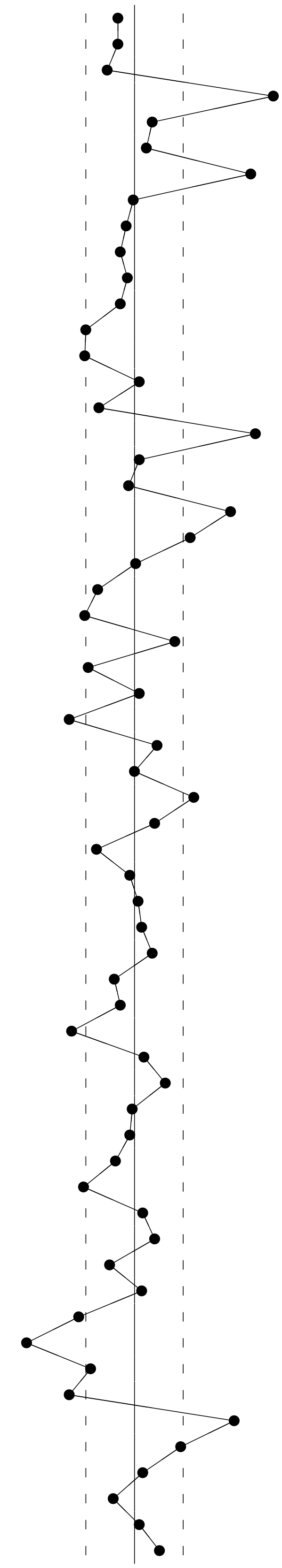
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 11/25/14 Time: 14:50
Sample: 2009M03 2014M03
Included observations: 61

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	115566.8	818339.5	0.141221	0.8883
POP	-85.65058	615.9555	-0.139053	0.8900
OCT	-1315.684	1308.476	-1.005509	0.3198
NOV	-312.8090	1303.772	-0.239926	0.8114
DEC	-1495.445	1307.623	-1.143636	0.2586
JAN	-1071.572	1319.930	-0.811840	0.4210
FEB	-1952.043	1340.517	-1.456187	0.1520
MAR	-1097.274	1264.538	-0.867727	0.3900
APR	-816.8723	1298.742	-0.628972	0.5324
MAY	-439.4566	1298.962	-0.338314	0.7366
TREND	16.84193	24.61000	0.684353	0.4971
D_2013M7M8	1155.445	3090.446	0.373877	0.7102
D_2013M7_	-16308.25	31030.58	-0.525554	0.6017
D_2013M7_*TREND	251.1699	517.5582	0.485298	0.6297

R-squared	0.094490	Mean dependent var	1457.646
Adjusted R-squared	-0.155970	S.D. dependent var	2380.516
S.E. of regression	2559.436	Akaike info criterion	18.73125
Sum squared resid	3.08E+08	Schwarz criterion	19.21571
Log likelihood	-557.3032	Hannan-Quinn criter.	18.92112
F-statistic	0.377266	Durbin-Watson stat	2.389201
Prob(F-statistic)	0.970684		

obs	Actual	Fitted	Residual
2009M04	4926.00	4933.69	-7.68541
2009M05	4900.00	4907.38	-7.37933
2009M06	4867.00	4879.31	-12.3069
2009M07	4912.00	4849.66	62.3374
2009M08	4909.00	4901.03	7.96927
2009M09	4911.00	4905.44	5.56367
2009M10	4970.00	4917.32	52.6757
2009M11	4990.00	4990.54	-0.53639
2009M12	5012.00	5015.60	-3.59814
2010M01	5033.00	5039.51	-6.50799
2010M02	5035.00	5038.08	-3.08412
2010M03	5025.00	5031.52	-6.51828
2010M04	4996.00	5017.95	-21.9530
2010M05	4951.00	4973.42	-22.4222
2010M06	4921.00	4919.00	1.99771
2010M07	4867.00	4883.15	-16.1493
2010M08	4890.00	4835.62	54.3845
2010M09	4882.00	4879.63	2.36507
2010M10	4880.00	4882.54	-2.53914
2010M11	4922.00	4878.66	43.3440
2010M12	4944.00	4918.67	25.3301
2011M01	4944.00	4943.43	0.56796
2011M02	4949.00	4965.65	-16.6520
2011M03	4939.00	4961.43	-22.4340
2011M04	4955.00	4936.91	18.0937
2011M05	4922.00	4942.69	-20.6940
2011M06	4904.00	4901.75	2.25472
2011M07	4854.00	4883.59	-29.5870
2011M08	4843.00	4832.92	10.0829
2011M09	4831.00	4830.93	0.07376
2011M10	4848.00	4821.46	26.5429
2011M11	4850.00	4840.88	9.11765
2011M12	4824.00	4841.32	-17.3159
2012M01	4817.00	4819.38	-2.38109
2012M02	4803.00	4801.63	1.37114
2012M03	4788.00	4785.03	2.96997
2012M04	4776.00	4767.72	8.28178
2012M05	4761.00	4770.12	-9.12271
2012M06	4749.00	4755.56	-6.56287
2012M07	4715.00	4743.58	-28.5776
2012M08	4697.00	4692.78	4.21613
2012M09	4687.00	4673.23	13.7741
2012M10	4664.00	4664.86	-0.85681
2012M11	4650.00	4652.15	-2.15439
2012M12	4632.00	4640.60	-8.60316
2013M01	4596.00	4619.27	-23.2723
2013M02	4580.00	4576.22	3.78395
2013M03	4567.00	4557.96	9.03531
2013M04	4538.00	4549.12	-11.1175
2013M05	4523.00	4519.94	3.05653
2013M06	4482.00	4507.32	-25.3185
2013M07	4365.00	4413.50	-48.5001
2013M08	4317.00	4336.86	-19.8574
2013M09	4288.00	4317.37	-29.3742
2013M10	4291.00	4245.89	45.1087
2013M11	4278.00	4256.87	21.1294
2013M12	4259.00	4255.32	3.67879
2014M01	4247.00	4256.63	-9.63196
2014M02	4245.00	4242.93	2.07238
2014M03	4253.00	4241.58	11.4243

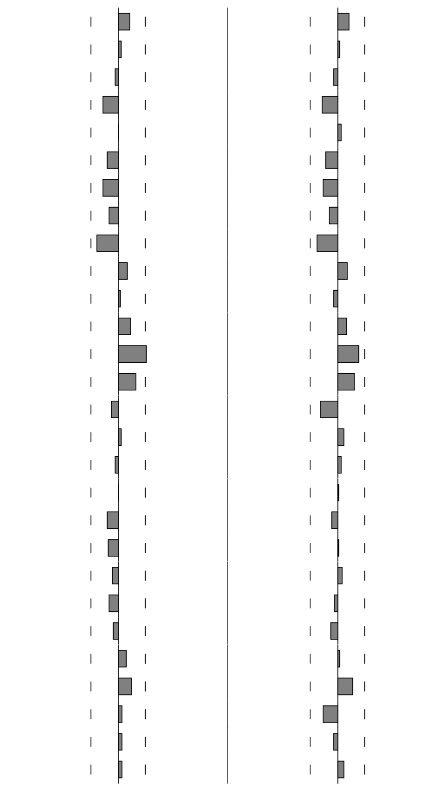
Residual Plot



Correlogram of Residuals

Date: 12/15/14 Time: 12:16
Sample: 2009M04 2014M03
Included observations: 60
Q-statistic probabilities adjusted for 3 ARMA term(s)

Autocorrelation | Partial Correlation



	AC	PAC	Q-Stat	Prob
1	0.109	0.109	0.7441	
2	0.030	0.018	0.8012	
3	-0.030	-0.035	0.8588	
4	-0.146	-0.141	2.2713	0.132
5	0.007	0.040	2.2748	0.321
6	-0.105	-0.107	3.0389	0.386
7	-0.140	-0.131	4.4049	0.354
8	-0.084	-0.075	4.9081	0.427
9	-0.201	-0.192	7.8648	0.248
10	0.088	0.092	8.4394	0.295
11	0.022	-0.035	8.4767	0.388
12	0.119	0.088	9.5786	0.386
13	0.268	0.200	15.260	0.123
14	0.170	0.157	17.597	0.091
15	-0.063	-0.156	17.923	0.118
16	0.027	0.061	17.984	0.158
17	-0.026	0.035	18.043	0.205
18	0.004	0.011	18.045	0.260
19	-0.099	-0.055	18.935	0.272
20	-0.093	0.014	19.741	0.288
21	-0.052	0.045	20.000	0.333
22	-0.086	-0.028	20.719	0.353
23	-0.046	-0.064	20.927	0.401
24	0.080	0.022	21.581	0.424
25	0.127	0.146	23.288	0.386
26	0.036	-0.138	23.433	0.436
27	0.037	-0.037	23.585	0.486
28	0.036	0.063	23.735	0.535

Dependent Variable: M_RH_UPC
Method: Least Squares
Date: 05/16/14 Time: 11:43
Sample (adjusted): 2009M12 2014M03
Included observations: 52 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_BC	0.007255	0.000353	20.56933	0.0000
RH_PRICE	-0.182005	0.120981	-1.504413	0.1396
C	3.284779	1.822037	1.802805	0.0783
EDD_BC*DEC	0.001273	0.000370	3.438881	0.0013
EDD_BC*JAN	0.002577	0.000339	7.601654	0.0000
EDD_BC*FEB	0.002323	0.000338	6.865305	0.0000
EDD_BC*MAR	0.001939	0.000355	5.467936	0.0000
TREND	0.010600	0.005170	2.050268	0.0463

R-squared	0.987745	Mean dependent var	6.456057
Adjusted R-squared	0.985795	S.D. dependent var	4.665619
S.E. of regression	0.556063	Akaike info criterion	1.804769
Sum squared resid	13.60508	Schwarz criterion	2.104961
Log likelihood	-38.92400	Hannan-Quinn criter.	1.919856
F-statistic	506.6253	Durbin-Watson stat	1.905938
Prob(F-statistic)	0.000000		

Variable Name	Definition
EDD_BC	Bill Cycle EDD
RH_PRICE	Residential Natural Gas Price
C	Constant
EDD_BC*DEC	Interaction Variable - Bill Cycle EDD * December
EDD_BC*JAN	Interaction Variable - Bill Cycle EDD * January
EDD_BC*FEB	Interaction Variable - Bill Cycle EDD * February
EDD_BC*MAR	Interaction Variable - Bill Cycle EDD * March
TREND	Linear Trend

Heteroskedasticity Test: Harvey

F-statistic	0.772705	Prob. F(7,44)	0.6132
Obs*R-squared	5.692586	Prob. Chi-Square(7)	0.5761
Scaled explained SS	4.252989	Prob. Chi-Square(7)	0.7502

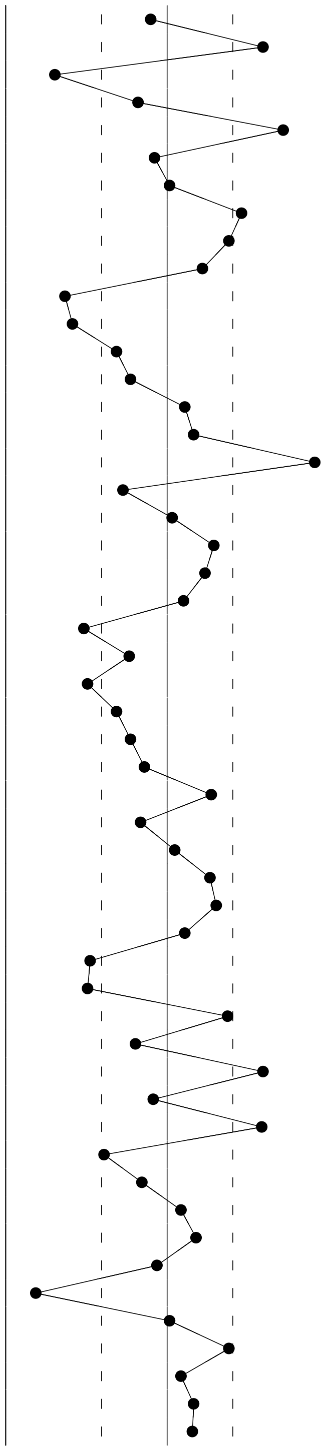
Test Equation:
Dependent Variable: LRESID2
Method: Least Squares
Date: 12/15/14 Time: 12:31
Sample: 2009M12 2014M03
Included observations: 52

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-1.374649	6.454448	-0.212977	0.8323
EDD_BC	0.002046	0.001249	1.637630	0.1086
RH_PRICE	-0.074568	0.428567	-0.173993	0.8627
EDD_BC*DEC	-0.000610	0.001312	-0.464975	0.6442
EDD_BC*JAN	-0.001366	0.001201	-1.137178	0.2616
EDD_BC*FEB	-0.001110	0.001198	-0.926336	0.3593
EDD_BC*MAR	-0.002122	0.001256	-1.689385	0.0982
TREND	-0.018179	0.018314	-0.992633	0.3263

R-squared	0.109473	Mean dependent var	-2.463492
Adjusted R-squared	-0.032202	S.D. dependent var	1.938848
S.E. of regression	1.969818	Akaike info criterion	4.334398
Sum squared resid	170.7281	Schwarz criterion	4.634589
Log likelihood	-104.6943	Hannan-Quinn criter.	4.449484
F-statistic	0.772705	Durbin-Watson stat	2.321189
Prob(F-statistic)	0.613233		

obs	Actual	Fitted	Residual
2009M12	7.70135	7.83605	-0.13470
2010M01	14.0225	13.2110	0.81149
2010M02	11.4590	12.4145	-0.95545
2010M03	8.79853	9.04180	-0.24327
2010M04	6.46423	5.47846	0.98577
2010M05	3.75591	3.86143	-0.10551
2010M06	2.06558	2.04847	0.01711
2010M07	1.64822	1.01232	0.63590
2010M08	1.35955	0.83643	0.52313
2010M09	1.49735	1.19533	0.30202
2010M10	2.11499	2.98064	-0.86565
2010M11	5.01464	5.82165	-0.80702
2010M12	8.97612	9.40053	-0.42442
2011M01	13.2297	13.5364	-0.30675
2011M02	14.4589	14.3101	0.14878
2011M03	11.3965	11.1674	0.22912
2011M04	8.59183	7.34457	1.24726
2011M05	4.25314	4.63100	-0.37786
2011M06	2.67406	2.63467	0.03939
2011M07	1.77928	1.38763	0.39165
2011M08	1.34057	1.02292	0.31765
2011M09	1.55764	1.42058	0.13706
2011M10	1.99337	2.70253	-0.70916
2011M11	5.12971	5.44574	-0.31603
2011M12	7.16811	7.84562	-0.67750
2012M01	12.2154	12.6438	-0.42835
2012M02	11.8648	12.1792	-0.31441
2012M03	9.74465	9.93519	-0.19054
2012M04	6.27582	5.90332	0.37250
2012M05	4.11030	4.33656	-0.22626
2012M06	2.41759	2.35175	0.06584
2012M07	1.58775	1.22717	0.36058
2012M08	1.38857	0.97522	0.41335
2012M09	1.51392	1.36086	0.15306
2012M10	2.45972	3.11362	-0.65390
2012M11	5.27927	5.95207	-0.67280
2012M12	9.75030	9.23618	0.51412
2013M01	12.6300	12.9017	-0.27168
2013M02	14.0547	13.2369	0.81779
2013M03	10.4268	10.5408	-0.11400
2013M04	8.10127	7.30095	0.80032
2013M05	4.22317	4.76226	-0.53909
2013M06	2.43218	2.64657	-0.21439
2013M07	1.47947	1.35914	0.12033
2013M08	1.39242	1.14681	0.24561
2013M09	1.52204	1.60247	-0.08043
2013M10	2.08971	3.20388	-1.11417
2013M11	5.88814	5.87134	0.01680
2013M12	11.2393	10.7162	0.52302
2014M01	15.4493	15.3302	0.11903
2014M02	14.5003	14.2797	0.22062
2014M03	13.2273	13.0133	0.21406

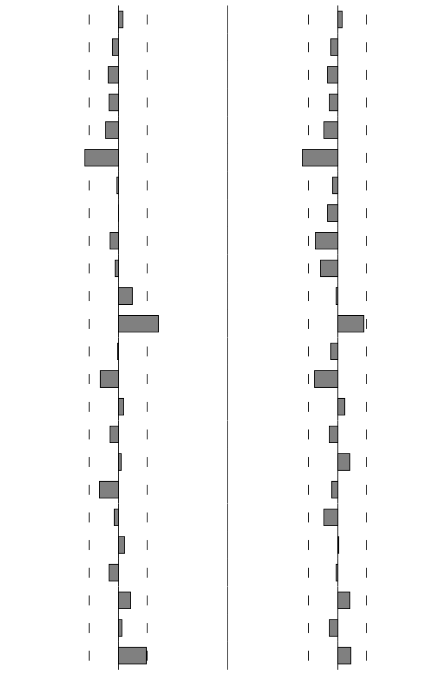
Residual Plot



Correlogram of Residuals

Date: 12/15/14 Time: 12:30
Sample: 2009M12 2014M03
Included observations: 52

Autocorrelation | Partial Correlation



	AC	PAC	Q-Stat	Prob
1	0.045	0.045	0.1099	0.740
2	-0.056	-0.058	0.2864	0.867
3	-0.095	-0.091	0.8090	0.847
4	-0.085	-0.081	1.2268	0.874
5	-0.117	-0.124	2.0480	0.842
6	-0.312	-0.334	7.9833	0.239
7	-0.013	-0.048	7.9947	0.333
8	0.006	-0.091	7.9969	0.434
9	-0.074	-0.208	8.3561	0.499
10	-0.025	-0.159	8.3969	0.590
11	0.135	-0.012	9.6372	0.563
12	0.385	0.250	20.043	0.066
13	-0.007	-0.058	20.047	0.094
14	-0.172	-0.214	22.229	0.074
15	0.057	0.068	22.473	0.096
16	-0.081	-0.076	22.987	0.114
17	0.027	0.121	23.046	0.148
18	-0.174	-0.051	25.539	0.111
19	-0.040	-0.131	25.672	0.140
20	0.065	0.014	26.039	0.165
21	-0.084	-0.010	26.675	0.182
22	0.118	0.121	27.971	0.177
23	0.034	-0.074	28.086	0.213
24	0.266	0.124	35.190	0.066

Dependent Variable: M_RR_C
Method: Least Squares
Date: 05/05/14 Time: 15:06
Sample (adjusted): 2009M04 2014M03
Included observations: 60 after adjustments
Convergence achieved after 23 iterations
MA Backcast: 2009M01 2009M03

Variable	Coefficient	Std. Error	t-Statistic	Prob.
HS	27.91007	11.44662	2.438280	0.0181
D_2013M7M8	-39.66611	13.52186	-2.933479	0.0049
C	3390.762	5942.252	0.570619	0.5706
AR(1)	1.271971	0.082482	15.42115	0.0000
AR(3)	-0.275858	0.087435	-3.154998	0.0026
MA(3)	0.311112	0.144173	2.157913	0.0354

R-squared	0.992110	Mean dependent var	4749.567
Adjusted R-squared	0.991379	S.D. dependent var	238.7316
S.E. of regression	22.16584	Akaike info criterion	9.129621
Sum squared resid	26531.52	Schwarz criterion	9.339056
Log likelihood	-267.8886	Hannan-Quinn criter.	9.211542
F-statistic	1357.980	Durbin-Watson stat	1.775513
Prob(F-statistic)	0.000000		

Inverted AR Roots	.99	.69	-.41
Inverted MA Roots	.34+.59i	.34-.59i	-.68

Variable Name	Definition
HS	Housing Starts
D_2013M7M8	Dummy, July - August 2013
C	Constant
AR(1)	Autoregressive Term, lag 1
AR(3)	Autoregressive Term, lag 3
MA(3)	Moving Average Term, lag 3

Heteroskedasticity Test: Breusch-Pagan-Godfrey

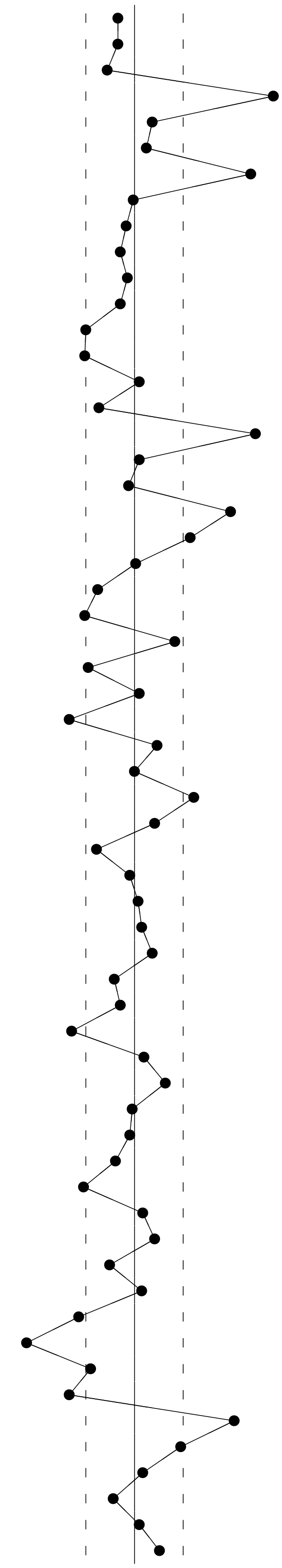
F-statistic	1.391402	Prob. F(2,57)	0.2570
Obs*R-squared	2.792914	Prob. Chi-Square(2)	0.2475
Scaled explained SS	3.720251	Prob. Chi-Square(2)	0.1557

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 12/15/14 Time: 12:17
Sample: 2009M04 2014M03
Included observations: 60

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	354.5338	907.2306	0.390787	0.6974
HS	18.82533	305.3589	0.061650	0.9511
D_2013M7M8	965.2381	578.7355	1.667840	0.1008

R-squared	0.046549	Mean dependent var	442.1919
Adjusted R-squared	0.013094	S.D. dependent var	808.7053
S.E. of regression	803.3932	Akaike info criterion	16.26427
Sum squared resid	36790114	Schwarz criterion	16.36899
Log likelihood	-484.9282	Hannan-Quinn criter.	16.30523
F-statistic	1.391402	Durbin-Watson stat	2.207465
Prob(F-statistic)	0.257045		

obs	Actual	Fitted	Residual	Residual Plot
2009M04	4926.00	4933.69	-7.68541	
2009M05	4900.00	4907.38	-7.37933	
2009M06	4867.00	4879.31	-12.3069	
2009M07	4912.00	4849.66	62.3374	
2009M08	4909.00	4901.03	7.96927	
2009M09	4911.00	4905.44	5.56367	
2009M10	4970.00	4917.32	52.6757	
2009M11	4990.00	4990.54	-0.53639	
2009M12	5012.00	5015.60	-3.59814	
2010M01	5033.00	5039.51	-6.50799	
2010M02	5035.00	5038.08	-3.08412	
2010M03	5025.00	5031.52	-6.51828	
2010M04	4996.00	5017.95	-21.9530	
2010M05	4951.00	4973.42	-22.4222	
2010M06	4921.00	4919.00	1.99771	
2010M07	4867.00	4883.15	-16.1493	
2010M08	4890.00	4835.62	54.3845	
2010M09	4882.00	4879.63	2.36507	
2010M10	4880.00	4882.54	-2.53914	
2010M11	4922.00	4878.66	43.3440	
2010M12	4944.00	4918.67	25.3301	
2011M01	4944.00	4943.43	0.56796	
2011M02	4949.00	4965.65	-16.6520	
2011M03	4939.00	4961.43	-22.4340	
2011M04	4955.00	4936.91	18.0937	
2011M05	4922.00	4942.69	-20.6940	
2011M06	4904.00	4901.75	2.25472	
2011M07	4854.00	4883.59	-29.5870	
2011M08	4843.00	4832.92	10.0829	
2011M09	4831.00	4830.93	0.07376	
2011M10	4848.00	4821.46	26.5429	
2011M11	4850.00	4840.88	9.11765	
2011M12	4824.00	4841.32	-17.3159	
2012M01	4817.00	4819.38	-2.38109	
2012M02	4803.00	4801.63	1.37114	
2012M03	4788.00	4785.03	2.96997	
2012M04	4776.00	4767.72	8.28178	
2012M05	4761.00	4770.12	-9.12271	
2012M06	4749.00	4755.56	-6.56287	
2012M07	4715.00	4743.58	-28.5776	
2012M08	4697.00	4692.78	4.21613	
2012M09	4687.00	4673.23	13.7741	
2012M10	4664.00	4664.86	-0.85681	
2012M11	4650.00	4652.15	-2.15439	
2012M12	4632.00	4640.60	-8.60316	
2013M01	4596.00	4619.27	-23.2723	
2013M02	4580.00	4576.22	3.78395	
2013M03	4567.00	4557.96	9.03531	
2013M04	4538.00	4549.12	-11.1175	
2013M05	4523.00	4519.94	3.05653	
2013M06	4482.00	4507.32	-25.3185	
2013M07	4365.00	4413.50	-48.5001	
2013M08	4317.00	4336.86	-19.8574	
2013M09	4288.00	4317.37	-29.3742	
2013M10	4291.00	4245.89	45.1087	
2013M11	4278.00	4256.87	21.1294	
2013M12	4259.00	4255.32	3.67879	
2014M01	4247.00	4256.63	-9.63196	
2014M02	4245.00	4242.93	2.07238	
2014M03	4253.00	4241.58	11.4243	



Correlogram of Residuals

Date: 12/15/14 Time: 12:16
Sample: 2009M04 2014M03
Included observations: 60
Q-statistic probabilities adjusted for 3 ARMA term(s)

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	0.109	0.109	0.7441	
		2	0.030	0.018	0.8012	
		3	-0.030	-0.035	0.8588	
		4	-0.146	-0.141	2.2713	0.132
		5	0.007	0.040	2.2748	0.321
		6	-0.105	-0.107	3.0389	0.386
		7	-0.140	-0.131	4.4049	0.354
		8	-0.084	-0.075	4.9081	0.427
		9	-0.201	-0.192	7.8648	0.248
		10	0.088	0.092	8.4394	0.295
		11	0.022	-0.035	8.4767	0.388
		12	0.119	0.088	9.5786	0.386
		13	0.268	0.200	15.260	0.123
		14	0.170	0.157	17.597	0.091
		15	-0.063	-0.156	17.923	0.118
		16	0.027	0.061	17.984	0.158
		17	-0.026	0.035	18.043	0.205
		18	0.004	0.011	18.045	0.260
		19	-0.099	-0.055	18.935	0.272
		20	-0.093	0.014	19.741	0.288
		21	-0.052	0.045	20.000	0.333
		22	-0.086	-0.028	20.719	0.353
		23	-0.046	-0.064	20.927	0.401
		24	0.080	0.022	21.581	0.424
		25	0.127	0.146	23.288	0.386
		26	0.036	-0.138	23.433	0.436
		27	0.037	-0.037	23.585	0.486
		28	0.036	0.063	23.735	0.535

Dependent Variable: M_RR_UPC
Method: Least Squares
Date: 05/16/14 Time: 11:47
Sample (adjusted): 2010M01 2014M03
Included observations: 51 after adjustments
Convergence achieved after 15 iterations
MA Backcast: 2009M01 2009M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_BC	0.003127	0.000268	11.65830	0.0000
C	0.407783	0.317479	1.284439	0.2057
TREND*(JAN+FEB+MA	0.006475	0.002679	2.416503	0.0199
AR(1)	0.773264	0.135821	5.693246	0.0000
AR(3)	-0.218537	0.095318	-2.292728	0.0267
AR(12)	0.250382	0.090430	2.768793	0.0082
MA(12)	0.905869	0.026373	34.34797	0.0000

R-squared	0.987807	Mean dependent var	2.054207
Adjusted R-squared	0.986144	S.D. dependent var	1.208325
S.E. of regression	0.142233	Akaike info criterion	-0.935826
Sum squared resid	0.890130	Schwarz criterion	-0.670674
Log likelihood	30.86357	Hannan-Quinn criter.	-0.834503
F-statistic	594.0970	Durbin-Watson stat	2.061081
Prob(F-statistic)	0.000000		

Inverted AR Roots	.95	.86+.46i	.86-.46i	.54+.75i
	.54-.75i	.07-.86i	.07+.86i	-.39-.74i
	-.39+.74i	-.73-.43i	-.73+.43i	-.86
Inverted MA Roots	.96-.26i	.96+.26i	.70+.70i	.70-.70i
	.26-.96i	.26+.96i	-.26-.96i	-.26+.96i
	-.70-.70i	-.70-.70i	-.96+.26i	-.96-.26i

Variable Name	Definition
EDD_BC	Bill Cycle EDD
C	Constant
TREND*(JAN+FEB+MAR)	Interaction Varibable - Linear Trend * January - March
AR(1)	Autoregressive Term, lag 1
AR(3)	Autoregressive Term, lag 3
AR(12)	Autoregressive Term, lag 12
MA(12)	Moving Average Term, lag 12

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	1.426957	Prob. F(2,48)	0.2500
Obs*R-squared	2.862113	Prob. Chi-Square(2)	0.2391
Scaled explained SS	1.972936	Prob. Chi-Square(2)	0.3729

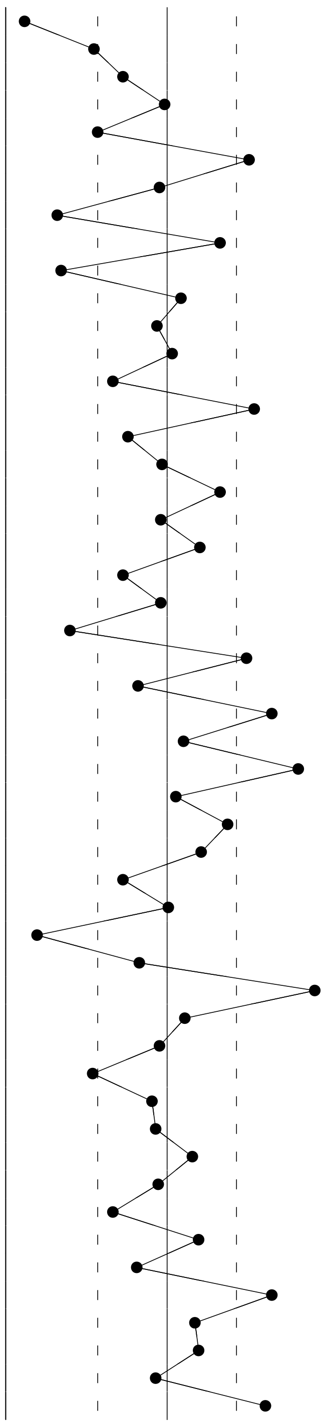
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 12/15/14 Time: 12:32
Sample: 2010M01 2014M03
Included observations: 51

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.010841	0.005800	1.868959	0.0677
EDD_BC	1.66E-05	1.00E-05	1.658746	0.1037
TREND*(JAN+FEB+MA	-0.000343	0.000243	-1.411392	0.1646

R-squared	0.056120	Mean dependent var	0.017454
Adjusted R-squared	0.016792	S.D. dependent var	0.023990
S.E. of regression	0.023788	Akaike info criterion	-4.582276
Sum squared resid	0.027161	Schwarz criterion	-4.468639
Log likelihood	119.8480	Hannan-Quinn criter.	-4.538852
F-statistic	1.426957	Durbin-Watson stat	2.298340
Prob(F-statistic)	0.250037		

obs	Actual	Fitted	Residual
2010M01	2.58014	2.87410	-0.29395
2010M02	2.21025	2.36050	-0.15024
2010M03	1.93055	2.02241	-0.09186
2010M04	1.70698	1.71295	-0.00597
2010M05	1.31937	1.46374	-0.14437
2010M06	1.03405	0.86545	0.16860
2010M07	0.92594	0.94141	-0.01547
2010M08	0.79003	1.01743	-0.22739
2010M09	0.89056	0.78071	0.10985
2010M10	0.99100	1.21029	-0.21929
2010M11	1.37919	1.35009	0.02910
2010M12	2.03142	2.05220	-0.02078
2011M01	2.75148	2.74077	0.01071
2011M02	2.99296	3.10529	-0.11233
2011M03	2.61868	2.43994	0.17874
2011M04	2.18040	2.25992	-0.07952
2011M05	1.41300	1.42271	-0.00972
2011M06	1.27708	1.16865	0.10842
2011M07	0.99278	1.00571	-0.01293
2011M08	0.81632	0.74911	0.06721
2011M09	0.94710	1.03694	-0.08984
2011M10	1.02128	1.03552	-0.01425
2011M11	1.66464	1.86534	-0.20069
2011M12	2.08764	1.92383	0.16380
2012M01	3.21887	3.27882	-0.05996
2012M02	3.19962	2.98414	0.21548
2012M03	2.86355	2.83077	0.03278
2012M04	2.08655	1.81627	0.27028
2012M05	1.61820	1.60110	0.01710
2012M06	1.26081	1.13562	0.12519
2012M07	0.97839	0.90727	0.07112
2012M08	0.88514	0.97739	-0.09224
2012M09	0.89786	0.89409	0.00377
2012M10	1.16332	1.43066	-0.26734
2012M11	1.91651	1.97425	-0.05774
2012M12	3.12976	2.82643	0.30333
2013M01	4.02264	3.98556	0.03708
2013M02	4.38885	4.40455	-0.01570
2013M03	3.45436	3.60852	-0.15417
2013M04	2.92282	2.95337	-0.03055
2013M05	1.87548	1.90019	-0.02471
2013M06	1.34283	1.29132	0.05151
2013M07	0.94091	0.95916	-0.01825
2013M08	0.71768	0.83082	-0.11314
2013M09	0.95612	0.89093	0.06519
2013M10	1.15419	1.21639	-0.06220
2013M11	2.28960	2.07399	0.21562
2013M12	3.95798	3.90114	0.05684
2014M01	5.32458	5.25995	0.06463
2014M02	4.98771	5.01099	-0.02328
2014M03	4.65739	4.45413	0.20326

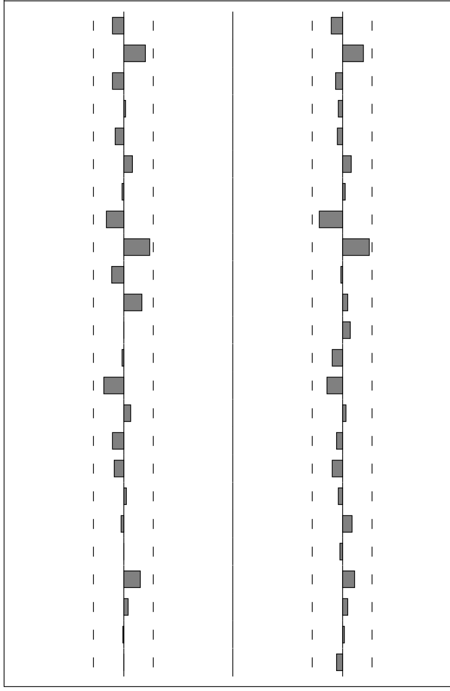
Residual Plot



Correlogram of Residuals

Date: 12/15/14 Time: 12:32
Sample: 2010M01 2014M03
Included observations: 51
Q-statistic probabilities adjusted for 4 ARMA term(s)

Autocorrelation | Partial Correlation



	AC	PAC	Q-Stat	Prob
1	-0.102	-0.102	0.5651	
2	0.208	0.199	2.9406	
3	-0.098	-0.064	3.4869	
4	0.020	-0.035	3.5100	
5	-0.076	-0.048	3.8529	0.050
6	0.089	0.082	4.3317	0.115
7	-0.011	0.025	4.3386	0.227
8	-0.163	-0.218	6.0103	0.198
9	0.250	0.260	10.049	0.074
10	-0.107	-0.010	10.804	0.095
11	0.173	0.052	12.831	0.076
12	0.007	0.075	12.835	0.118
13	-0.015	-0.098	12.851	0.169
14	-0.188	-0.142	15.420	0.117
15	0.071	0.035	15.795	0.149
16	-0.105	-0.052	16.654	0.163
17	-0.088	-0.096	17.270	0.187
18	0.029	-0.035	17.341	0.238
19	-0.020	0.090	17.375	0.297
20	0.006	-0.024	17.379	0.361
21	0.160	0.116	19.686	0.291
22	0.043	0.056	19.861	0.341
23	-0.005	0.022	19.863	0.403
24	0.005	-0.050	19.866	0.466

Dependent Variable: M_LLF_C_T
Method: Least Squares
Date: 05/13/14 Time: 10:57
Sample (adjusted): 2012M02 2014M03
Included observations: 26 after adjustments
Convergence achieved after 11 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LN_TREND	651.5026	116.6753	5.583894	0.0001
EMPNM	109.8208	16.08718	6.826603	0.0000
C	-55063.69	8559.738	-6.432871	0.0000
SEP	131.5946	44.33069	2.968475	0.0117
OCT	420.4783	58.85620	7.144164	0.0000
NOV	497.7215	58.30451	8.536586	0.0000
DEC	529.2327	55.00893	9.620851	0.0000
JAN	515.5815	55.37197	9.311236	0.0000
FEB	455.6590	56.53731	8.059438	0.0000
MAR	351.3789	52.83260	6.650797	0.0000
APR	100.4721	41.79759	2.403776	0.0333
AR(1)	0.543739	0.232901	2.334636	0.0378
AR(2)	-0.608157	0.262305	-2.318508	0.0389
AR(3)	0.321493	0.159017	2.021749	0.0661

R-squared	0.996923	Mean dependent var	7358.462
Adjusted R-squared	0.993590	S.D. dependent var	696.1128
S.E. of regression	55.73121	Akaike info criterion	11.18269
Sum squared resid	37271.61	Schwarz criterion	11.86013
Log likelihood	-131.3750	Hannan-Quinn criter.	11.37777
F-statistic	299.1030	Durbin-Watson stat	2.156611
Prob(F-statistic)	0.000000		

Inverted AR Roots	.53	.01+.78i	.01-.78i

Variable Name	Definition
LN_TREND	Logarithmic Trend
EMPNM	Non-Manufacturing Employment
C	Constant
SEP	September
OCT	October
NOV	November
DEC	December
JAN	January
FEB	February
MAR	March
APR	April
AR(1)	Autoregressive Term, lag 1
AR(2)	Autoregressive Term, lag 2
AR(3)	Autoregressive Term, lag 3

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	1.063809	Prob. F(10,15)	0.4427
Obs*R-squared	10.78826	Prob. Chi-Square(10)	0.3743
Scaled explained SS	2.017285	Prob. Chi-Square(10)	0.9962

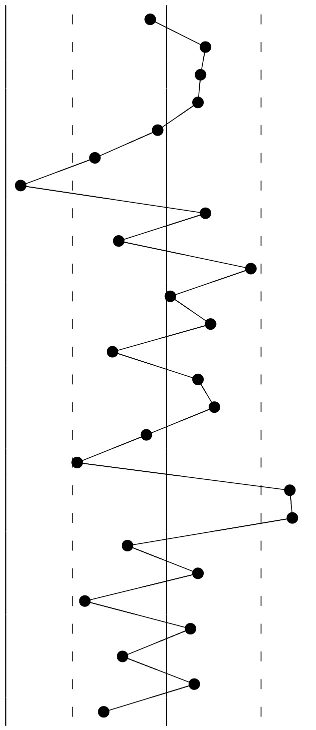
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 12/15/14 Time: 12:23
Sample: 2012M02 2014M03
Included observations: 26

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	114889.4	161259.4	0.712451	0.4871
LN_TREND	1637.899	1529.005	1.071219	0.3010
EMPNM	-211.2603	299.5907	-0.705163	0.4915
SEP	-2704.002	1533.605	-1.763167	0.0982
OCT	-2809.425	1570.023	-1.789417	0.0938
NOV	-975.7359	1568.569	-0.622055	0.5432
DEC	-3299.185	1558.758	-2.116547	0.0514
JAN	-2713.919	1558.059	-1.741858	0.1020
FEB	-2334.888	1304.525	-1.789838	0.0937
MAR	-2079.556	1308.560	-1.589194	0.1329
APR	-2052.303	1532.115	-1.339522	0.2003

R-squared	0.414933	Mean dependent var	1433.523
Adjusted R-squared	0.024888	S.D. dependent var	1937.031
S.E. of regression	1912.774	Akaike info criterion	18.24660
Sum squared resid	54880574	Schwarz criterion	18.77888
Log likelihood	-226.2059	Hannan-Quinn criter.	18.39988
F-statistic	1.063809	Durbin-Watson stat	1.624595
Prob(F-statistic)	0.442710		

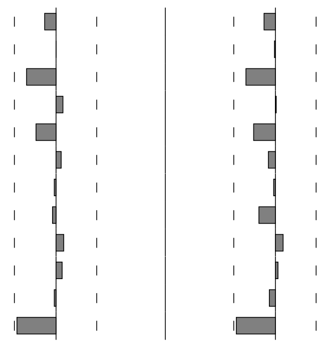
obs	Actual	Fitted	Residual
2012M02	6460.00	6469.89	-9.89179
2012M03	6498.00	6474.96	23.0361
2012M04	6488.00	6467.83	20.1679
2012M05	6469.00	6450.65	18.3542
2012M06	6472.00	6477.58	-5.57509
2012M07	6479.00	6521.39	-42.3864
2012M08	6473.00	6560.04	-87.0417
2012M09	6750.00	6727.18	22.8190
2012M10	7046.00	7074.63	-28.6288
2012M11	7220.00	7170.00	49.9977
2012M12	7341.00	7338.41	2.59248
2013M01	7416.00	7390.13	25.8700
2013M02	7446.00	7478.03	-32.0291
2013M03	7485.00	7466.40	18.5988
2013M04	7426.00	7397.26	28.7409
2013M05	7382.00	7394.25	-12.2520
2013M06	7375.00	7428.09	-53.0916
2013M07	7588.00	7514.78	73.2241
2013M08	7747.00	7672.33	74.6699
2013M09	7791.00	7814.44	-23.4370
2013M10	8053.00	8034.00	19.0010
2013M11	8224.00	8272.86	-48.8610
2013M12	8404.00	8390.08	13.9183
2014M01	8437.00	8463.51	-26.5079
2014M02	8449.00	8432.67	16.3260
2014M03	8401.00	8438.61	-37.6140

Residual Plot



Correlogram of Residuals

Date: 12/15/14 Time: 12:22
Sample: 2012M02 2014M03
Included observations: 26
Q-statistic probabilities adjusted for 3 ARMA term(s)



Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	-0.099	-0.099	0.2831	
		2	0.005	-0.004	0.2839	
		3	-0.271	-0.273	2.6029	
		4	0.066	0.013	2.7481	0.097
		5	-0.184	-0.200	3.9189	0.141
		6	0.051	-0.064	4.0122	0.260
		7	-0.012	-0.012	4.0175	0.404
		8	-0.029	-0.155	4.0511	0.542
		9	0.079	0.081	4.3210	0.633
		10	0.064	0.030	4.5071	0.720
		11	-0.014	-0.050	4.5164	0.808
		12	-0.365	-0.365	11.441	0.247

Dependent Variable: M_LLF_UPC_T
Method: Least Squares
Date: 05/06/14 Time: 10:21
Sample (adjusted): 2010M12 2014M03
Included observations: 40 after adjustments
Convergence achieved after 47 iterations
MA Backcast: 2010M11

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_BC	0.071041	0.007209	9.854832	0.0000
C	53.30374	31.50745	1.691782	0.1001
LLF_PRICE	-2.912917	1.724785	-1.688858	0.1007
D_2012M2	-15.27600	3.073893	-4.969594	0.0000
AR(12)	0.599412	0.108324	5.533491	0.0000
AR(1)	0.267759	0.115444	2.319380	0.0267
MA(1)	0.470219	0.191473	2.455793	0.0195

R-squared	0.991815	Mean dependent var	68.82742
Adjusted R-squared	0.990326	S.D. dependent var	39.74980
S.E. of regression	3.909570	Akaike info criterion	5.722360
Sum squared resid	504.3963	Schwarz criterion	6.017914
Log likelihood	-107.4472	Hannan-Quinn criter.	5.829223
F-statistic	666.4318	Durbin-Watson stat	1.855506
Prob(F-statistic)	0.000000		

Inverted AR Roots	.98	.85+.48i	.85-.48i	.50+.83i
	.50-.83i	.02+.96i	.02-.96i	-.46+.83i
	-.46-.83i	-.81+.48i	-.81-.48i	-.94
Inverted MA Roots	-.47			

Variable Name	Definition
EDD_BC	Bill Cycle EDD
C	Constant
LLF_PRICE	LLF Natural Gas Price
D_2012M2	Dummy, February 2012
AR(12)	Autoregressive Term, lag 12
AR(1)	Autoregressive Term, lag 1
MA(1)	Moving Average Term, lag 1

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	2.462300	Prob. F(3,36)	0.0782
Obs*R-squared	6.810259	Prob. Chi-Square(3)	0.0782
Scaled explained SS	6.228056	Prob. Chi-Square(3)	0.1010

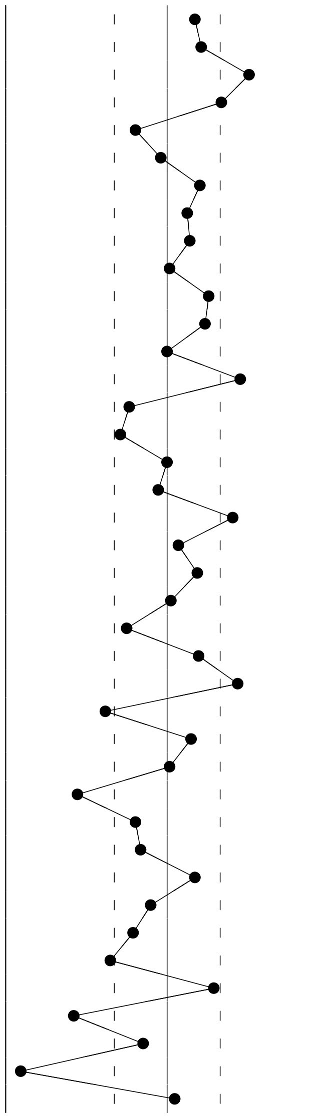
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 12/15/14 Time: 12:37
Sample: 2010M12 2014M03
Included observations: 40

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	9.789746	85.21061	0.114889	0.9092
EDD_BC	0.017763	0.006962	2.551475	0.0151
LLF_PRICE	-0.607126	5.969691	-0.101701	0.9196
D_2012M2	-14.04198	20.39769	-0.688410	0.4956

R-squared	0.170256	Mean dependent var	12.60991
Adjusted R-squared	0.101111	S.D. dependent var	20.93462
S.E. of regression	19.84806	Akaike info criterion	8.908729
Sum squared resid	14182.04	Schwarz criterion	9.077617
Log likelihood	-174.1746	Hannan-Quinn criter.	8.969794
F-statistic	2.462300	Durbin-Watson stat	2.670881
Prob(F-statistic)	0.078214		

obs	Actual	Fitted	Residual
2010M12	107.698	105.655	2.04345
2011M01	136.170	133.698	2.47235
2011M02	138.097	132.062	6.03533
2011M03	115.535	111.570	3.96451
2011M04	85.7210	88.0081	-2.28710
2011M05	48.5048	48.9342	-0.42944
2011M06	32.4837	30.0324	2.45135
2011M07	25.9367	24.4389	1.49785
2011M08	24.5452	22.9112	1.63394
2011M09	26.1412	25.9775	0.16371
2011M10	37.8635	34.8257	3.03777
2011M11	65.1880	62.4165	2.77151
2011M12	87.3420	87.3494	-0.00734
2012M01	125.569	120.191	5.37888
2012M02	102.495	105.331	-2.83607
2012M03	96.1655	99.5955	-3.42996
2012M04	68.1127	68.1283	-0.01559
2012M05	45.5659	46.2268	-0.66091
2012M06	31.5725	26.7270	4.84551
2012M07	24.0597	23.1830	0.87675
2012M08	23.3326	21.1238	2.20876
2012M09	24.9039	24.6417	0.26213
2012M10	36.9436	39.9303	-2.98672
2012M11	67.4455	65.1024	2.34305
2012M12	98.6540	93.3969	5.25715
2013M01	117.151	121.729	-4.57799
2013M02	119.896	118.136	1.75946
2013M03	99.0461	98.8210	0.22516
2013M04	74.1852	80.8000	-6.61481
2013M05	42.5468	44.9159	-2.36908
2013M06	25.5982	27.5810	-1.98277
2013M07	20.2633	18.2401	2.02312
2013M08	19.7776	20.9914	-1.21378
2013M09	20.4850	22.9918	-2.50681
2013M10	29.6501	33.8703	-4.22019
2013M11	62.8092	59.3296	3.47961
2013M12	98.7839	105.694	-6.91046
2014M01	124.255	126.044	-1.78887
2014M02	112.580	123.436	-10.8564
2014M03	110.022	109.488	0.53334

Residual Plot



Correlogram of Residuals

Date: 12/15/14 Time: 12:36
Sample: 2010M12 2014M03
Included observations: 40
Q-statistic probabilities adjusted for 3 ARMA term(s)

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	0.068	0.068	0.1978	
		2	0.162	0.158	1.3620	
		3	0.044	0.025	1.4492	
		4	0.082	0.054	1.7619	0.184
		5	0.128	0.114	2.5482	0.280
		6	0.133	0.104	3.4192	0.331
		7	0.024	-0.026	3.4488	0.486
		8	0.229	0.197	6.2116	0.286
		9	-0.001	-0.038	6.2117	0.400
		10	0.099	0.020	6.7556	0.455
		11	0.205	0.196	9.2013	0.326
		12	-0.137	-0.230	10.326	0.325
		13	0.118	0.061	11.190	0.343
		14	-0.112	-0.137	12.005	0.363
		15	-0.102	-0.170	12.703	0.391
		16	0.048	0.045	12.864	0.458
		17	0.014	0.029	12.879	0.536
		18	-0.047	-0.075	13.045	0.599
		19	-0.060	-0.123	13.329	0.649
		20	-0.168	-0.019	15.708	0.545

Dependent Variable: M_HLF_C_T
Method: Least Squares
Date: 05/16/14 Time: 11:40
Sample (adjusted): 2009M01 2014M03
Included observations: 63 after adjustments
Convergence achieved after 17 iterations
MA Backcast: 2008M11 2008M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
D_2012M9_	-413.9347	10.30871	-40.15387	0.0000
D_2013M7_	95.13334	7.202404	13.20855	0.0000
EMPM	8.984469	3.688044	2.436107	0.0182
C	1458.718	192.6913	7.570235	0.0000
D_2012M9	46.52601	9.810454	4.742493	0.0000
D_2012M10	-36.84576	8.684032	-4.242932	0.0001
D_2013M8	-19.65417	7.287979	-2.696793	0.0094
D_2009M1_2012M8*TREN	-3.746644	0.269517	-13.90133	0.0000
MA(1)	0.662368	0.126200	5.248561	0.0000
MA(2)	0.377907	0.130355	2.899070	0.0054

R-squared	0.996819	Mean dependent var	1746.683
Adjusted R-squared	0.996278	S.D. dependent var	144.6211
S.E. of regression	8.822629	Akaike info criterion	7.337134
Sum squared resid	4125.455	Schwarz criterion	7.677314
Log likelihood	-221.1197	Hannan-Quinn criter.	7.470929
F-statistic	1845.153	Durbin-Watson stat	1.877408
Prob(F-statistic)	0.000000		
Inverted MA Roots	-.33+.52i	-.33-.52i	

Variable Name	Definition
D_2012M9_	Dummy, September 2012 and forward
D_2013M7_	Dummy, July 2013 and forward
EMPM	Manufacturing Employment
C	Constant
D_2012M9	Dummy, September 2012
D_2012M10	Dummy, October 2012
D_2013M8	Dummy, August 2013
D_2009M1_2012M8*TREND	Interaction Variable - Linear Trend * Dummy, January 2009 - August 2012
MA(1)	Moving Average Term, lag 1
MA(2)	Moving Average Term, lag 2

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	0.189468	Prob. F(7,55)	0.9865
Obs*R-squared	1.483418	Prob. Chi-Square(7)	0.9829
Scaled explained SS	1.187244	Prob. Chi-Square(7)	0.9912

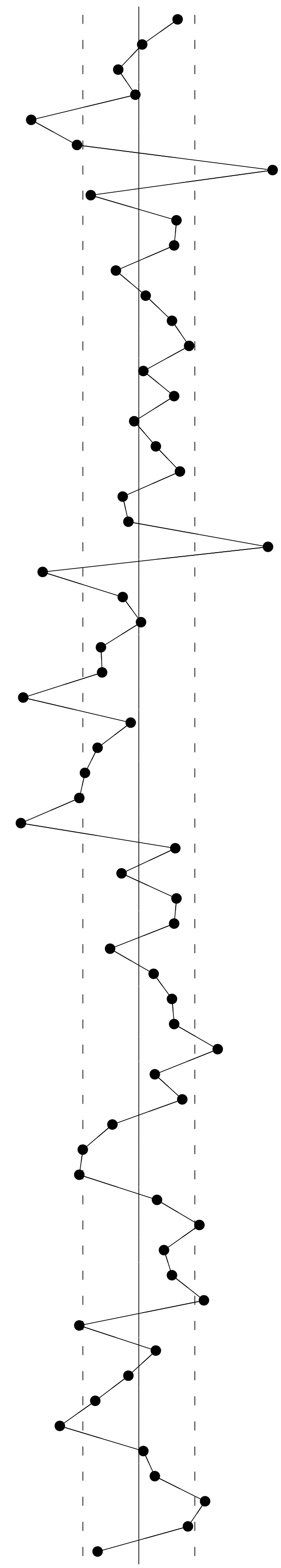
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 12/15/14 Time: 12:28
Sample: 2009M01 2014M03
Included observations: 63

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	835.7534	1142.017	0.731822	0.4674
D_2012M9_	-55.21974	64.12861	-0.861078	0.3929
D_2013M7_	-1.468938	52.67347	-0.027888	0.9779
EMPM	-14.41972	21.83710	-0.660331	0.5118
D_2012M9	-31.20676	110.8615	-0.281493	0.7794
D_2012M10	27.81417	110.7844	0.251066	0.8027
D_2013M8	-1.556527	110.5009	-0.014086	0.9888
D_2009M1_2012M8*TREN	-1.136747	1.625932	-0.699136	0.4874

R-squared	0.023546	Mean dependent var	65.48341
Adjusted R-squared	-0.100730	S.D. dependent var	99.27131
S.E. of regression	104.1512	Akaike info criterion	12.24773
Sum squared resid	596610.5	Schwarz criterion	12.51987
Log likelihood	-377.8035	Hannan-Quinn criter.	12.35477
F-statistic	0.189468	Durbin-Watson stat	1.893743
Prob(F-statistic)	0.986496		

obs	Actual	Fitted	Residual
2009M01	1958.00	1951.92	6.08014
2009M02	1944.00	1943.40	0.59713
2009M03	1928.00	1931.17	-3.16822
2009M04	1916.00	1916.59	-0.58927
2009M05	1893.00	1909.89	-16.8875
2009M06	1884.00	1893.66	-9.66315
2009M07	1906.00	1885.02	20.9818
2009M08	1895.00	1902.48	-7.47945
2009M09	1896.00	1889.97	6.02807
2009M10	1888.00	1882.35	5.64789
2009M11	1879.00	1882.56	-3.55581
2009M12	1873.00	1871.89	1.10897
2010M01	1872.00	1866.82	5.18449
2010M02	1875.00	1867.12	7.88408
2010M03	1867.00	1866.32	0.68054
2010M04	1864.00	1858.47	5.53009
2010M05	1854.00	1854.75	-0.74868
2010M06	1851.00	1848.24	2.76225
2010M07	1850.00	1843.60	6.40327
2010M08	1841.00	1843.55	-2.55480
2010M09	1834.00	1835.61	-1.60642
2010M10	1849.00	1828.71	20.2945
2010M11	1826.00	1841.21	-15.2109
2010M12	1821.00	1823.56	-2.55611
2011M01	1818.00	1817.63	0.36896
2011M02	1814.00	1819.95	-5.94755
2011M03	1806.00	1811.69	-5.69396
2011M04	1786.00	1804.18	-18.1802
2011M05	1790.00	1791.22	-1.22451
2011M06	1787.00	1793.44	-6.43521
2011M07	1783.00	1791.48	-8.47633
2011M08	1775.00	1784.43	-9.43326
2011M09	1761.00	1779.49	-18.4912
2011M10	1775.00	1769.31	5.69492
2011M11	1776.00	1778.65	-2.64737
2011M12	1785.00	1779.12	5.88152
2012M01	1784.00	1778.37	5.62654
2012M02	1774.00	1778.44	-4.43959
2012M03	1771.00	1768.59	2.41072
2012M04	1772.00	1766.82	5.18235
2012M05	1773.00	1767.46	5.53639
2012M06	1777.00	1764.65	12.3501
2012M07	1768.00	1765.50	2.49728
2012M08	1764.00	1757.23	6.77023
2012M09	1549.00	1553.11	-4.10745
2012M10	1455.00	1463.75	-8.74813
2012M11	1483.00	1492.36	-9.35847
2012M12	1492.00	1489.13	2.87436
2013M01	1505.00	1495.38	9.61555
2013M02	1508.00	1504.00	3.99567
2013M03	1508.00	1502.82	5.17879
2013M04	1511.00	1500.69	10.3113
2013M05	1496.00	1505.45	-9.45119
2013M06	1498.00	1495.33	2.66913
2013M07	1591.00	1592.60	-1.60090
2013M08	1568.00	1574.91	-6.90909
2013M09	1577.00	1589.39	-12.3922
2013M10	1584.00	1583.29	0.71118
2013M11	1593.00	1590.51	2.49215
2013M12	1608.00	1597.58	10.4168
2014M01	1612.00	1604.34	7.65792
2014M02	1600.00	1606.40	-6.40387

Residual Plot

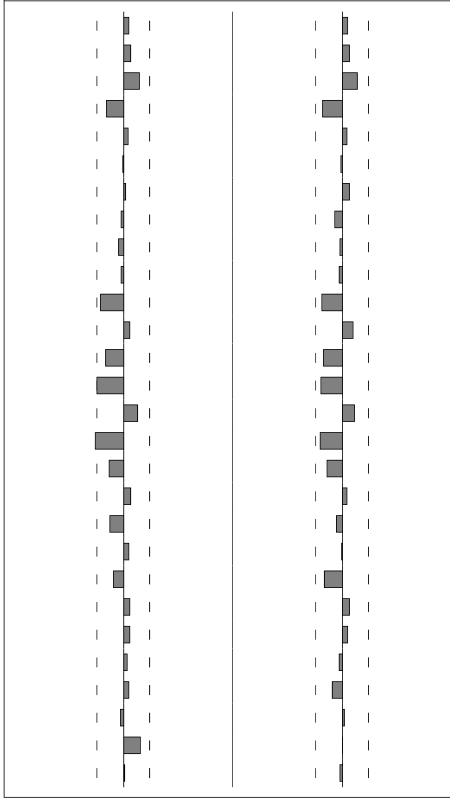


obs	Actual	Fitted	Residual	Residual Plot
2014M03	1600.00	1596.95	3.04849	

Correlogram of Residuals

Date: 12/15/14 Time: 12:28
Sample: 2009M01 2014M03
Included observations: 63
Q-statistic probabilities adjusted for 2 ARMA term(s)

Autocorrelation | Partial Correlation



	AC	PAC	Q-Stat	Prob
1	0.056	0.056	0.2036	
2	0.072	0.069	0.5497	
3	0.148	0.142	2.0502	0.152
4	-0.160	-0.183	3.8211	0.148
5	0.045	0.047	3.9629	0.266
6	-0.008	-0.013	3.9677	0.410
7	0.019	0.070	3.9952	0.550
8	-0.018	-0.072	4.0197	0.674
9	-0.042	-0.024	4.1563	0.762
10	-0.020	-0.031	4.1869	0.840
11	-0.215	-0.191	7.8354	0.551
12	0.064	0.100	8.1659	0.613
13	-0.166	-0.176	10.431	0.492
14	-0.248	-0.197	15.587	0.211
15	0.138	0.117	17.205	0.190
16	-0.263	-0.208	23.243	0.056
17	-0.135	-0.142	24.857	0.052
18	0.072	0.047	25.326	0.064
19	-0.124	-0.053	26.765	0.062
20	0.056	-0.003	27.061	0.078
21	-0.094	-0.164	27.921	0.085
22	0.059	0.069	28.272	0.103
23	0.063	0.055	28.682	0.122
24	0.038	-0.027	28.832	0.150
25	0.054	-0.092	29.148	0.175
26	-0.031	0.024	29.252	0.211
27	0.158	0.005	32.105	0.155
28	0.010	-0.021	32.116	0.189

Dependent Variable: M_HLF_UPC_T
Method: Least Squares
Date: 05/16/14 Time: 11:59
Sample (adjusted): 2010M06 2014M03
Included observations: 46 after adjustments
Convergence achieved after 22 iterations
MA Backcast: 2010M05

Variable	Coefficient	Std. Error	t-Statistic	Prob.
HLF_PRICE	-10.41505	3.069239	-3.393365	0.0016
EDD_BC	0.033296	0.004236	7.861106	0.0000
C	196.9559	37.41215	5.264492	0.0000
D_2012M9	18.31973	4.926896	3.718311	0.0006
TREND	0.398958	0.174885	2.281264	0.0282
AR(2)	0.242708	0.183496	1.322685	0.1938
AR(6)	-0.364519	0.146668	-2.485335	0.0175
MA(1)	0.493961	0.172487	2.863755	0.0068

R-squared	0.964646	Mean dependent var	124.3842
Adjusted R-squared	0.958134	S.D. dependent var	25.16022
S.E. of regression	5.148087	Akaike info criterion	6.271898
Sum squared resid	1007.106	Schwarz criterion	6.589923
Log likelihood	-136.2537	Hannan-Quinn criter.	6.391032
F-statistic	148.1221	Durbin-Watson stat	1.924334
Prob(F-statistic)	0.000000		

Inverted AR Roots	.77-.39i	.77+.39i	.00+.80i	-.00-.80i
	-.77-.39i	-.77+.39i		
Inverted MA Roots	-.49			

Variable Name	Definition
HLF_PRICE	HLF Natural Gas Price
EDD_BC	Bill Cycle EDD
C	Constant
D_2012M9	Dummy, September 2012
TREND	Linear Trend
AR(2)	Autoregressive Term, lag 2
AR(6)	Autoregressive Term, lag 6
MA(1)	Moving Average Term, lag 1

Heteroskedasticity Test: Harvey

F-statistic	2.586124	Prob. F(4,41)	0.0509
Obs*R-squared	9.267728	Prob. Chi-Square(4)	0.0547
Scaled explained SS	12.62722	Prob. Chi-Square(4)	0.0132

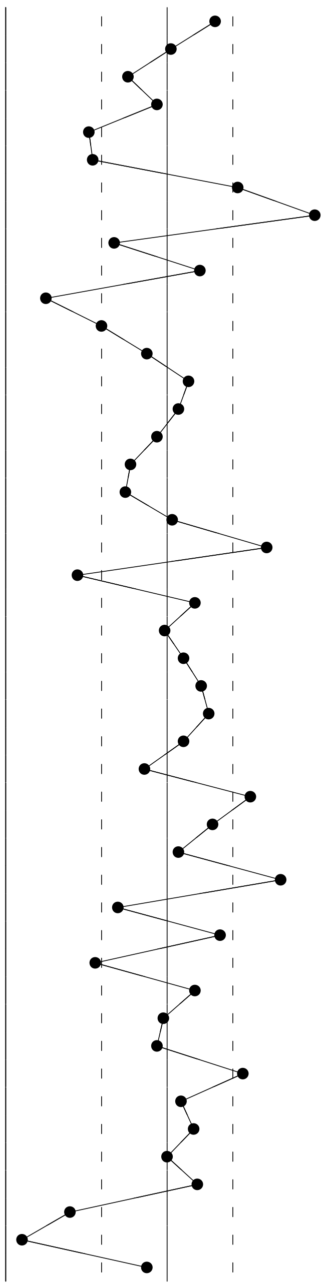
Test Equation:
Dependent Variable: LRESID2
Method: Least Squares
Date: 12/15/14 Time: 12:39
Sample: 2010M06 2014M03
Included observations: 46

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	18.01456	12.85899	1.400931	0.1688
HLF_PRICE	-1.282738	1.089944	-1.176885	0.2460
EDD_BC	0.001928	0.000785	2.455579	0.0184
D_2012M9	1.887539	1.570177	1.202119	0.2362
TREND	-0.100676	0.056120	-1.793933	0.0802

R-squared	0.201472	Mean dependent var	1.574025
Adjusted R-squared	0.123567	S.D. dependent var	2.621650
S.E. of regression	2.454336	Akaike info criterion	4.735912
Sum squared resid	246.9745	Schwarz criterion	4.934677
Log likelihood	-103.9260	Hannan-Quinn criter.	4.810371
F-statistic	2.586124	Durbin-Watson stat	2.176812
Prob(F-statistic)	0.050942		

obs	Actual	Fitted	Residual
2010M06	82.8465	79.1311	3.71543
2010M07	78.3562	78.0305	0.32571
2010M08	81.2139	84.2566	-3.04271
2010M09	83.1092	83.9215	-0.81225
2010M10	90.2793	96.4384	-6.15909
2010M11	101.815	107.636	-5.82119
2010M12	123.764	118.212	5.55194
2011M01	146.215	134.681	11.5344
2011M02	140.553	144.705	-4.15225
2011M03	134.736	132.123	2.61331
2011M04	117.520	126.996	-9.47589
2011M05	105.657	110.852	-5.19516
2011M06	96.9388	98.5063	-1.56741
2011M07	93.1796	91.4518	1.72777
2011M08	97.2976	96.4063	0.89136
2011M09	97.5756	98.3362	-0.76056
2011M10	106.666	109.567	-2.90082
2011M11	117.947	121.235	-3.28828
2011M12	128.511	128.124	0.38690
2012M01	146.582	138.780	7.80214
2012M02	136.605	143.667	-7.06272
2012M03	134.049	131.919	2.13035
2012M04	121.712	121.956	-0.24422
2012M05	117.387	116.072	1.31508
2012M06	109.435	106.797	2.63801
2012M07	103.639	100.404	3.23467
2012M08	105.990	104.693	1.29682
2012M09	120.588	122.386	-1.79812
2012M10	137.481	130.961	6.51990
2012M11	149.311	145.757	3.55449
2012M12	155.968	155.049	0.91826
2013M01	173.897	164.956	8.94129
2013M02	160.982	164.867	-3.88567
2013M03	158.246	154.091	4.15507
2013M04	141.238	146.859	-5.62055
2013M05	133.584	131.415	2.16851
2013M06	122.445	122.787	-0.34208
2013M07	112.973	113.753	-0.78023
2013M08	122.199	116.307	5.89218
2013M09	119.594	118.539	1.05575
2013M10	131.970	129.916	2.05408
2013M11	141.161	141.154	0.00687
2013M12	162.384	160.012	2.37287
2014M01	167.124	174.711	-7.58765
2014M02	153.413	164.818	-11.4053
2014M03	157.534	159.107	-1.57263

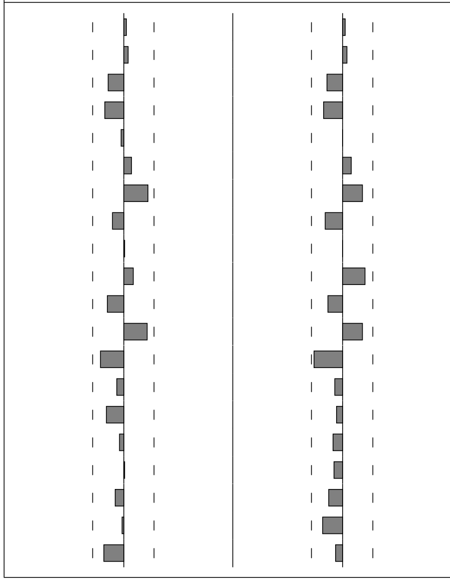
Residual Plot



Correlogram of Residuals

Date: 12/15/14 Time: 12:39
Sample: 2010M06 2014M03
Included observations: 46
Q-statistic probabilities adjusted for 3 ARMA term(s)

Autocorrelation | Partial Correlation



	AC	PAC	Q-Stat	Prob
1	0.030	0.030	0.0433	
2	0.043	0.042	0.1345	
3	-0.140	-0.143	1.1435	
4	-0.176	-0.173	2.7742	0.096
5	-0.018	0.003	2.7907	0.248
6	0.080	0.082	3.1435	0.370
7	0.232	0.194	6.1975	0.185
8	-0.102	-0.160	6.7988	0.236
9	0.009	0.002	6.8034	0.339
10	0.097	0.215	7.3751	0.391
11	-0.150	-0.132	8.8004	0.359
12	0.223	0.193	12.024	0.212
13	-0.214	-0.269	15.092	0.129
14	-0.059	-0.073	15.330	0.168
15	-0.160	-0.057	17.151	0.144
16	-0.034	-0.087	17.237	0.189
17	0.009	-0.079	17.244	0.243
18	-0.080	-0.125	17.746	0.276
19	-0.015	-0.183	17.765	0.338
20	-0.186	-0.062	20.691	0.240

Dependent Variable: M_LLF_C_S
Method: Least Squares
Date: 05/13/14 Time: 10:55
Sample (adjusted): 2011M12 2014M03
Included observations: 28 after adjustments
Convergence achieved after 11 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LN_TREND	581.8720	405.1305	1.436258	0.1702
EMPNM	116.1617	42.96106	2.703883	0.0156
C	-60228.67	22684.14	-2.655101	0.0173
SEP	145.5475	58.73609	2.477991	0.0247
OCT	383.2721	88.64099	4.323870	0.0005
NOV	458.8868	97.77718	4.693189	0.0002
DEC	476.0098	105.8766	4.495893	0.0004
JAN	475.9868	103.7797	4.586512	0.0003
FEB	387.2575	89.95897	4.304824	0.0005
MAR	321.0804	77.34588	4.151228	0.0008
APR	118.8395	55.65858	2.135152	0.0486
AR(1)	0.729094	0.070724	10.30899	0.0000

R-squared	0.990289	Mean dependent var	5491.464
Adjusted R-squared	0.983612	S.D. dependent var	578.3357
S.E. of regression	74.03557	Akaike info criterion	11.74450
Sum squared resid	87700.24	Schwarz criterion	12.31544
Log likelihood	-152.4229	Hannan-Quinn criter.	11.91904
F-statistic	148.3242	Durbin-Watson stat	1.703828
Prob(F-statistic)	0.000000		

Inverted AR Roots .73

Variable Name	Definition
LN_TREND	Logarithmic Trend
EMPNM	Non-Manufacturing Employment
C	Constant
SEP	September
OCT	October
NOV	November
DEC	December
JAN	January
FEB	February
MAR	March
APR	April
AR(1)	Autoregressive Term, lag 1

Heteroskedasticity Test: Harvey

F-statistic	2.034354	Prob. F(10,17)	0.0949
Obs*R-squared	15.25348	Prob. Chi-Square(10)	0.1231
Scaled explained SS	14.09815	Prob. Chi-Square(10)	0.1686

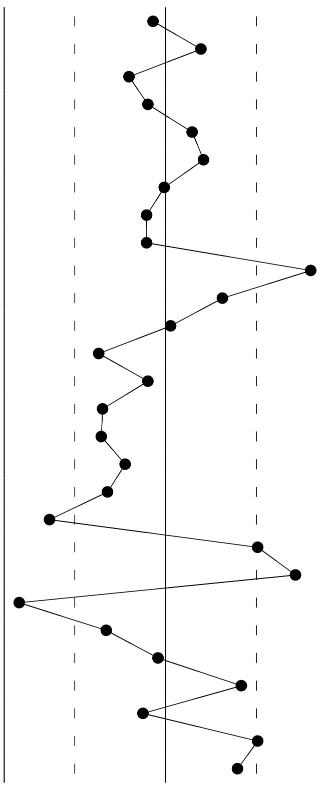
Test Equation:
Dependent Variable: LRESID2
Method: Least Squares
Date: 12/15/14 Time: 12:21
Sample: 2011M12 2014M03
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-32.43586	135.1306	-0.240033	0.8132
LN_TREND	1.099998	1.028113	1.069919	0.2996
EMPNM	0.065796	0.249928	0.263261	0.7955
SEP	2.768874	1.471448	1.881734	0.0771
OCT	0.865616	1.490165	0.580886	0.5689
NOV	-3.599293	1.486894	-2.420678	0.0270
DEC	0.842762	1.272888	0.662087	0.5168
JAN	-0.316358	1.257687	-0.251540	0.8044
FEB	1.267902	1.256971	1.008696	0.3273
MAR	0.496583	1.262582	0.393308	0.6990
APR	0.271936	1.470007	0.184989	0.8554

R-squared	0.544767	Mean dependent var	6.801593
Adjusted R-squared	0.276983	S.D. dependent var	2.174846
S.E. of regression	1.849280	Akaike info criterion	4.354193
Sum squared resid	58.13725	Schwarz criterion	4.877559
Log likelihood	-49.95871	Hannan-Quinn criter.	4.514192
F-statistic	2.034354	Durbin-Watson stat	1.881433
Prob(F-statistic)	0.094879		

obs	Actual	Fitted	Residual
2011M12	5038.00	5047.97	-9.96614
2012M01	5052.00	5023.01	28.9897
2012M02	4974.00	5003.97	-29.9732
2012M03	4949.00	4963.69	-14.6859
2012M04	4898.00	4876.65	21.3490
2012M05	4824.00	4792.76	31.2356
2012M06	4810.00	4811.03	-1.02746
2012M07	4800.00	4815.29	-15.2867
2012M08	4784.00	4798.95	-14.9526
2012M09	5068.00	4949.48	118.522
2012M10	5292.00	5245.59	46.4086
2012M11	5409.00	5404.76	4.24449
2012M12	5442.00	5496.53	-54.5280
2013M01	5491.00	5505.74	-14.7368
2013M02	5476.00	5526.92	-50.9228
2013M03	5495.00	5547.57	-52.5719
2013M04	5430.00	5462.96	-32.9577
2013M05	5384.00	5431.16	-47.1577
2013M06	5397.00	5491.56	-94.5629
2013M07	5615.00	5539.77	75.2262
2013M08	5788.00	5682.04	105.955
2013M09	5847.00	5966.79	-119.793
2013M10	6086.00	6134.15	-48.1523
2013M11	6257.00	6263.64	-6.63614
2013M12	6442.00	6380.79	61.2138
2014M01	6506.00	6524.75	-18.7520
2014M02	6579.00	6504.27	74.7251
2014M03	6628.00	6569.21	58.7940

Residual Plot



Correlogram of Residuals

Date: 12/15/14 Time: 12:20
Sample: 2011M12 2014M03
Included observations: 28
Q-statistic probabilities adjusted for 1 ARMA term(s)

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	0.128	0.128	0.5082	
		2	-0.248	-0.268	2.4893	0.115
		3	-0.026	0.053	2.5121	0.285
		4	0.171	0.110	3.5371	0.316
		5	-0.125	-0.186	4.1120	0.391
		6	-0.080	0.050	4.3549	0.500
		7	0.033	-0.036	4.3980	0.623
		8	-0.146	-0.215	5.2914	0.624
		9	-0.127	-0.009	6.0092	0.646
		10	0.110	0.046	6.5722	0.682
		11	-0.010	-0.130	6.5771	0.765
		12	-0.329	-0.256	12.246	0.345

Dependent Variable: M_LLF_UPC_S
Method: Least Squares
Date: 05/06/14 Time: 10:30
Sample (adjusted): 2010M04 2014M03
Included observations: 48 after adjustments
Convergence achieved after 15 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_BC	0.032412	0.001507	21.50958	0.0000
C	2.523259	0.693799	3.636873	0.0008
DEC	7.461469	1.706068	4.373489	0.0001
JAN	17.71654	1.890468	9.371507	0.0000
FEB	18.38456	2.007228	9.159179	0.0000
MAR	11.76262	1.613877	7.288422	0.0000
LLF_PRICE*(NOV+DEC+JAN+FEB+MA	-0.167715	0.102987	-1.628512	0.1113
AR(4)	0.287178	0.148612	1.932398	0.0604

R-squared	0.988424	Mean dependent var	25.47730
Adjusted R-squared	0.986399	S.D. dependent var	20.90554
S.E. of regression	2.438110	Akaike info criterion	4.771335
Sum squared resid	237.7752	Schwarz criterion	5.083202
Log likelihood	-106.5120	Hannan-Quinn criter.	4.889190
F-statistic	487.9322	Durbin-Watson stat	1.842129
Prob(F-statistic)	0.000000		

Inverted AR Roots	.73	.00-.73i	-.00+.73i	-.73

Variable Name	Definition
EDD_BC	Bill Cycle EDD
C	Constant
DEC	December
JAN	January
FEB	February
MAR	March
LLF_PRICE*(NOV+DEC+JAN+FEB+MAR)	Interaction Variable - LLF Natural Gas Price * Winter Months
AR(4)	Autoregressive Term, lag 4

Heteroskedasticity Test: Breusch-Pagan-Godfrey

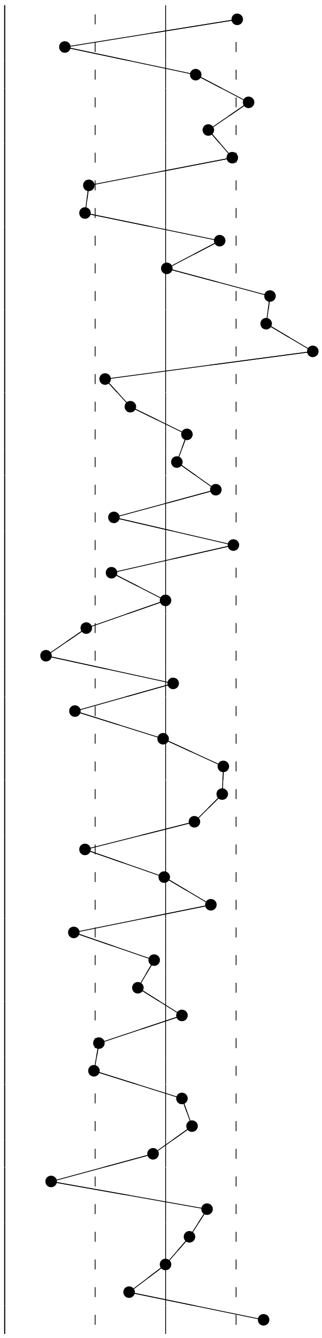
F-statistic	2.057675	Prob. F(6,41)	0.0796
Obs*R-squared	11.10880	Prob. Chi-Square(6)	0.0851
Scaled explained SS	4.725568	Prob. Chi-Square(6)	0.5795

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 12/15/14 Time: 12:35
Sample: 2010M04 2014M03
Included observations: 48

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2.640399	1.365363	1.933843	0.0601
EDD_BC	0.008623	0.003580	2.408715	0.0206
DEC	-3.893741	3.838999	-1.014259	0.3164
JAN	-6.560817	4.290420	-1.529178	0.1339
FEB	-3.682266	4.329012	-0.850602	0.3999
MAR	2.930897	3.991019	0.734373	0.4669
LLF_PRICE*(NOV+DEC+JAN+FEB+MA	-0.328911	0.222311	-1.479505	0.1466

R-squared	0.231433	Mean dependent var	4.953651
Adjusted R-squared	0.118960	S.D. dependent var	5.540983
S.E. of regression	5.200973	Akaike info criterion	6.269606
Sum squared resid	1109.055	Schwarz criterion	6.542490
Log likelihood	-143.4705	Hannan-Quinn criter.	6.372729
F-statistic	2.057675	Durbin-Watson stat	2.095109
Prob(F-statistic)	0.079561		

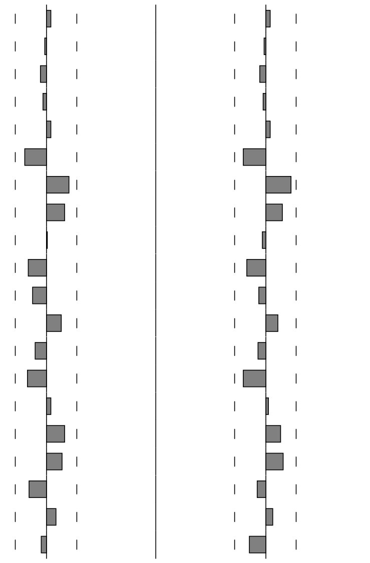
obs	Actual	Fitted	Residual	Residual Plot
2010M04	27.0509	24.5804	2.47059	
2010M05	14.0762	17.5865	-3.51028	
2010M06	7.14246	6.11038	1.03209	
2010M07	6.03272	3.15656	2.87615	
2010M08	5.11541	3.65106	1.46435	
2010M09	5.93453	3.60297	2.33156	
2010M10	9.25543	11.9261	-2.67069	
2010M11	20.4919	23.2918	-2.79991	
2010M12	42.8296	40.9351	1.89449	
2011M01	60.2728	60.2405	0.03237	
2011M02	66.8330	63.2098	3.62319	
2011M03	51.0580	47.5595	3.49845	
2011M04	36.9781	31.8872	5.09084	
2011M05	16.9903	19.1049	-2.11459	
2011M06	9.51374	10.7447	-1.23095	
2011M07	5.88427	5.13899	0.74528	
2011M08	4.68359	4.29627	0.38732	
2011M09	5.52986	3.77383	1.75604	
2011M10	8.09546	9.88635	-1.79089	
2011M11	22.7661	20.3895	2.37661	
2011M12	32.2229	34.1118	-1.88882	
2012M01	56.5080	56.5079	5.5E-05	
2012M02	53.0578	55.8249	-2.76711	
2012M03	40.1482	44.3129	-4.16467	
2012M04	24.5469	24.2882	0.25875	
2012M05	14.5995	17.7578	-3.15826	
2012M06	7.69352	7.79372	-0.10020	
2012M07	4.72972	2.72746	2.00226	
2012M08	4.44159	2.49066	1.95094	
2012M09	4.34800	3.32991	1.01809	
2012M10	8.84995	11.6527	-2.80277	
2012M11	22.5238	22.5575	-0.03366	
2012M12	41.0659	39.5094	1.55653	
2013M01	53.9969	57.2030	-3.20612	
2013M02	58.6691	59.0605	-0.39142	
2013M03	44.6573	45.6079	-0.95057	
2013M04	31.8734	31.3266	0.54672	
2013M05	16.1362	18.4357	-2.29945	
2013M06	7.00582	9.51222	-2.50639	
2013M07	4.43328	3.86029	0.57298	
2013M08	4.37790	3.46989	0.90801	
2013M09	3.80425	4.22714	-0.42289	
2013M10	7.51468	11.4860	-3.97130	
2013M11	23.1591	21.7294	1.42972	
2013M12	45.2260	44.3860	0.84004	
2014M01	63.9878	63.9960	-0.00825	
2014M02	59.8510	61.1212	-1.27013	
2014M03	56.9471	53.5512	3.39593	



Correlogram of Residuals

Date: 12/15/14 Time: 12:34
Sample: 2010M04 2014M03
Included observations: 48
Q-statistic probabilities adjusted for 1 ARMA term(s)

Autocorrelation | Partial Correlation



	AC	PAC	Q-Stat	Prob
1	0.042	0.042	0.0894	
2	-0.013	-0.015	0.0982	0.754
3	-0.053	-0.052	0.2489	0.883
4	-0.026	-0.022	0.2871	0.962
5	0.046	0.047	0.4054	0.982
6	-0.200	-0.209	2.6904	0.748
7	0.214	0.244	5.3676	0.498
8	0.177	0.158	7.2456	0.404
9	0.010	-0.032	7.2519	0.510
10	-0.167	-0.172	9.0150	0.436
11	-0.128	-0.065	10.070	0.434
12	0.145	0.121	11.475	0.404
13	-0.102	-0.066	12.190	0.431
14	-0.176	-0.205	14.369	0.348
15	0.048	0.028	14.539	0.410
16	0.173	0.145	16.784	0.332
17	0.148	0.168	18.480	0.297
18	-0.157	-0.079	20.445	0.252
19	0.096	0.071	21.211	0.269
20	-0.048	-0.149	21.408	0.315

Dependent Variable: M_HLF_C_S
Method: Least Squares
Date: 05/09/14 Time: 12:01
Sample (adjusted): 2009M04 2014M03
Included observations: 60 after adjustments
Failure to improve SSR after 11 iterations
MA Backcast: 2008M12 2009M03

Variable	Coefficient	Std. Error	t-Statistic	Prob.
D_2012M9_	-486.3858	14.62045	-33.26749	0.0000
D_2013M7_	92.65070	6.988349	13.25788	0.0000
EMPM	17.95455	11.30364	1.588387	0.1188
C	734.9372	575.7506	1.276486	0.2079
D_2012M9	-38.98936	8.456484	-4.610587	0.0000
D_2012M10	-24.40723	7.467479	-3.268470	0.0020
D_2013M8	-14.63060	5.845616	-2.502832	0.0158
D_2009M1_2012M8*TREN	-6.998685	0.394119	-17.75779	0.0000
AR(3)	0.407411	0.135065	3.016396	0.0041
MA(1)	0.727747	0.124592	5.841027	0.0000
MA(2)	0.727718	0.130897	5.559472	0.0000
MA(4)	-0.377358	0.111053	-3.398006	0.0014

R-squared	0.997707	Mean dependent var	1389.917
Adjusted R-squared	0.997182	S.D. dependent var	155.7682
S.E. of regression	8.269227	Akaike info criterion	7.239816
Sum squared resid	3282.245	Schwarz criterion	7.658684
Log likelihood	-205.1945	Hannan-Quinn criter.	7.403658
F-statistic	1898.849	Durbin-Watson stat	1.860616
Prob(F-statistic)	0.000000		

Inverted AR Roots	.74	-.37+.64i	-.37-.64i	
Inverted MA Roots	.52	-.26-.96i	-.26+.96i	-.72

Variable Name	Definition
D_2012M9	Dummy, September 2012
D_2013M7	Dummy, July 2013
EMPM	Manufacturing Employment
C	Constant
D_2012M9	Dummy, September 2012
D_2012M10	Dummy, October 2012
D_2013M8	Dummy, August 2013
D_2009M1_2012M8*TREND	Interaction Variable - Linear Trend * Dummy, January 2009 - August 2012
AR(3)	Autoregressive Term, lag 3
MA(1)	Moving Average Term, lag 1
MA(2)	Moving Average Term, lag 2
MA(4)	Moving Average Term, lag 4

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	1.061367	Prob. F(7,52)	0.4013
Obs*R-squared	7.500878	Prob. Chi-Square(7)	0.3787
Scaled explained SS	4.555436	Prob. Chi-Square(7)	0.7140

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 12/15/14   Time: 12:27
Sample: 2009M04 2014M03
Included observations: 60

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1516.736	1430.434	1.060333	0.2939
D_2012M9_	-99.76615	50.99230	-1.956494	0.0558
D_2013M7_	13.40163	39.17120	0.342130	0.7336
EMPM	-27.66613	27.71577	-0.998209	0.3228
D_2012M9	-11.24774	81.18286	-0.138548	0.8903
D_2012M10	-11.34221	81.01335	-0.140004	0.8892
D_2013M8	102.2530	80.38718	1.272007	0.2090
D_2009M1_2012M8*TREN	-1.644782	1.233575	-1.333346	0.1882

R-squared	0.125015	Mean dependent var	54.70409
Adjusted R-squared	0.007228	S.D. dependent var	75.99821
S.E. of regression	75.72305	Akaike info criterion	11.61561
Sum squared resid	298167.0	Schwarz criterion	11.89485
Log likelihood	-340.4682	Hannan-Quinn criter.	11.72484
F-statistic	1.061367	Durbin-Watson stat	1.832839
Prob(F-statistic)	0.401313		

obs	Actual	Fitted	Residual	Residual Plot
2009M04	1650.00	1647.03	2.97071	
2009M05	1623.00	1621.66	1.34372	
2009M06	1614.00	1620.93	-6.92721	
2009M07	1632.00	1616.38	15.6161	
2009M08	1615.00	1602.58	12.4249	
2009M09	1616.00	1608.64	7.35662	
2009M10	1608.00	1607.68	0.31630	
2009M11	1574.00	1578.97	-4.97039	
2009M12	1552.00	1567.32	-15.3217	
2010M01	1553.00	1550.25	2.75153	
2010M02	1551.00	1540.43	10.5694	
2010M03	1536.00	1547.95	-11.9534	
2010M04	1533.00	1537.48	-4.48083	
2010M05	1509.00	1514.16	-5.15633	
2010M06	1504.00	1505.33	-1.32634	
2010M07	1504.00	1509.35	-5.34507	
2010M08	1496.00	1492.77	3.22675	
2010M09	1488.00	1491.23	-3.22516	
2010M10	1504.00	1487.07	16.9289	
2010M11	1478.00	1493.95	-15.9525	
2010M12	1474.00	1476.42	-2.42250	
2011M01	1464.00	1473.18	-9.17956	
2011M02	1456.00	1453.32	2.67883	
2011M03	1450.00	1459.72	-9.72492	
2011M04	1431.00	1440.58	-9.58085	
2011M05	1432.00	1425.27	6.73004	
2011M06	1428.00	1426.23	1.76762	
2011M07	1425.00	1426.21	-1.20839	
2011M08	1418.00	1417.53	0.47140	
2011M09	1405.00	1405.52	-0.52429	
2011M10	1418.00	1403.32	14.6797	
2011M11	1416.00	1408.75	7.25293	
2011M12	1417.00	1405.36	11.6362	
2012M01	1414.00	1405.75	8.25337	
2012M02	1383.00	1396.89	-13.8904	
2012M03	1373.00	1378.20	-5.20433	
2012M04	1367.00	1363.46	3.54229	
2012M05	1361.00	1359.96	1.03803	
2012M06	1359.00	1363.40	-4.40427	
2012M07	1347.00	1346.65	0.35415	
2012M08	1339.00	1335.13	3.86721	
2012M09	1125.00	1125.64	-0.64034	
2012M10	1140.00	1138.76	1.24056	
2012M11	1163.00	1157.42	5.58008	
2012M12	1161.00	1160.42	0.58041	
2013M01	1162.00	1158.91	3.09006	
2013M02	1156.00	1155.73	0.26511	
2013M03	1151.00	1153.91	-2.91160	
2013M04	1152.00	1151.57	0.43193	
2013M05	1139.00	1150.51	-11.5093	
2013M06	1143.00	1145.35	-2.34648	
2013M07	1239.00	1241.38	-2.37817	
2013M08	1215.00	1226.51	-11.5091	
2013M09	1233.00	1239.69	-6.68588	
2013M10	1231.00	1232.24	-1.24390	
2013M11	1237.00	1236.96	0.03944	
2013M12	1248.00	1248.59	-0.59308	
2014M01	1260.00	1248.48	11.5170	
2014M02	1256.00	1258.52	-2.51585	
2014M03	1267.00	1262.15	4.84784	

Correlogram of Residuals

Date: 12/15/14 Time: 12:27
Sample: 2009M04 2014M03
Included observations: 60
Q-statistic probabilities adjusted for 4 ARMA term(s)

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	0.064	0.064	0.2576	
		2	0.045	0.041	0.3894	
		3	-0.037	-0.043	0.4811	
		4	0.022	0.026	0.5147	
		5	-0.091	-0.092	1.0807	0.299
		6	-0.023	-0.015	1.1182	0.572
		7	-0.085	-0.073	1.6206	0.655
		8	-0.091	-0.089	2.2172	0.696
		9	-0.167	-0.151	4.2481	0.514
		10	-0.114	-0.111	5.2159	0.516
		11	-0.016	-0.006	5.2347	0.631
		12	0.082	0.067	5.7499	0.675
		13	0.086	0.064	6.3350	0.706
		14	0.061	0.022	6.6352	0.759
		15	0.225	0.203	10.821	0.458
		16	-0.176	-0.246	13.455	0.337
		17	-0.105	-0.147	14.415	0.345
		18	-0.070	-0.083	14.850	0.389
		19	-0.187	-0.278	18.037	0.261
		20	-0.166	-0.151	20.593	0.195
		21	-0.081	-0.089	21.223	0.216
		22	-0.071	-0.048	21.722	0.245
		23	-0.067	-0.046	22.177	0.276
		24	-0.120	-0.157	23.666	0.257
		25	0.008	-0.112	23.672	0.309
		26	0.183	0.023	27.349	0.198
		27	0.247	0.066	34.212	0.062
		28	0.096	-0.068	35.273	0.064

Dependent Variable: M_HLF_UPC_S
Method: Least Squares
Date: 05/06/14 Time: 10:35
Sample (adjusted): 2010M01 2014M03
Included observations: 51 after adjustments
Convergence achieved after 23 iterations
MA Backcast: 2009M10 2009M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
HLF_PRICE*(NOV+DEC+JAN+FEB+MA	-0.100401	0.029113	-3.448624	0.0012
EDD_BC	0.018697	0.001335	14.00938	0.0000
C	13.50988	1.320818	10.22842	0.0000
AR(1)	0.887223	0.094366	9.401906	0.0000
MA(3)	-0.925979	0.025882	-35.77680	0.0000

R-squared	0.946088	Mean dependent var	23.83304
Adjusted R-squared	0.941400	S.D. dependent var	8.779521
S.E. of regression	2.125300	Akaike info criterion	4.438597
Sum squared resid	207.7774	Schwarz criterion	4.627992
Log likelihood	-108.1842	Hannan-Quinn criter.	4.510970
F-statistic	201.8100	Durbin-Watson stat	2.066499
Prob(F-statistic)	0.000000		

Inverted AR Roots	.89		
Inverted MA Roots	.97	-.49-.84i	-.49+.84i

Variable Name	Definition
HLF_PRICE*(NOV+DEC+JAN+FEB+MAR)	Interaction Variable - HLF Natural Gas Price * November - March
EDD_BC	Bill Cycle EDD
C	Constant
AR(1)	Autoregressive Term, lag 1
MA(3)	Moving Average Term, lag 3

Heteroskedasticity Test: Breusch-Pagan-Godfrey

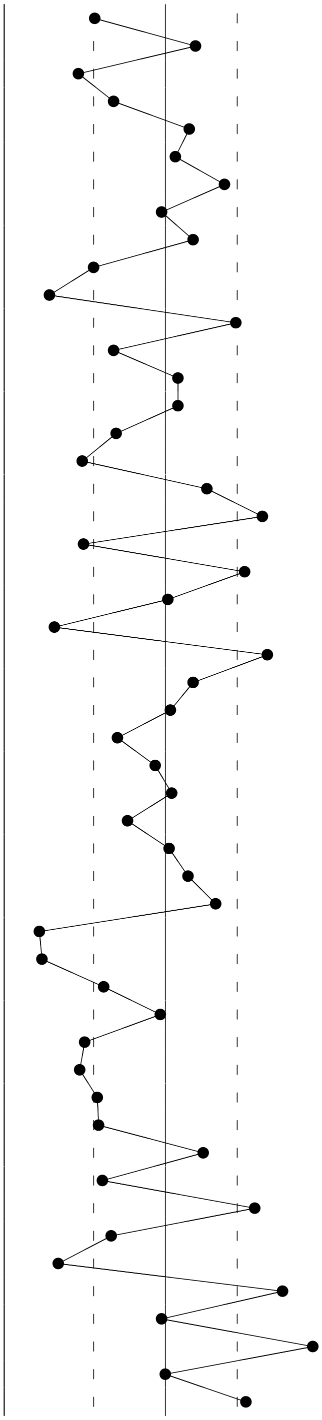
F-statistic	2.901990	Prob. F(2,48)	0.0646
Obs*R-squared	5.501507	Prob. Chi-Square(2)	0.0639
Scaled explained SS	2.559736	Prob. Chi-Square(2)	0.2781

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 12/15/14 Time: 12:38
Sample: 2010M01 2014M03
Included observations: 51

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4.379390	1.013286	4.321968	0.0001
HLF_PRICE*(NOV+DEC+JAN+FEB+MA	0.475747	0.199575	2.383797	0.0211
EDD_BC	-0.004331	0.002356	-1.838406	0.0722

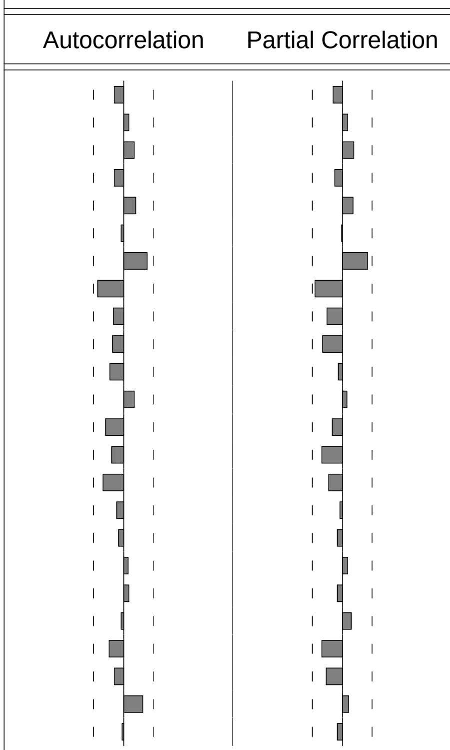
R-squared	0.107873	Mean dependent var	4.074067
Adjusted R-squared	0.070701	S.D. dependent var	4.400605
S.E. of regression	4.242190	Akaike info criterion	5.785059
Sum squared resid	863.8165	Schwarz criterion	5.898696
Log likelihood	-144.5190	Hannan-Quinn criter.	5.828483
F-statistic	2.901990	Durbin-Watson stat	1.976414
Prob(F-statistic)	0.064602		

obs	Actual	Fitted	Residual	Residual Plot
2010M01	30.3080	32.4050	-2.09702	
2010M02	24.9317	24.0217	0.91007	
2010M03	23.2147	25.7676	-2.55295	
2010M04	20.6960	22.2043	-1.50828	
2010M05	16.8696	16.1569	0.71269	
2010M06	15.2655	14.9831	0.28244	
2010M07	15.9689	14.2237	1.74511	
2010M08	14.5117	14.6108	-0.09911	
2010M09	15.8808	15.0452	0.83562	
2010M10	16.5864	18.6900	-2.10361	
2010M11	19.6744	23.0896	-3.41528	
2010M12	27.4893	25.4242	2.06503	
2011M01	33.6750	35.2067	-1.53169	
2011M02	39.6485	39.2622	0.38633	
2011M03	32.6704	32.2806	0.38986	
2011M04	29.4592	30.9271	-1.46794	
2011M05	19.6743	22.1346	-2.46031	
2011M06	15.7298	14.4894	1.24042	
2011M07	16.9207	14.0683	2.85237	
2011M08	15.5269	17.9579	-2.43103	
2011M09	17.4807	15.1481	2.33264	
2011M10	17.8466	17.7817	0.06485	
2011M11	22.8023	26.0669	-3.26456	
2011M12	27.2815	24.2850	2.99649	
2012M01	35.1594	34.3543	0.80507	
2012M02	38.0142	37.8791	0.13511	
2012M03	29.8098	31.2099	-1.40015	
2012M04	24.5194	24.8064	-0.28706	
2012M05	20.7585	20.5543	0.20428	
2012M06	15.9801	17.0806	-1.10051	
2012M07	13.5578	13.4554	0.10239	
2012M08	13.4430	12.7661	0.67695	
2012M09	16.9133	15.4419	1.47140	
2012M10	17.2843	21.0129	-3.72853	
2012M11	19.4335	23.0690	-3.63548	
2012M12	22.2409	24.0557	-1.81475	
2013M01	31.1054	31.2492	-0.14380	
2013M02	33.7447	36.1109	-2.36615	
2013M03	28.6913	31.2210	-2.52973	
2013M04	25.1377	27.1293	-1.99160	
2013M05	19.3284	21.2892	-1.96084	
2013M06	17.7569	16.6495	1.10741	
2013M07	14.3989	16.2727	-1.87379	
2013M08	18.3070	15.6568	2.65022	
2013M09	16.3507	17.9398	-1.58911	
2013M10	18.8994	22.0682	-3.16888	
2013M11	25.5669	22.1084	3.45847	
2013M12	35.4200	35.5406	-0.12059	
2014M01	48.2399	43.9101	4.32981	
2014M02	42.4913	42.5028	-0.01147	
2014M03	42.8195	40.4417	2.37773	



Correlogram of Residuals

Date: 12/15/14 Time: 12:37
Sample: 2010M01 2014M03
Included observations: 51
Q-statistic probabilities adjusted for 2 ARMA term(s)



	AC	PAC	Q-Stat	Prob
1	-0.086	-0.086	0.4032	
2	0.057	0.050	0.5830	
3	0.100	0.110	1.1486	0.284
4	-0.083	-0.070	1.5485	0.461
5	0.121	0.099	2.4071	0.492
6	-0.023	-0.008	2.4382	0.656
7	0.229	0.238	5.6580	0.341
8	-0.243	-0.260	9.3839	0.153
9	-0.098	-0.140	10.006	0.188
10	-0.099	-0.181	10.652	0.222
11	-0.125	-0.035	11.703	0.231
12	0.104	0.049	12.453	0.256
13	-0.166	-0.097	14.413	0.211
14	-0.107	-0.191	15.252	0.228
15	-0.194	-0.129	18.064	0.155
16	-0.064	-0.022	18.380	0.190
17	-0.042	-0.044	18.523	0.236
18	0.049	0.050	18.718	0.284
19	0.054	-0.043	18.965	0.331
20	-0.022	0.084	19.006	0.391
21	-0.134	-0.189	20.627	0.358
22	-0.086	-0.148	21.323	0.378
23	0.185	0.059	24.628	0.264
24	-0.011	-0.046	24.641	0.315

Dependent Variable: PERCENT_EXEMPT
Method: Least Squares
Date: 05/16/14 Time: 12:14
Sample (adjusted): 2010M11 2014M03
Included observations: 41 after adjustments
Convergence achieved after 7 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
NOV	-0.028700	0.004772	-6.014043	0.0000
MAR	-0.033917	0.006174	-5.493307	0.0000
JAN	-0.049776	0.006380	-7.802388	0.0000
FEB	-0.043802	0.006452	-6.789176	0.0000
DEC	-0.043399	0.005919	-7.332344	0.0000
APR	-0.022813	0.005288	-4.313712	0.0001
C	0.140868	0.016382	8.598778	0.0000
TREND	0.001361	0.000351	3.881643	0.0005
AR(1)	0.652555	0.138783	4.701984	0.0000

R-squared	0.929055	Mean dependent var	0.178266
Adjusted R-squared	0.911319	S.D. dependent var	0.030182
S.E. of regression	0.008988	Akaike info criterion	-6.394643
Sum squared resid	0.002585	Schwarz criterion	-6.018493
Log likelihood	140.0902	Hannan-Quinn criter.	-6.257670
F-statistic	52.38178	Durbin-Watson stat	1.998536
Prob(F-statistic)	0.000000		

Inverted AR Roots .65

Variable Name	Definition
NOV	November
MAR	March
JAN	January
FEB	February
DEC	December
APR	April
C	Constant
TREND	Linear Trend
AR(1)	Autoregressive Term, lag 1

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	1.751855	Prob. F(7,33)	0.1310
Obs*R-squared	11.10803	Prob. Chi-Square(7)	0.1340
Scaled explained SS	9.475099	Prob. Chi-Square(7)	0.2203

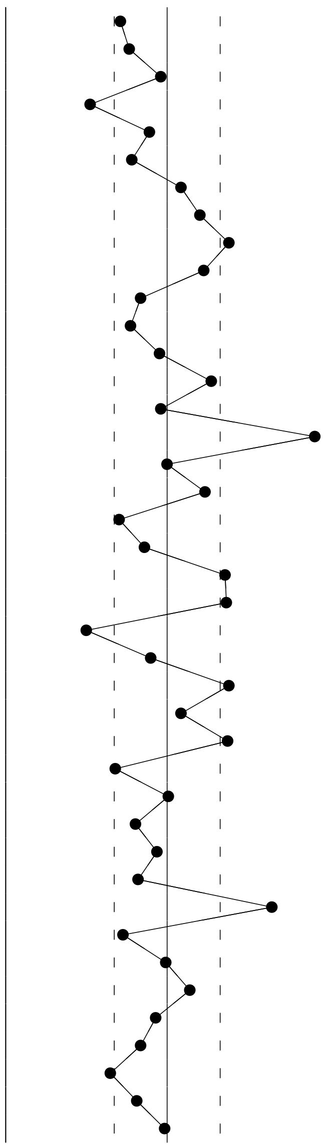
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 12/15/14 Time: 12:40
Sample: 2010M11 2014M03
Included observations: 41

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	8.32E-05	6.27E-05	1.327001	0.1936
NOV	-1.93E-05	5.56E-05	-0.347363	0.7305
MAR	-5.84E-05	5.55E-05	-1.051574	0.3006
JAN	-1.21E-05	5.55E-05	-0.218238	0.8286
FEB	0.000158	5.55E-05	2.854880	0.0074
DEC	-3.28E-05	5.55E-05	-0.590241	0.5590
APR	-2.90E-05	6.28E-05	-0.462077	0.6471
TREND	-5.00E-07	1.33E-06	-0.374499	0.7104

R-squared	0.270927	Mean dependent var	6.31E-05
Adjusted R-squared	0.116276	S.D. dependent var	0.000107
S.E. of regression	0.000100	Akaike info criterion	-15.40113
Sum squared resid	3.33E-07	Schwarz criterion	-15.06678
Log likelihood	323.7232	Hannan-Quinn criter.	-15.27938
F-statistic	1.751855	Durbin-Watson stat	2.281076
Prob(F-statistic)	0.130963		

obs	Actual	Fitted	Residual
2010M11	0.13030	0.13806	-0.00776
2010M12	0.11528	0.12153	-0.00625
2011M01	0.11442	0.11542	-0.00100
2011M02	0.11247	0.12547	-0.01300
2011M03	0.12769	0.13066	-0.00296
2011M04	0.13979	0.14572	-0.00593
2011M05	0.17200	0.16965	0.00235
2011M06	0.18182	0.17626	0.00556
2011M07	0.19349	0.18314	0.01036
2011M08	0.19735	0.19123	0.00612
2011M09	0.18975	0.19422	-0.00447
2011M10	0.18365	0.18973	-0.00608
2011M11	0.15621	0.15752	-0.00131
2011M12	0.15146	0.14412	0.00734
2012M01	0.14365	0.14471	-0.00106
2012M02	0.17489	0.15022	0.02467
2012M03	0.17707	0.17706	1.1E-05
2012M04	0.18994	0.18361	0.00633
2012M05	0.19993	0.20805	-0.00813
2012M06	0.19638	0.20015	-0.00377
2012M07	0.20800	0.19831	0.00969
2012M08	0.21634	0.20637	0.00998
2012M09	0.19880	0.21229	-0.01349
2012M10	0.19855	0.20131	-0.00275
2012M11	0.18331	0.17292	0.01039
2012M12	0.16985	0.16748	0.00238
2013M01	0.17264	0.16238	0.01026
2013M02	0.16608	0.17481	-0.00873
2013M03	0.17725	0.17699	0.00026
2013M04	0.18419	0.18940	-0.00522
2013M05	0.20836	0.20997	-0.00161
2013M06	0.20655	0.21133	-0.00479
2013M07	0.22818	0.21062	0.01756
2013M08	0.21775	0.22521	-0.00746
2013M09	0.21872	0.21887	-0.00016
2013M10	0.22384	0.21998	0.00386
2013M11	0.19320	0.19509	-0.00189
2013M12	0.17526	0.17961	-0.00434
2014M01	0.16205	0.17159	-0.00953
2014M02	0.16858	0.17357	-0.00499
2014M03	0.18384	0.18429	-0.00045

Residual Plot



Correlogram of Residuals

Date: 12/15/14 Time: 12:40
Sample: 2010M11 2014M03
Included observations: 41
Q-statistic probabilities adjusted for 1 ARMA term(s)

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	-0.011	-0.011	0.0053	
		2	0.047	0.047	0.1042	0.747
		3	-0.168	-0.168	1.4179	0.492
		4	-0.024	-0.029	1.4446	0.695
		5	-0.043	-0.029	1.5368	0.820
		6	0.103	0.080	2.0752	0.839
		7	-0.044	-0.050	2.1739	0.903
		8	0.115	0.098	2.8835	0.896
		9	0.112	0.150	3.5695	0.894
		10	-0.218	-0.253	6.2599	0.714
		11	0.271	0.346	10.588	0.390
		12	-0.161	-0.184	12.162	0.352
		13	-0.084	-0.170	12.603	0.399
		14	-0.276	-0.202	17.578	0.174
		15	-0.010	-0.057	17.584	0.226
		16	-0.049	-0.014	17.755	0.276
		17	0.172	-0.059	19.936	0.223
		18	-0.074	0.045	20.354	0.257
		19	0.090	0.061	21.007	0.279
		20	-0.027	-0.076	21.066	0.333

Dependent Variable: ME
Method: Least Squares
Date: 05/15/14 Time: 14:34
Sample (adjusted): 11/09/2012 3/31/2014
Included observations: 508 after adjustments
Convergence achieved after 17 iterations
MA Backcast: 11/08/2012

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_ME	637.1241	11.70988	54.40913	0
EDD_15	76.12036	34.58102	2.201218	0.0282
WEEKDAY_1	9663.692	732.5457	13.19193	0
WEEKDAY_2	10535.99	727.8417	14.47566	0
WEEKDAY_3	10840.87	728.3916	14.88329	0
WEEKDAY_5	11093.61	729.2956	15.21141	0
WEEKDAY_4	10915.06	730.5421	14.94104	0
WEEKDAY_6	9442.275	728.6022	12.95944	0
WEEKDAY_7	8295.054	727.4212	11.40337	0
NOV	1659.956	909.8922	1.824344	0.0687
DEC	2444.625	931.9801	2.623044	0.009
JAN	3302.521	964.9203	3.422584	0.0007
FEB	2304.24	979.2884	2.352974	0.019
MAR	1429.889	907.2253	1.576112	0.1156
EDD_ME(-1)	160.884	10.10288	15.92456	0
AR(1)	0.733215	0.045697	16.04526	0
AR(7)	0.161385	0.035538	4.541232	0
MA(1)	-0.200691	0.066579	-3.014342	0.0027

R-squared	0.991798	Mean dependent var	32024.5
Adjusted R-squared	0.991514	S.D. dependent var	16142.12
S.E. of regression	1487.032	Akaike info criterion	17.48174
Sum squared resid	1.08E+09	Schwarz criterion	17.63164
Log likelihood	-4422.362	Hannan-Quinn criter.	17.54052
Durbin-Watson stat	1.953338		

Inverted AR Roots	0.95	.60+.55i	.60-.55i	-.09-.72i
	-.09+.72i	-.62-.33i	-.62+.33i	
Inverted MA Roots	0.2			

New Hampshire Division Statistical Model Results

Dependent Variable: N_RH_C
Method: Least Squares
Date: 05/16/14 Time: 09:36
Sample (adjusted): 2009M02 2014M03
Included observations: 62 after adjustments
Convergence achieved after 7 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
POP	14.76601	0.159881	92.35624	0.0000
TREND	36.29945	4.582869	7.920682	0.0000
OCT	115.7303	25.22251	4.588374	0.0000
NOV	164.1963	33.52482	4.897752	0.0000
DEC	217.1606	38.33021	5.665520	0.0000
JAN	233.2379	40.96825	5.693139	0.0000
FEB	222.6166	41.04817	5.423302	0.0000
MAR	205.0986	40.15635	5.107501	0.0000
APR	199.9819	37.78636	5.292437	0.0000
MAY	148.2321	33.21575	4.462706	0.0000
JUN	73.60787	25.10578	2.931909	0.0051
AR(1)	0.894472	0.065111	13.73760	0.0000

R-squared	0.993964	Mean dependent var	20831.84
Adjusted R-squared	0.992636	S.D. dependent var	658.2905
S.E. of regression	56.49219	Akaike info criterion	11.07807
Sum squared resid	159568.4	Schwarz criterion	11.48977
Log likelihood	-331.4201	Hannan-Quinn criter.	11.23971
Durbin-Watson stat	2.145174		
Inverted AR Roots	.89		

Variable Name	Definition
POP	Population
TREND	Linear Trend
OCT	October
NOV	November
DEC	December
JAN	January
FEB	February
MAR	March
APR	April
MAY	May
JUN	June
AR(1)	Autoregressive Term, lag 1

Heteroskedasticity Test: Breusch-Pagan-Godfrey

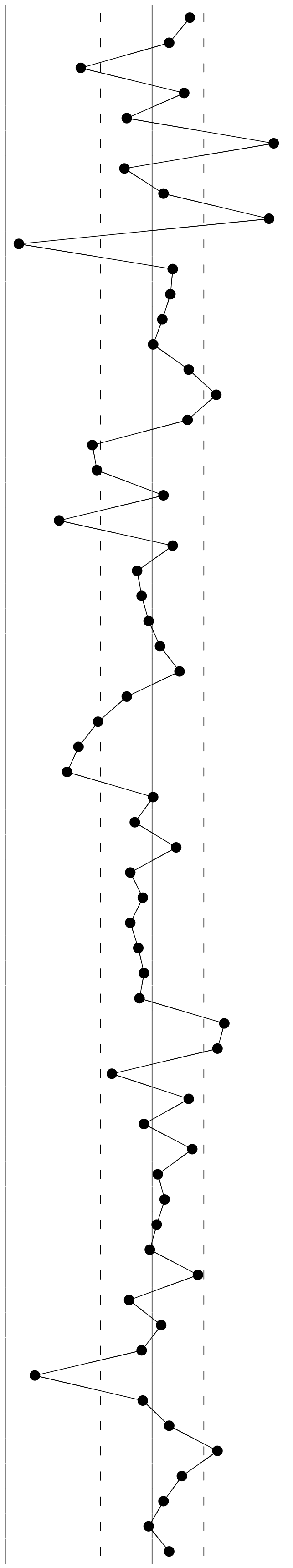
F-statistic	1.694491	Prob. F(11,50)	0.1020
Obs*R-squared	16.83643	Prob. Chi-Square(11)	0.1128
Scaled explained SS	17.18413	Prob. Chi-Square(11)	0.1025

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 14:14
Sample: 2009M02 2014M03
Included observations: 62

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-1243758.	1128853.	-1.101789	0.2758
POP	951.2292	859.0577	1.107294	0.2735
TREND	-223.7846	153.6248	-1.456696	0.1515
OCT	1185.922	2238.702	0.529736	0.5986
NOV	1639.969	2239.759	0.732208	0.4675
DEC	-3683.652	2241.268	-1.643557	0.1065
JAN	-3917.995	2243.239	-1.746579	0.0869
FEB	-4257.022	2108.397	-2.019080	0.0489
MAR	-4419.321	2106.918	-2.097529	0.0410
APR	-2474.999	2241.748	-1.104049	0.2749
MAY	-3053.519	2239.924	-1.363225	0.1789
JUN	-2121.013	2238.758	-0.947406	0.3480

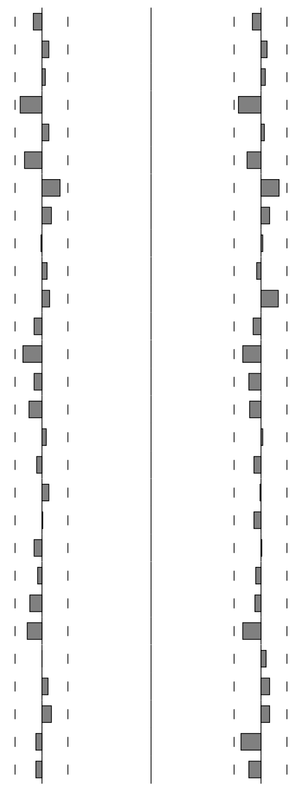
R-squared	0.271555	Mean dependent var	2573.683
Adjusted R-squared	0.111298	S.D. dependent var	4596.862
S.E. of regression	4333.508	Akaike info criterion	19.75813
Sum squared resid	9.39E+08	Schwarz criterion	20.16983
Log likelihood	-600.5020	Hannan-Quinn criter.	19.91977
F-statistic	1.694491	Durbin-Watson stat	2.084794
Prob(F-statistic)	0.102041		

obs	Actual	Fitted	Residual	Residual Plot
2009M02	20015.0	19973.8	41.1602	
2009M03	20022.0	20003.7	18.2827	
2009M04	19947.0	20024.1	-77.1362	
2009M05	19949.0	19914.3	34.7452	
2009M06	19864.0	19891.7	-27.7060	
2009M07	19944.0	19812.7	131.311	
2009M08	19924.0	19954.0	-29.9926	
2009M09	19953.0	19940.0	13.0273	
2009M10	20213.0	20085.5	127.473	
2009M11	20122.0	20267.0	-144.975	
2009M12	20222.0	20199.1	22.9202	
2010M01	20281.0	20261.1	19.8534	
2010M02	20304.0	20292.7	11.3237	
2010M03	20311.0	20309.2	1.75206	
2010M04	20369.0	20329.2	39.7771	
2010M05	20409.0	20339.4	69.6076	
2010M06	20390.0	20351.2	38.8235	
2010M07	20267.0	20331.3	-64.2748	
2010M08	20231.0	20291.1	-60.1447	
2010M09	20275.0	20262.9	12.1098	
2010M10	20321.0	20422.0	-100.958	
2010M11	20435.0	20412.2	22.7645	
2010M12	20512.0	20527.8	-15.8131	
2011M01	20558.0	20569.6	-11.6369	
2011M02	20585.0	20589.1	-4.11971	
2011M03	20618.0	20609.4	8.55150	
2011M04	20682.0	20651.8	30.1813	
2011M05	20642.0	20669.5	-27.5212	
2011M06	20552.0	20610.5	-58.4856	
2011M07	20448.0	20527.2	-79.1921	
2011M08	20413.0	20504.5	-91.5333	
2011M09	20478.0	20477.3	0.70296	
2011M10	20637.0	20655.6	-18.5637	
2011M11	20773.0	20746.8	26.1764	
2011M12	20859.0	20882.5	-23.4724	
2012M01	20922.0	20932.2	-10.1809	
2012M02	20945.0	20968.4	-23.4053	
2012M03	20970.0	20985.1	-15.0880	
2012M04	21015.0	21023.7	-8.71263	
2012M05	21004.0	21018.1	-14.1090	
2012M06	21062.0	20983.4	78.6364	
2012M07	21103.0	21032.6	70.3742	
2012M08	21095.0	21139.0	-44.0429	
2012M09	21176.0	21136.1	39.8684	
2012M10	21319.0	21328.3	-9.32382	
2012M11	21449.0	21405.3	43.6630	
2012M12	21541.0	21535.2	5.75613	
2013M01	21604.0	21590.4	13.6266	
2013M02	21631.0	21625.6	5.37761	
2013M03	21643.0	21645.9	-2.88029	
2013M04	21720.0	21670.8	49.2206	
2013M05	21672.0	21697.5	-25.4601	
2013M06	21641.0	21630.6	10.3909	
2013M07	21588.0	21599.6	-11.6444	
2013M08	21496.0	21623.2	-127.204	
2013M09	21536.0	21545.4	-9.38106	
2013M10	21719.0	21700.6	18.4424	
2013M11	21886.0	21814.5	71.4546	
2013M12	22010.0	21978.1	31.9441	
2014M01	22074.0	22061.8	12.1899	
2014M02	22095.0	22098.7	-3.67014	
2014M03	22133.0	22113.8	19.1947	



Correlogram of Residuals

Date: 01/06/15 Time: 14:13
Sample: 2009M02 2014M03
Included observations: 62
Q-statistic probabilities adjusted for 1 ARMA term(s)



Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	-0.079	-0.079	0.4065	
		2	0.067	0.061	0.7040	0.401
		3	0.034	0.044	0.7826	0.676
		4	-0.205	-0.205	3.6458	0.302
		5	0.073	0.041	4.0201	0.403
		6	-0.158	-0.129	5.7893	0.327
		7	0.174	0.174	7.9695	0.240
		8	0.090	0.088	8.5708	0.285
		9	-0.002	0.021	8.5710	0.380
		10	0.051	-0.034	8.7720	0.459
		11	0.079	0.168	9.2518	0.508
		12	-0.066	-0.069	9.6023	0.566
		13	-0.174	-0.171	12.056	0.441
		14	-0.069	-0.109	12.453	0.491
		15	-0.120	-0.099	13.659	0.475
		16	0.049	0.020	13.862	0.536
		17	-0.045	-0.059	14.038	0.596
		18	0.073	-0.002	14.512	0.631
		19	0.016	-0.058	14.536	0.694
		20	-0.070	0.016	15.003	0.722
		21	-0.035	-0.045	15.124	0.769
		22	-0.112	-0.052	16.377	0.748
		23	-0.133	-0.170	18.184	0.695
		24	0.000	0.055	18.184	0.747
		25	0.063	0.084	18.604	0.773
		26	0.091	0.083	19.507	0.772
		27	-0.054	-0.182	19.835	0.799
		28	-0.055	-0.114	20.185	0.823

Dependent Variable: N_RH_UPC
Method: Least Squares
Date: 05/05/14 Time: 11:32
Sample (adjusted): 2009M12 2014M03
Included observations: 52 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_BC	0.061042	0.004106	14.86680	0.0000
EDD_BC*APR	0.046884	0.010278	4.561709	0.0000
EDD_BC*DEC	0.035232	0.008428	4.180260	0.0001
EDD_BC*JAN	0.050279	0.006822	7.370028	0.0000
EDD_BC*FEB	0.050031	0.006761	7.399408	0.0000
EDD_BC*MAR	0.050397	0.007703	6.542724	0.0000
(RH_PRICE)*(DEC+JAN+FEB+MAR+A	-0.849114	0.420407	-2.019741	0.0495
C	13.43071	1.274733	10.53610	0.0000

R-squared	0.991830	Mean dependent var	66.61300
Adjusted R-squared	0.990531	S.D. dependent var	48.22743
S.E. of regression	4.693011	Akaike info criterion	6.070664
Sum squared resid	969.0716	Schwarz criterion	6.370855
Log likelihood	-149.8373	Hannan-Quinn criter.	6.185750
F-statistic	763.1232	Durbin-Watson stat	2.101960
Prob(F-statistic)	0.000000		

Variable Name	Definition
EDD_BC	Bill Cycle EDD
EDD_BC*APR	Interaction Variable - Bill Cycle EDD * April
EDD_BC*DEC	Interaction Variable - Bill Cycle EDD * December
EDD_BC*JAN	Interaction Variable - Bill Cycle EDD * January
EDD_BC*FEB	Interaction Variable - Bill Cycle EDD * February
EDD_BC*MAR	Interaction Variable - Bill Cycle EDD * March
(RH_PRICE)*(DEC+JAN+FEB+MAR+APR)	Interaction Variable - Residential Natural Gas Price * December - April
C	Constant

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	1.200403	Prob. F(7,44)	0.3227
Obs*R-squared	8.338226	Prob. Chi-Square(7)	0.3037
Scaled explained SS	6.468970	Prob. Chi-Square(7)	0.4862

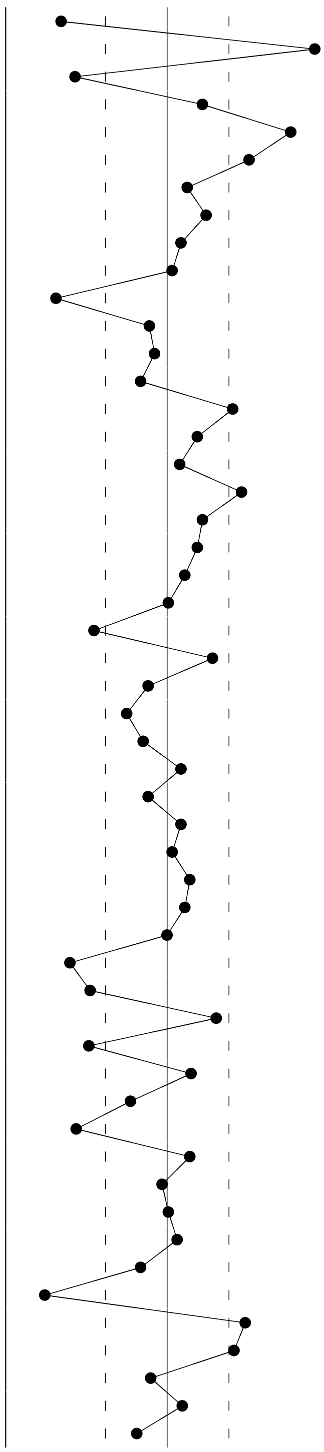
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 14:27
Sample: 2009M12 2014M03
Included observations: 52

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	5.969687	7.423193	0.804194	0.4256
EDD_BC	0.042061	0.023910	1.759139	0.0855
EDD_BC*APR	-0.060175	0.059850	-1.005419	0.3202
EDD_BC*DEC	-0.068685	0.049081	-1.399426	0.1687
EDD_BC*JAN	-0.050534	0.039727	-1.272016	0.2100
EDD_BC*FEB	-0.065447	0.039374	-1.662183	0.1036
EDD_BC*MAR	-0.081137	0.044856	-1.808857	0.0773
(RH_PRICE)*(DEC+JAN+FEB+MAR+A	2.527878	2.448172	1.032558	0.3075

R-squared	0.160351	Mean dependent var	18.63599
Adjusted R-squared	0.026770	S.D. dependent var	27.70228
S.E. of regression	27.32897	Akaike info criterion	9.594410
Sum squared resid	32862.39	Schwarz criterion	9.894601
Log likelihood	-241.4547	Hannan-Quinn criter.	9.709496
F-statistic	1.200403	Durbin-Watson stat	1.515362
Prob(F-statistic)	0.322699		

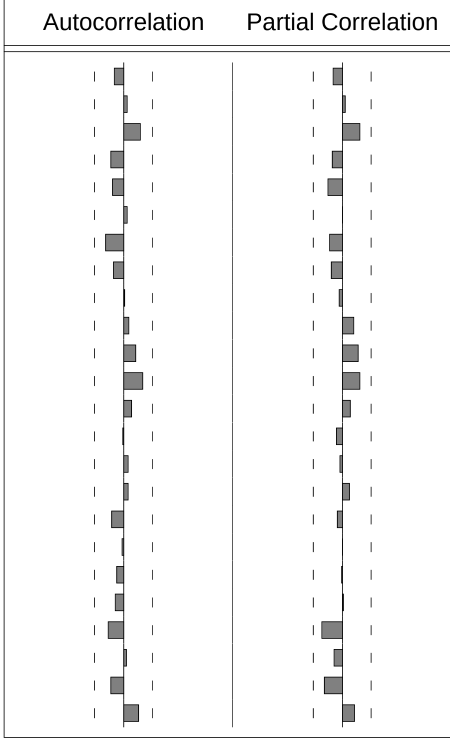
obs	Actual	Fitted	Residual
2009M12	74.2639	82.3135	-8.04958
2010M01	155.741	144.559	11.1814
2010M02	128.946	135.955	-7.00864
2010M03	100.897	98.2397	2.65731
2010M04	74.0408	64.6498	9.39095
2010M05	42.7762	36.5045	6.27169
2010M06	22.8521	21.3051	1.54700
2010M07	17.5977	14.5905	3.00716
2010M08	14.6921	13.6138	1.07826
2010M09	16.4870	16.0555	0.43146
2010M10	21.3693	29.8509	-8.48170
2010M11	51.1996	52.4974	-1.29787
2010M12	93.3744	94.3365	-0.96205
2011M01	139.614	141.601	-1.98685
2011M02	156.315	151.292	5.02308
2011M03	121.344	119.085	2.25929
2011M04	91.0128	90.0663	0.94645
2011M05	46.6750	41.0216	5.65342
2011M06	28.1928	25.5170	2.67585
2011M07	18.5159	16.1776	2.33827
2011M08	14.8831	13.5528	1.33032
2011M09	16.5070	16.4218	0.08521
2011M10	19.8296	25.3949	-5.56527
2011M11	51.8854	48.4687	3.41673
2011M12	69.8644	71.2850	-1.42065
2012M01	121.751	124.778	-3.02617
2012M02	118.850	120.682	-1.83229
2012M03	100.812	99.7504	1.06168
2012M04	62.8381	64.2300	-1.39191
2012M05	39.2192	38.1526	1.06655
2012M06	23.4890	23.0753	0.41367
2012M07	17.1379	15.4451	1.69285
2012M08	14.8566	13.4918	1.36482
2012M09	16.1294	16.1166	0.01286
2012M10	23.2047	30.5835	-7.37875
2012M11	48.3399	54.2066	-5.86674
2012M12	94.6321	90.9243	3.70775
2013M01	124.199	130.160	-5.96035
2013M02	141.305	139.518	1.78692
2013M03	112.458	115.278	-2.81988
2013M04	82.8643	89.7298	-6.86545
2013M05	42.7209	40.9606	1.76039
2013M06	24.5553	24.9066	-0.35124
2013M07	15.6284	15.5061	0.12231
2013M08	15.0195	14.2853	0.73417
2013M09	15.6489	17.7036	-2.05473
2013M10	20.7441	30.0341	-9.28995
2013M11	58.2187	52.3143	5.90433
2013M12	109.334	104.200	5.13478
2014M01	149.105	150.396	-1.29147
2014M02	147.611	146.442	1.16929
2014M03	134.326	136.651	-2.32472

Residual Plot



Correlogram of Residuals

Date: 01/06/15 Time: 14:27
Sample: 2009M12 2014M03
Included observations: 52



	AC	PAC	Q-Stat	Prob
1	-0.087	-0.087	0.4187	0.518
2	0.039	0.032	0.5047	0.777
3	0.158	0.166	1.9429	0.584
4	-0.117	-0.093	2.7432	0.602
5	-0.099	-0.136	3.3342	0.649
6	0.036	0.002	3.4153	0.755
7	-0.166	-0.122	5.1272	0.644
8	-0.095	-0.104	5.7038	0.680
9	0.009	-0.025	5.7085	0.769
10	0.057	0.110	5.9261	0.821
11	0.116	0.151	6.8555	0.811
12	0.183	0.170	9.2116	0.685
13	0.081	0.075	9.6814	0.720
14	-0.003	-0.051	9.6820	0.785
15	0.045	-0.018	9.8385	0.830
16	0.049	0.073	10.023	0.865
17	-0.112	-0.041	11.032	0.855
18	-0.016	0.007	11.052	0.892
19	-0.063	-0.001	11.389	0.910
20	-0.077	0.011	11.903	0.919
21	-0.146	-0.191	13.837	0.877
22	0.030	-0.077	13.922	0.904
23	-0.117	-0.170	15.248	0.886
24	0.147	0.118	17.421	0.830

Dependent Variable: N_RR_C
Method: Least Squares
Date: 05/16/14 Time: 09:38
Sample (adjusted): 2009M02 2014M03
Included observations: 62 after adjustments
Convergence achieved after 7 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
POP	1.186408	0.055303	21.45289	0.0000
OCT	-19.74155	7.983020	-2.472943	0.0166
NOV	-32.97412	10.24462	-3.218678	0.0022
DEC	-37.87332	11.12744	-3.403599	0.0013
JAN	-38.62668	10.97972	-3.518003	0.0009
FEB	-35.17947	9.982251	-3.524202	0.0009
MAR	-30.80091	7.969458	-3.864869	0.0003
D_2013M8	74.99570	13.72136	5.465618	0.0000
AR(1)	0.960963	0.034094	28.18583	0.0000

R-squared	0.938147	Mean dependent var	1593.516
Adjusted R-squared	0.928811	S.D. dependent var	71.16035
S.E. of regression	18.98651	Akaike info criterion	8.858815
Sum squared resid	19105.84	Schwarz criterion	9.167592
Log likelihood	-265.6233	Hannan-Quinn criter.	8.980049
Durbin-Watson stat	2.037565		
Inverted AR Roots	.96		

Variable Name	Definition
POP	Population
OCT	October
NOV	November
DEC	December
JAN	January
FEB	February
MAR	March
D_2013M8	Dummy, August 2013
AR(1)	Autoregressive Term, lag 1

Heteroskedasticity Test: Breusch-Pagan-Godfrey

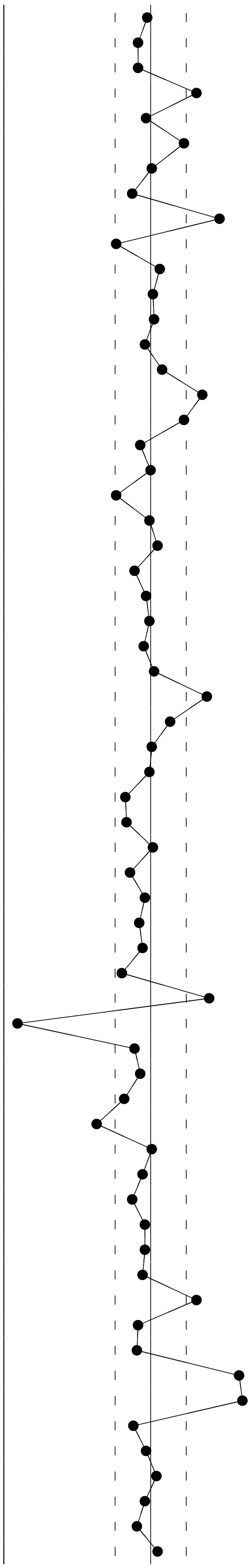
F-statistic	1.575407	Prob. F(8,53)	0.1545
Obs*R-squared	11.91103	Prob. Chi-Square(8)	0.1552
Scaled explained SS	27.56007	Prob. Chi-Square(8)	0.0006

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 14:16
Sample: 2009M02 2014M03
Included observations: 62

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-42482.80	40545.72	-1.047775	0.2995
POP	32.55545	30.73356	1.059280	0.2943
OCT	-7.702369	365.7691	-0.021058	0.9833
NOV	-423.0482	366.1623	-1.155357	0.2531
DEC	-451.2065	366.6500	-1.230619	0.2239
JAN	-485.5995	367.2220	-1.322359	0.1917
FEB	-471.1146	338.7945	-1.390562	0.1702
MAR	-474.9804	339.1368	-1.400557	0.1672
D_2013M8	1590.189	780.8850	2.036394	0.0467

R-squared	0.192113	Mean dependent var	308.1588
Adjusted R-squared	0.070168	S.D. dependent var	781.8111
S.E. of regression	753.8831	Akaike info criterion	16.22183
Sum squared resid	30122009	Schwarz criterion	16.53061
Log likelihood	-493.8768	Hannan-Quinn criter.	16.34307
F-statistic	1.575407	Durbin-Watson stat	1.999620
Prob(F-statistic)	0.154547		

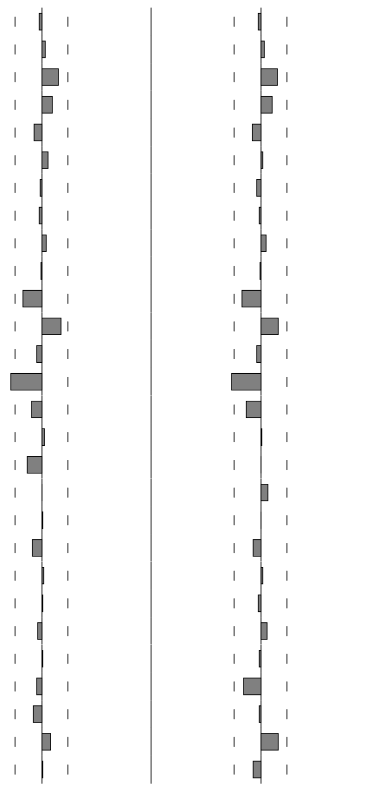
obs	Actual	Fitted	Residual	Residual Plot
2009M02	1640.00	1641.77	-1.76527	
2009M03	1633.00	1639.95	-6.95343	
2009M04	1653.00	1659.80	-6.80067	
2009M05	1674.00	1649.47	24.5345	
2009M06	1667.00	1669.66	-2.65635	
2009M07	1681.00	1662.93	18.0705	
2009M08	1677.00	1676.39	0.61419	
2009M09	1663.00	1672.54	-9.54179	
2009M10	1676.00	1639.35	36.6520	
2009M11	1639.00	1657.58	-18.5842	
2009M12	1635.00	1629.85	5.15329	
2010M01	1631.00	1629.96	1.03889	
2010M02	1632.00	1630.28	1.72085	
2010M03	1629.00	1632.32	-3.31829	
2010M04	1662.00	1655.97	6.02852	
2010M05	1686.00	1658.22	27.7835	
2010M06	1699.00	1681.31	17.6877	
2010M07	1688.00	1693.80	-5.80451	
2010M08	1683.00	1683.24	-0.24185	
2010M09	1660.00	1678.44	-18.4365	
2010M10	1636.00	1636.60	-0.59549	
2010M11	1623.00	1619.29	3.71018	
2010M12	1606.00	1614.62	-8.61720	
2011M01	1600.00	1602.26	-2.25895	
2011M02	1600.00	1600.61	-0.61374	
2011M03	1598.00	1601.70	-3.70168	
2011M04	1628.00	1626.24	1.75845	
2011M05	1656.00	1625.78	30.2223	
2011M06	1663.00	1652.77	10.2348	
2011M07	1660.00	1659.49	0.51340	
2011M08	1656.00	1656.64	-0.63655	
2011M09	1639.00	1652.79	-13.7876	
2011M10	1604.00	1616.73	-12.7320	
2011M11	1590.00	1588.83	1.16609	
2011M12	1572.00	1583.22	-11.2195	
2012M01	1567.00	1569.87	-2.87377	
2012M02	1563.00	1569.30	-6.30199	
2012M03	1562.00	1566.52	-4.52262	
2012M04	1577.00	1592.28	-15.2817	
2012M05	1608.00	1576.86	31.1359	
2012M06	1535.00	1606.61	-71.6068	
2012M07	1528.00	1536.48	-8.47829	
2012M08	1524.00	1529.75	-5.74520	
2012M09	1512.00	1525.92	-13.9233	
2012M10	1466.00	1494.65	-28.6522	
2012M11	1457.00	1456.20	0.79965	
2012M12	1451.00	1455.37	-4.37067	
2013M01	1444.00	1453.57	-9.57189	
2013M02	1448.00	1451.01	-3.00936	
2013M03	1453.00	1455.93	-2.93125	
2013M04	1483.00	1487.30	-4.29996	
2013M05	1511.00	1486.61	24.3868	
2013M06	1507.00	1513.55	-6.55282	
2013M07	1502.00	1509.68	-7.67605	
2013M08	1627.00	1579.96	47.0423	
2013M09	1602.00	1553.05	48.9534	
2013M10	1572.00	1581.32	-9.31567	
2013M11	1556.00	1558.33	-2.32998	
2013M12	1554.00	1550.80	3.19674	
2014M01	1550.00	1552.84	-2.83578	
2014M02	1546.00	1553.20	-7.20237	
2014M03	1554.00	1550.44	3.55780	



Correlogram of Residuals

Date: 01/06/15 Time: 14:15
Sample: 2009M02 2014M03
Included observations: 62
Q-statistic probabilities adjusted for 1 ARMA term(s)

Autocorrelation | Partial Correlation



	AC	PAC	Q-Stat	Prob
1	-0.019	-0.019	0.0240	
2	0.034	0.034	0.1009	0.751
3	0.159	0.160	1.7960	0.407
4	0.099	0.107	2.4612	0.482
5	-0.067	-0.075	2.7761	0.596
6	0.061	0.024	3.0395	0.694
7	-0.009	-0.035	3.0458	0.803
8	-0.021	-0.014	3.0796	0.878
9	0.046	0.050	3.2382	0.919
10	-0.001	-0.004	3.2383	0.954
11	-0.179	-0.176	5.7440	0.836
12	0.184	0.171	8.4394	0.673
13	-0.044	-0.035	8.5937	0.737
14	-0.288	-0.271	15.449	0.280
15	-0.096	-0.138	16.222	0.300
16	0.028	0.014	16.288	0.363
17	-0.132	0.002	17.813	0.335
18	0.000	0.071	17.813	0.401
19	0.009	0.006	17.821	0.468
20	-0.083	-0.074	18.473	0.491
21	0.023	0.018	18.525	0.553
22	0.011	-0.024	18.537	0.615
23	-0.036	0.063	18.665	0.666
24	0.016	-0.014	18.691	0.719
25	-0.049	-0.164	18.947	0.755
26	-0.079	-0.016	19.642	0.765
27	0.090	0.172	20.553	0.765
28	0.015	-0.069	20.578	0.806

Dependent Variable: N_RR_UPC
Method: Least Squares
Date: 05/16/14 Time: 09:46
Sample (adjusted): 2010M06 2014M03
Included observations: 46 after adjustments
Convergence achieved after 18 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_BC	0.016476	0.000691	23.86037	0.0000
C	49.54743	24.68038	2.007563	0.0517
D_2013M6	6.165801	1.772252	3.479077	0.0013
D_2013M7	-4.750431	1.724163	-2.755210	0.0089
RR_PRICE	-2.372112	0.999345	-2.373666	0.0226
AR(1)	0.554770	0.129215	4.293384	0.0001
AR(6)	0.383339	0.149365	2.566462	0.0142

R-squared	0.953722	Mean dependent var	18.64271
Adjusted R-squared	0.946602	S.D. dependent var	7.896355
S.E. of regression	1.824683	Akaike info criterion	4.179958
Sum squared resid	129.8493	Schwarz criterion	4.458230
Log likelihood	-89.13904	Hannan-Quinn criter.	4.284200
F-statistic	133.9558	Durbin-Watson stat	2.037373
Prob(F-statistic)	0.000000		

Inverted AR Roots	.98	.53-.71i	.53+.71i	-.35-.72i
	-.35+.72i	-.78		

Variable Name	Definition
EDD_BC	Bill Cycle EDD
C	Constant
D_2013M6	Dummy, June 2013 and forward
D_2013M7	Dummy, July 2013
RR_PRICE	Residential Non-Heating Natural Gas Price
AR(1)	Autoregressive Term, lag 1
AR(6)	Autoregressive Term, lag 6

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	0.750054	Prob. F(4,41)	0.5637
Obs*R-squared	3.136575	Prob. Chi-Square(4)	0.5352
Scaled explained SS	1.713907	Prob. Chi-Square(4)	0.7882

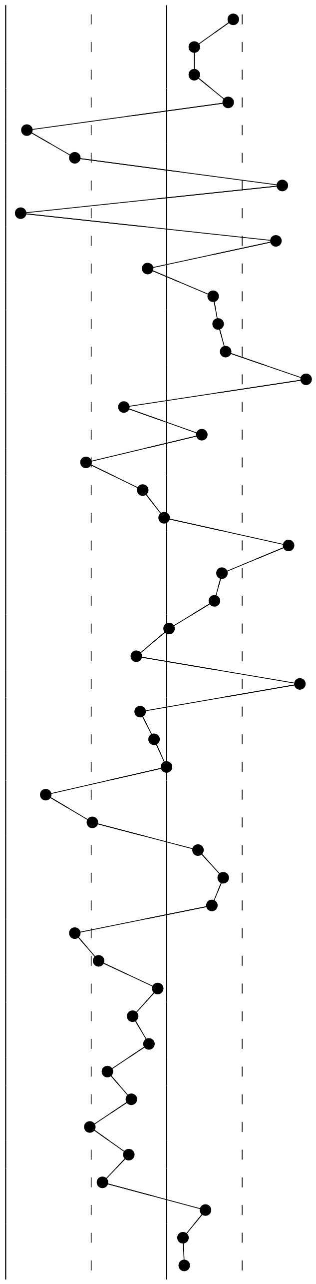
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 14:29
Sample: 2010M06 2014M03
Included observations: 46

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-28.50275	22.79940	-1.250154	0.2183
EDD_BC	0.000785	0.001169	0.671451	0.5057
D_2013M6	0.265962	4.000086	0.066489	0.9473
D_2013M7	-0.592307	3.904751	-0.151689	0.8802
RR_PRICE	1.606644	1.175337	1.366965	0.1791

R-squared	0.068186	Mean dependent var	2.822811
Adjusted R-squared	-0.022722	S.D. dependent var	3.519074
S.E. of regression	3.558830	Akaike info criterion	5.479063
Sum squared resid	519.2762	Schwarz criterion	5.677828
Log likelihood	-121.0184	Hannan-Quinn criter.	5.553522
F-statistic	0.750054	Durbin-Watson stat	1.816663
Prob(F-statistic)	0.563718		

obs	Actual	Fitted	Residual
2010M06	11.7580	10.1362	1.62184
2010M07	11.1174	10.4408	0.67657
2010M08	9.94772	9.29045	0.65727
2010M09	11.5375	10.0503	1.48719
2010M10	11.3820	14.7602	-3.37820
2010M11	16.1507	18.3688	-2.21809
2010M12	26.5639	23.7796	2.78430
2011M01	27.8123	31.3538	-3.54150
2011M02	33.2946	30.6462	2.64835
2011M03	27.9060	28.3664	-0.46045
2011M04	23.6548	22.5341	1.12073
2011M05	16.1495	14.9174	1.23213
2011M06	13.6212	12.2027	1.41845
2011M07	12.7774	9.39536	3.38200
2011M08	10.1668	11.2032	-1.03640
2011M09	11.6000	10.7435	0.85656
2011M10	11.6699	13.6021	-1.93226
2011M11	17.8287	18.4083	-0.57959
2011M12	21.4608	21.5068	-0.04602
2012M01	31.9473	29.0111	2.93613
2012M02	31.1450	29.8028	1.34220
2012M03	27.8663	26.7129	1.15336
2012M04	20.5354	20.4775	0.05789
2012M05	15.2283	15.9662	-0.73791
2012M06	14.2544	11.0191	3.23526
2012M07	11.3531	12.0057	-0.65263
2012M08	10.6775	10.9767	-0.29920
2012M09	11.5205	11.5157	0.00488
2012M10	11.5926	14.5251	-2.93258
2012M11	16.0797	17.8803	-1.80060
2012M12	23.9664	23.2003	0.76613
2013M01	30.0061	28.6489	1.35722
2013M02	32.9757	31.8781	1.09765
2013M03	27.1693	29.4010	-2.23164
2013M04	22.4164	24.0713	-1.65483
2013M05	16.2411	16.4472	-0.20608
2013M06	18.4994	19.3344	-0.83497
2013M07	5.59285	6.02399	-0.43114
2013M08	9.83455	11.2630	-1.42844
2013M09	9.86489	10.7301	-0.86521
2013M10	10.6693	12.5313	-1.86204
2013M11	15.9354	16.8592	-0.92386
2013M12	22.0318	23.5859	-1.55418
2014M01	28.6860	27.7434	0.94255
2014M02	28.3522	27.9595	0.39264
2014M03	26.7242	26.2876	0.43654

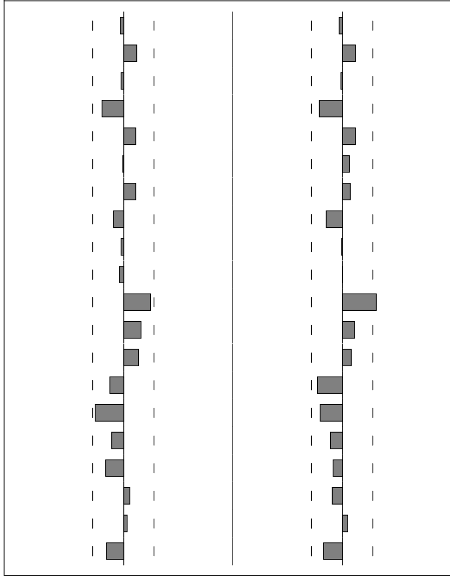
Residual Plot



Correlogram of Residuals

Date: 01/06/15 Time: 14:28
Sample: 2010M06 2014M03
Included observations: 46
Q-statistic probabilities adjusted for 2 ARMA term(s)

Autocorrelation | Partial Correlation



	AC	PAC	Q-Stat	Prob
1	-0.030	-0.030	0.0428	
2	0.129	0.128	0.8716	
3	-0.022	-0.015	0.8955	0.344
4	-0.200	-0.221	2.9975	0.223
5	0.121	0.123	3.7858	0.286
6	-0.001	0.067	3.7858	0.436
7	0.119	0.079	4.5931	0.468
8	-0.095	-0.154	5.1152	0.529
9	-0.020	-0.001	5.1391	0.643
10	-0.036	0.008	5.2199	0.734
11	0.255	0.327	9.3265	0.408
12	0.167	0.121	11.129	0.348
13	0.143	0.083	12.503	0.327
14	-0.126	-0.237	13.596	0.327
15	-0.269	-0.213	18.732	0.132
16	-0.109	-0.110	19.607	0.143
17	-0.168	-0.089	21.756	0.114
18	0.058	-0.096	22.026	0.142
19	0.039	0.051	22.149	0.179
20	-0.164	-0.175	24.428	0.142

Dependent Variable: N_LLF_C_T
Method: Least Squares
Date: 05/05/14 Time: 11:09
Sample (adjusted): 2009M12 2014M03
Included observations: 52 after adjustments
Convergence achieved after 151 iterations
MA Backcast: 2009M11

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EMPNM	9.674519	1.517729	6.374337	0.0000
SEP	30.84029	8.505041	3.626120	0.0008
OCT	104.6018	13.22668	7.908397	0.0000
NOV	144.0781	15.66665	9.196486	0.0000
DEC	169.9714	16.76957	10.13571	0.0000
JAN	181.9144	16.96717	10.72156	0.0000
FEB	169.7059	16.59765	10.22470	0.0000
MAR	141.8438	15.56585	9.112497	0.0000
APR	86.62266	13.11040	6.607173	0.0000
MAY	26.79028	8.203699	3.265634	0.0023
D_2013M12	-18.65196	10.73960	-1.736746	0.0905
D_2010M7	-15.74887	10.05700	-1.565961	0.1256
AR(1)	0.985551	0.032444	30.37728	0.0000
MA(1)	0.391837	0.159785	2.452274	0.0189

R-squared	0.992549	Mean dependent var	5186.904
Adjusted R-squared	0.989999	S.D. dependent var	171.4588
S.E. of regression	17.14647	Akaike info criterion	8.746266
Sum squared resid	11172.06	Schwarz criterion	9.271601
Log likelihood	-213.4029	Hannan-Quinn criter.	8.947667
Durbin-Watson stat	1.924852		

Inverted AR Roots	.99
Inverted MA Roots	-.39

Variable Name	Definition
EMPNM	Non-Manufacturing Employment
SEP	September
OCT	October
NOV	November
DEC	December
JAN	January
FEB	February
MAR	March
APR	April
MAY	May
D_2013M12	Dummy, December 2013
D_2010M7	Dummy, July 2010
AR(1)	Autoregressive Term, lag 1
MA(1)	Moving Average Term, lag 1

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	1.101990	Prob. F(12,39)	0.3858
Obs*R-squared	13.16719	Prob. Chi-Square(12)	0.3570
Scaled explained SS	4.666454	Prob. Chi-Square(12)	0.9682

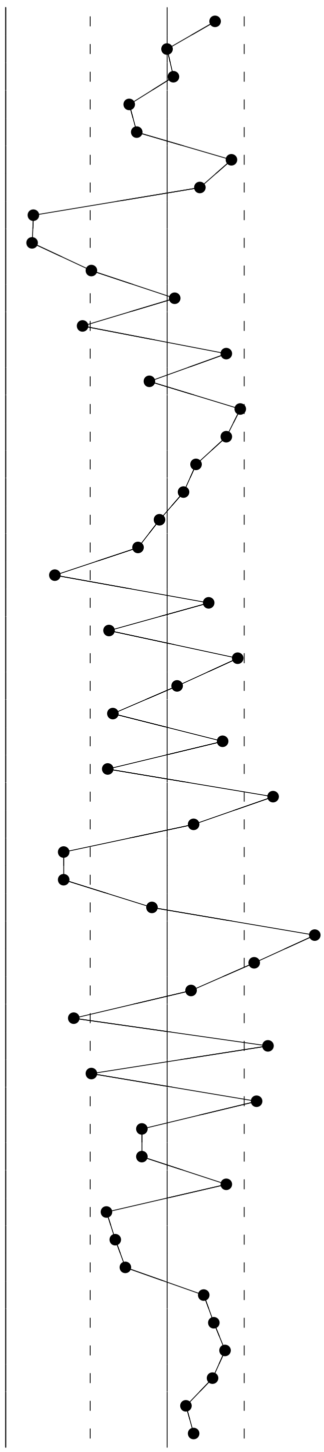
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 14:22
Sample: 2009M12 2014M03
Included observations: 52

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-149.0869	3051.024	-0.048865	0.9613
EMPNM	0.776059	5.387938	0.144036	0.8862
SEP	92.62847	144.2408	0.642179	0.5245
OCT	-139.1919	144.5136	-0.963175	0.3414
NOV	-106.8383	144.7229	-0.738226	0.4648
DEC	-105.4554	144.7408	-0.728581	0.4706
JAN	-137.4417	133.2306	-1.031607	0.3086
FEB	-144.9774	133.3314	-1.087346	0.2836
MAR	-121.4745	133.5728	-0.909425	0.3687
APR	-120.8225	144.2109	-0.837818	0.4072
MAY	-219.3545	144.2116	-1.521060	0.1363
D_2013M12	-30.02515	286.0966	-0.104948	0.9170
D_2010M7	608.1484	260.8331	2.331562	0.0250

R-squared	0.253215	Mean dependent var	214.8472
Adjusted R-squared	0.023435	S.D. dependent var	249.9355
S.E. of regression	246.9895	Akaike info criterion	14.06889
Sum squared resid	2379149.	Schwarz criterion	14.55670
Log likelihood	-352.7911	Hannan-Quinn criter.	14.25590
F-statistic	1.101990	Durbin-Watson stat	2.028406
Prob(F-statistic)	0.385776		

obs	Actual	Fitted	Residual
2009M12	5076.00	5065.30	10.7015
2010M01	5087.00	5086.88	0.11886
2010M02	5090.00	5088.52	1.48324
2010M03	5071.00	5079.36	-8.36255
2010M04	5029.00	5035.88	-6.88493
2010M05	4987.00	4972.73	14.2681
2010M06	4975.00	4967.56	7.44309
2010M07	4931.00	4960.88	-29.8804
2010M08	4912.00	4942.06	-30.0612
2010M09	4925.00	4941.85	-16.8496
2010M10	5004.00	5002.41	1.59103
2010M11	5036.00	5054.83	-18.8263
2010M12	5078.00	5064.76	13.2355
2011M01	5101.00	5104.89	-3.88800
2011M02	5115.00	5098.59	16.4068
2011M03	5117.00	5103.85	13.1531
2011M04	5088.00	5081.51	6.49094
2011M05	5037.00	5033.35	3.65127
2011M06	5012.00	5013.62	-1.61724
2011M07	4998.00	5004.58	-6.58012
2011M08	4984.00	5009.01	-25.0102
2011M09	5033.00	5023.59	9.40784
2011M10	5117.00	5129.85	-12.8472
2011M11	5183.00	5167.25	15.7513
2011M12	5230.00	5227.69	2.31066
2012M01	5246.00	5258.23	-12.2332
2012M02	5251.00	5238.59	12.4064
2012M03	5224.00	5237.25	-13.2526
2012M04	5195.00	5171.38	23.6181
2012M05	5161.00	5155.23	5.76883
2012M06	5125.00	5148.07	-23.0679
2012M07	5104.00	5127.00	-22.9983
2012M08	5105.00	5108.24	-3.23926
2012M09	5180.00	5147.24	32.7637
2012M10	5301.00	5281.58	19.4231
2012M11	5361.00	5355.62	5.38130
2012M12	5375.00	5395.90	-20.9039
2013M01	5405.00	5382.62	22.3780
2013M02	5397.00	5413.98	-16.9790
2013M03	5395.00	5375.05	19.9480
2013M04	5362.00	5367.50	-5.49938
2013M05	5295.00	5300.75	-5.75202
2013M06	5278.00	5264.88	13.1156
2013M07	5258.00	5271.52	-13.5163
2013M08	5255.00	5266.66	-11.6575
2013M09	5291.00	5300.34	-9.34298
2013M10	5394.00	5385.95	8.04645
2013M11	5456.00	5445.55	10.4463
2013M12	5485.00	5472.20	12.7966
2014M01	5530.00	5520.01	9.99237
2014M02	5539.00	5534.91	4.08870
2014M03	5535.00	5529.14	5.86223

Residual Plot



Correlogram of Residuals

Date: 01/06/15 Time: 14:21
Sample: 2009M12 2014M03
Included observations: 52
Q-statistic probabilities adjusted for 2 ARMA term(s)

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	0.031	0.031	0.0528	
		2	0.029	0.028	0.1014	
		3	-0.248	-0.251	3.6357	0.057
		4	-0.095	-0.085	4.1683	0.124
		5	0.139	0.173	5.3303	0.149
		6	-0.134	-0.218	6.4291	0.169
		7	-0.082	-0.148	6.8519	0.232
		8	-0.211	-0.125	9.6949	0.138
		9	0.112	0.088	10.518	0.161
		10	-0.075	-0.218	10.889	0.208
		11	0.166	0.121	12.779	0.173
		12	0.019	0.055	12.804	0.235
		13	0.071	0.024	13.171	0.282
		14	0.133	0.079	14.475	0.271
		15	-0.195	-0.154	17.354	0.184
		16	0.109	0.099	18.278	0.194
		17	-0.166	-0.080	20.486	0.154
		18	0.108	0.035	21.452	0.162
		19	0.008	0.092	21.457	0.207
		20	-0.052	-0.043	21.698	0.246
		21	0.025	0.046	21.755	0.297
		22	-0.005	0.072	21.757	0.354
		23	0.225	0.170	26.675	0.182
		24	-0.014	-0.000	26.696	0.223

Dependent Variable: N_LLF_UPC_T
Method: Least Squares
Date: 05/05/14 Time: 12:07
Sample (adjusted): 2009M12 2014M03
Included observations: 52 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_BC	0.474429	0.025609	18.52593	0.0000
C	84.73114	8.652339	9.792859	0.0000
EDD_BC*(NOV+DEC+JAN+FEB+MAR)	0.313110	0.034998	8.946576	0.0000
LLF_PRICE*(NOV+DEC+JAN+FEB+MA	-13.94695	1.938906	-7.193206	0.0000

R-squared	0.988609	Mean dependent var	429.1702
Adjusted R-squared	0.987897	S.D. dependent var	300.4479
S.E. of regression	33.05391	Akaike info criterion	9.907960
Sum squared resid	52442.94	Schwarz criterion	10.05806
Log likelihood	-253.6070	Hannan-Quinn criter.	9.965504
F-statistic	1388.564	Durbin-Watson stat	1.633634
Prob(F-statistic)	0.000000		

Variable Name	Definition
EDD_BC	Bill Cycle EDD
C	Constant
EDD_BC*(NOV+DEC+JAN+FEB+MAR)	Interaction Variable - Bill Cycle EDD * November - March
LLF_PRICE*(NOV+DEC+JAN+FEB+MAR)	Interaction Variable - LLF Natural Gas Price * November - March

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	2.017375	Prob. F(3,48)	0.1240
Obs*R-squared	5.822352	Prob. Chi-Square(3)	0.1206
Scaled explained SS	4.971245	Prob. Chi-Square(3)	0.1739

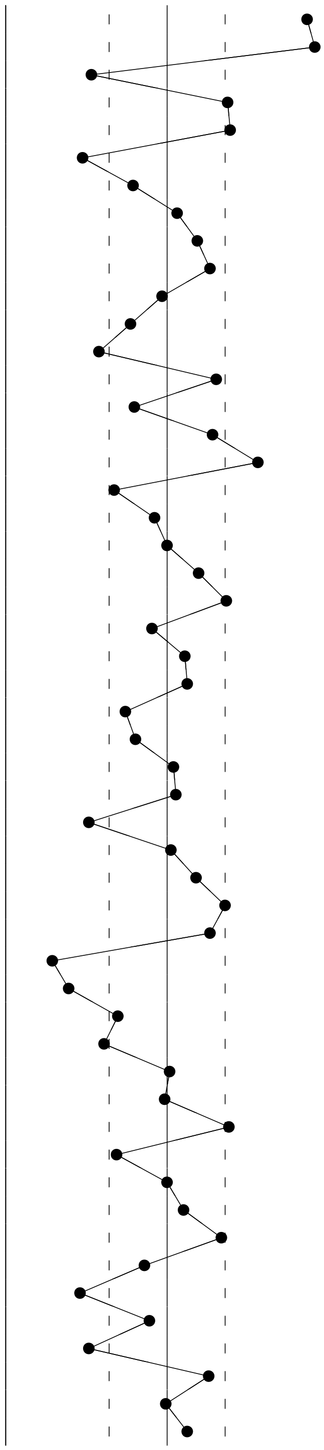
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 14:31
Sample: 2009M12 2014M03
Included observations: 52

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	311.2121	366.5642	0.848998	0.4001
EDD_BC	1.992226	1.084944	1.836248	0.0725
EDD_BC*(NOV+DEC+JAN+FEB+MAR)	-2.898401	1.482712	-1.954797	0.0564
LLF_PRICE*(NOV+DEC+JAN+FEB+MA	135.5890	82.14353	1.650636	0.1053

R-squared	0.111968	Mean dependent var	1008.518
Adjusted R-squared	0.056466	S.D. dependent var	1441.653
S.E. of regression	1400.359	Akaike info criterion	17.40065
Sum squared resid	94128281	Schwarz criterion	17.55074
Log likelihood	-448.4169	Hannan-Quinn criter.	17.45819
F-statistic	2.017375	Durbin-Watson stat	0.963307
Prob(F-statistic)	0.123987		

obs	Actual	Fitted	Residual
2009M12	615.931	536.972	78.9595
2010M01	976.158	893.266	82.8918
2010M02	799.754	842.402	-42.6474
2010M03	611.191	577.197	33.9943
2010M04	407.021	371.286	35.7350
2010M05	216.581	264.065	-47.4837
2010M06	127.020	145.932	-18.9124
2010M07	99.4224	93.7453	5.67707
2010M08	103.190	86.1544	17.0352
2010M09	129.242	105.132	24.1103
2010M10	209.491	212.352	-2.86121
2010M11	372.425	392.959	-20.5343
2010M12	624.205	662.353	-38.1481
2011M01	919.155	891.394	27.7612
2011M02	941.759	960.451	-18.6914
2011M03	753.480	727.961	25.5188
2011M04	533.903	482.777	51.1262
2011M05	268.941	299.173	-30.2314
2011M06	171.472	178.668	-7.19608
2011M07	106.015	106.080	-0.06537
2011M08	103.768	85.6800	18.0884
2011M09	141.560	107.978	33.5817
2011M10	169.167	177.719	-8.55213
2011M11	342.823	333.177	9.64648
2011M12	479.376	467.996	11.3800
2012M01	742.985	766.718	-23.7331
2012M02	721.923	739.559	-17.6363
2012M03	592.187	588.466	3.72106
2012M04	374.615	369.863	4.75246
2012M05	232.407	276.875	-44.4674
2012M06	161.533	159.691	1.84234
2012M07	116.980	100.387	16.5925
2012M08	118.255	85.2056	33.0494
2012M09	130.133	105.606	24.5269
2012M10	153.253	218.046	-64.7925
2012M11	348.978	404.597	-55.6192
2012M12	603.749	631.344	-27.5953
2013M01	778.741	814.490	-35.7488
2013M02	891.258	889.652	1.60560
2013M03	719.343	720.731	-1.38850
2013M04	508.413	473.763	34.6502
2013M05	269.981	298.698	-28.7173
2013M06	173.929	173.924	0.00549
2013M07	110.463	100.862	9.60178
2013M08	121.885	91.3731	30.5115
2013M09	104.983	117.941	-12.9579
2013M10	164.769	213.776	-49.0065
2013M11	410.823	420.662	-9.83862
2013M12	717.419	761.793	-44.3749
2014M01	996.940	973.168	23.7721
2014M02	944.897	945.561	-0.66376
2014M03	882.957	871.231	11.7263

Residual Plot



Correlogram of Residuals

Date: 01/06/15 Time: 14:32
Sample: 2009M12 2014M03
Included observations: 52

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	0.122	0.122	0.8253	0.364
		2	-0.128	-0.146	1.7503	0.417
		3	-0.001	0.036	1.7504	0.626
		4	-0.138	-0.168	2.8718	0.580
		5	-0.046	0.004	2.9971	0.700
		6	-0.013	-0.056	3.0079	0.808
		7	0.114	0.134	3.8200	0.800
		8	0.021	-0.053	3.8472	0.871
		9	0.037	0.086	3.9373	0.915
		10	-0.060	-0.116	4.1791	0.939
		11	-0.004	0.093	4.1801	0.964
		12	0.277	0.248	9.5556	0.655
		13	-0.034	-0.084	9.6391	0.723
		14	-0.165	-0.120	11.643	0.635
		15	-0.003	0.015	11.644	0.706
		16	-0.010	0.025	11.653	0.768
		17	0.092	0.140	12.331	0.780
		18	-0.044	-0.142	12.488	0.821
		19	-0.004	-0.025	12.489	0.864
		20	0.086	0.076	13.132	0.872
		21	-0.056	-0.028	13.421	0.893
		22	-0.040	0.015	13.574	0.916
		23	0.148	0.161	15.705	0.868
		24	0.128	-0.041	17.339	0.834

Dependent Variable: N_HLF_C_T
Method: Least Squares
Date: 05/05/14 Time: 10:55
Sample (adjusted): 2009M12 2014M03
Included observations: 52 after adjustments
Convergence achieved after 15 iterations
MA Backcast: 2009M11

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EMPM	17.70788	1.373076	12.89651	0.0000
SEP	-9.494653	3.770744	-2.517978	0.0159
OCT	-42.70437	5.715955	-7.471082	0.0000
NOV	-47.61587	6.763149	-7.040489	0.0000
DEC	-51.02606	7.076297	-7.210841	0.0000
JAN	-50.68535	7.007170	-7.233356	0.0000
FEB	-51.15098	6.586784	-7.765699	0.0000
MAR	-41.43036	5.727980	-7.232978	0.0000
APR	-21.22221	3.543926	-5.988333	0.0000
D_2012M9	-16.88006	5.170880	-3.264447	0.0023
AR(1)	0.967709	0.042617	22.70728	0.0000
MA(1)	0.423607	0.160686	2.636247	0.0119

R-squared	0.975450	Mean dependent var	1199.385
Adjusted R-squared	0.968699	S.D. dependent var	42.15060
S.E. of regression	7.457377	Akaike info criterion	7.055459
Sum squared resid	2224.499	Schwarz criterion	7.505746
Log likelihood	-171.4419	Hannan-Quinn criter.	7.228088
Durbin-Watson stat	1.980182		

Inverted AR Roots	.97
Inverted MA Roots	-.42

Variable Name	Definition
EMPM	Manufacturing Employment
SEP	September
OCT	October
NOV	November
DEC	December
JAN	January
FEB	February
MAR	March
APR	April
D_2012M9	Dummy, September 2012
AR(1)	Autoregressive Term, lag 1
MA(1)	Moving Average Term, lag 1

Heteroskedasticity Test: Harvey

F-statistic	1.161798	Prob. F(10,41)	0.3434
Obs*R-squared	11.48153	Prob. Chi-Square(10)	0.3213
Scaled explained SS	15.92946	Prob. Chi-Square(10)	0.1017

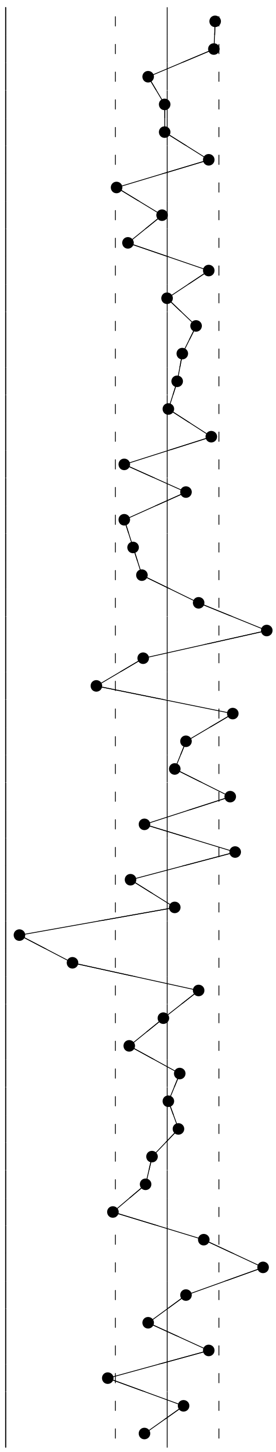
Test Equation:
Dependent Variable: LRESID2
Method: Least Squares
Date: 01/06/15 Time: 14:18
Sample: 2009M12 2014M03
Included observations: 52

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-46.24873	69.94507	-0.661215	0.5122
EMPM	0.741042	1.058247	0.700254	0.4877
SEP	1.211234	1.637171	0.739833	0.4636
OCT	-1.581863	1.462697	-1.081470	0.2858
NOV	-0.042236	1.458226	-0.028964	0.9770
DEC	-0.199138	1.341311	-0.148465	0.8827
JAN	0.691599	1.340393	0.515968	0.6086
FEB	-2.078200	1.335789	-1.555785	0.1274
MAR	-2.469436	1.333024	-1.852507	0.0712
APR	-1.039624	1.457778	-0.713157	0.4798
D_2012M9	2.349575	3.020073	0.777986	0.4410

R-squared	0.220799	Mean dependent var	2.222296
Adjusted R-squared	0.030750	S.D. dependent var	2.642117
S.E. of regression	2.601178	Akaike info criterion	4.935211
Sum squared resid	277.4111	Schwarz criterion	5.347974
Log likelihood	-117.3155	Hannan-Quinn criter.	5.093455
F-statistic	1.161798	Durbin-Watson stat	1.957196
Prob(F-statistic)	0.343371		

obs	Actual	Fitted	Residual
2009M12	1221.00	1214.20	6.80148
2010M01	1221.00	1214.29	6.70864
2010M02	1219.00	1221.78	-2.77787
2010M03	1227.00	1227.37	-0.37031
2010M04	1248.00	1248.28	-0.28255
2010M05	1273.00	1267.05	5.94962
2010M06	1265.00	1272.26	-7.26414
2010M07	1258.00	1258.72	-0.72262
2010M08	1250.00	1255.65	-5.64604
2010M09	1243.00	1236.93	6.06817
2010M10	1211.00	1211.01	-0.01454
2010M11	1209.00	1204.80	4.19896
2010M12	1208.00	1205.91	2.09304
2011M01	1209.00	1207.62	1.37968
2011M02	1208.00	1207.85	0.14564
2011M03	1223.00	1216.67	6.32884
2011M04	1239.00	1245.10	-6.10247
2011M05	1259.00	1256.31	2.69341
2011M06	1252.00	1258.15	-6.15452
2011M07	1245.00	1249.86	-4.85997
2011M08	1235.00	1238.69	-3.68989
2011M09	1224.00	1219.40	4.60449
2011M10	1201.00	1186.61	14.3867
2011M11	1196.00	1199.51	-3.50578
2011M12	1179.00	1189.24	-10.2392
2012M01	1184.00	1174.52	9.47957
2012M02	1187.00	1184.36	2.64071
2012M03	1195.00	1193.85	1.14751
2012M04	1220.00	1210.96	9.03889
2012M05	1239.00	1242.19	-3.18796
2012M06	1245.00	1235.28	9.71903
2012M07	1242.00	1247.34	-5.33668
2012M08	1237.00	1235.82	1.17610
2012M09	1186.00	1207.12	-21.1202
2012M10	1142.00	1155.65	-13.6493
2012M11	1136.00	1131.47	4.53122
2012M12	1135.00	1135.48	-0.48378
2013M01	1132.00	1137.36	-5.35633
2013M02	1130.00	1128.26	1.73657
2013M03	1139.00	1138.79	0.20934
2013M04	1158.00	1156.37	1.62663
2013M05	1178.00	1180.24	-2.23984
2013M06	1175.00	1178.17	-3.17183
2013M07	1168.00	1175.80	-7.80082
2013M08	1170.00	1164.66	5.34247
2013M09	1176.00	1162.16	13.8365
2013M10	1149.00	1146.22	2.77955
2013M11	1143.00	1145.77	-2.76983
2013M12	1146.00	1139.94	6.06163
2014M01	1141.00	1149.56	-8.55584
2014M02	1141.00	1138.66	2.33708
2014M03	1151.00	1154.23	-3.22595

Residual Plot



Correlogram of Residuals

Date: 01/06/15 Time: 14:18
Sample: 2009M12 2014M03
Included observations: 52
Q-statistic probabilities adjusted for 2 ARMA term(s)

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	-0.003	-0.003	0.0005	
		2	-0.048	-0.048	0.1277	
		3	-0.100	-0.100	0.6952	0.404
		4	-0.006	-0.010	0.6974	0.706
		5	-0.054	-0.064	0.8706	0.833
		6	-0.070	-0.083	1.1679	0.883
		7	-0.121	-0.133	2.0767	0.838
		8	0.003	-0.023	2.0773	0.912
		9	-0.019	-0.055	2.1019	0.954
		10	0.265	0.239	6.8123	0.557
		11	-0.276	-0.317	12.022	0.212
		12	-0.265	-0.307	16.948	0.076
		13	0.098	0.123	17.645	0.090
		14	0.002	-0.114	17.646	0.127
		15	0.064	0.024	17.953	0.159
		16	0.071	0.094	18.341	0.192
		17	0.106	0.076	19.243	0.203
		18	0.082	-0.007	19.804	0.229
		19	-0.095	-0.155	20.568	0.246
		20	0.025	-0.027	20.624	0.299
		21	-0.085	0.080	21.271	0.322
		22	-0.096	-0.026	22.140	0.333
		23	0.117	-0.077	23.462	0.320
		24	-0.104	-0.103	24.538	0.320

Dependent Variable: N_HLF_UPC_T
Method: Least Squares
Date: 05/05/14 Time: 12:08
Sample (adjusted): 2010M12 2014M03
Included observations: 40 after adjustments
Convergence achieved after 17 iterations
MA Backcast: 2009M12 2010M11

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_BC	0.428835	0.111530	3.845028	0.0005
HLF_PRICE	-71.19496	23.55849	-3.022052	0.0047
C	2561.637	871.0639	2.940815	0.0058
AR(12)	0.935671	0.082770	11.30453	0.0000
MA(12)	-0.849266	0.033423	-25.40984	0.0000

R-squared	0.977818	Mean dependent var	1426.763
Adjusted R-squared	0.975283	S.D. dependent var	333.2777
S.E. of regression	52.39624	Akaike info criterion	10.87202
Sum squared resid	96087.82	Schwarz criterion	11.08313
Log likelihood	-212.4403	Hannan-Quinn criter.	10.94835
F-statistic	385.7226	Durbin-Watson stat	1.709434
Prob(F-statistic)	0.000000		

Inverted AR Roots	.99	.86+.50i	.86-.50i	.50+.86i
	.50-.86i	.00+.99i	-.00-.99i	-.50+.86i
	-.50-.86i	-.86+.50i	-.86-.50i	-.99
Inverted MA Roots	.99	.85+.49i	.85-.49i	.49-.85i
	.49+.85i	-.00-.99i	-.00+.99i	-.49-.85i
	-.49+.85i	-.85+.49i	-.85-.49i	-.99

Variable Name	Definition
EDD_BC	Bill Cycle EDD
HLF_PRICE	HLF Natural Gas Price
C	Constant
AR(12)	Autoregressive Term, lag 12
MA(12)	Moving Average Term, lag 12

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	0.628835	Prob. F(2,37)	0.5388
Obs*R-squared	1.314947	Prob. Chi-Square(2)	0.5182
Scaled explained SS	1.070600	Prob. Chi-Square(2)	0.5855

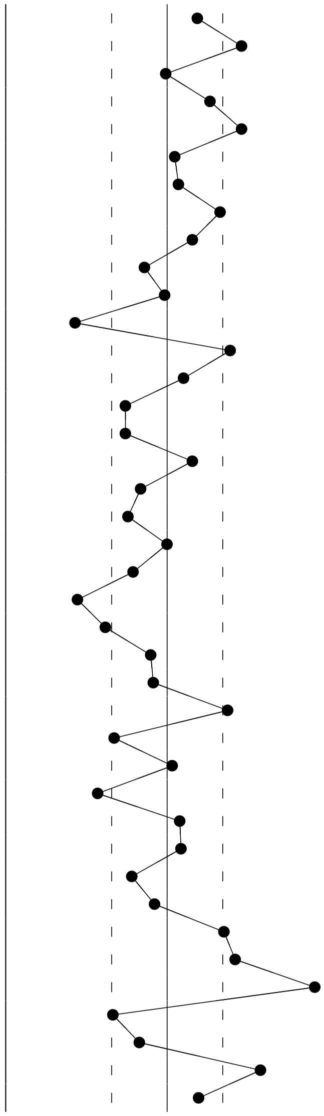
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 15:43
Sample: 2010M12 2014M03
Included observations: 40

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	9258.451	7579.818	1.221461	0.2296
EDD_BC	0.672168	1.212652	0.554296	0.5827
HLF_PRICE	-670.8096	692.6564	-0.968459	0.3391

R-squared	0.032874	Mean dependent var	2402.195
Adjusted R-squared	-0.019403	S.D. dependent var	3547.909
S.E. of regression	3582.164	Akaike info criterion	19.27736
Sum squared resid	4.75E+08	Schwarz criterion	19.40403
Log likelihood	-382.5472	Hannan-Quinn criter.	19.32316
F-statistic	0.628835	Durbin-Watson stat	1.966958
Prob(F-statistic)	0.538814		

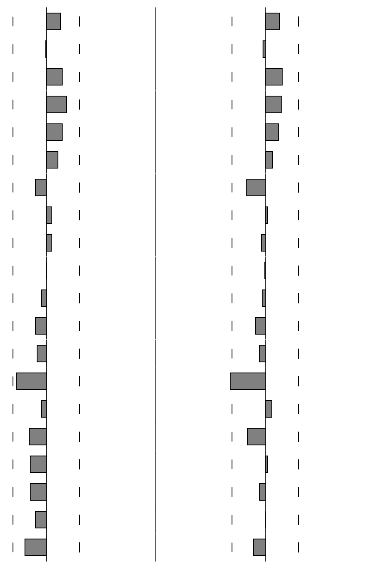
obs	Actual	Fitted	Residual
2010M12	1560.10	1531.74	28.3592
2011M01	1845.63	1775.00	70.6362
2011M02	1729.00	1730.63	-1.63255
2011M03	1652.83	1612.37	40.4581
2011M04	1336.77	1265.96	70.8071
2011M05	1078.41	1071.76	6.65199
2011M06	977.718	967.033	10.6842
2011M07	944.914	894.690	50.2243
2011M08	950.257	926.772	23.4858
2011M09	1012.07	1033.58	-21.5090
2011M10	1140.08	1142.71	-2.63679
2011M11	1343.18	1431.22	-88.0405
2011M12	1554.34	1494.22	60.1179
2012M01	1782.10	1766.32	15.7821
2012M02	1631.71	1670.91	-39.2060
2012M03	1560.88	1600.27	-39.3914
2012M04	1275.42	1251.00	24.4150
2012M05	1128.82	1154.15	-25.3247
2012M06	1016.39	1053.95	-37.5623
2012M07	998.527	998.796	-0.26898
2012M08	999.285	1032.15	-32.8616
2012M09	1043.84	1128.59	-84.7490
2012M10	1214.19	1272.99	-58.7922
2012M11	1532.18	1547.22	-15.0385
2012M12	1664.14	1677.69	-13.5586
2013M01	1941.91	1884.47	57.4373
2013M02	1802.72	1852.81	-50.0897
2013M03	1789.86	1785.02	4.84147
2013M04	1455.80	1521.31	-65.5092
2013M05	1368.83	1356.90	11.9370
2013M06	1252.98	1240.00	12.9738
2013M07	1132.75	1166.39	-33.6382
2013M08	1171.63	1183.62	-11.9824
2013M09	1316.86	1263.29	53.5662
2013M10	1441.85	1376.64	65.2125
2013M11	1770.63	1630.77	139.863
2013M12	1762.07	1813.51	-51.4361
2014M01	1991.97	2018.02	-26.0483
2014M02	1996.09	1907.42	88.6692
2014M03	1901.78	1872.12	29.6582

Residual Plot



Correlogram of Residuals

Date: 01/06/15 Time: 15:43
Sample: 2010M12 2014M03
Included observations: 40
Q-statistic probabilities adjusted for 2 ARMA term(s)



Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	0.133	0.133	0.7574	
		2	-0.003	-0.021	0.7578	
		3	0.152	0.158	1.8059	0.179
		4	0.191	0.155	3.5089	0.173
		5	0.153	0.125	4.6356	0.201
		6	0.109	0.073	5.2245	0.265
		7	-0.104	-0.175	5.7780	0.328
		8	0.050	0.018	5.9072	0.434
		9	0.054	-0.038	6.0677	0.532
		10	0.004	-0.005	6.0685	0.640
		11	-0.045	-0.032	6.1841	0.721
		12	-0.104	-0.095	6.8385	0.741
		13	-0.083	-0.056	7.2687	0.777
		14	-0.280	-0.333	12.352	0.418
		15	-0.048	0.059	12.506	0.487
		16	-0.161	-0.167	14.311	0.427
		17	-0.150	0.023	15.958	0.385
		18	-0.153	-0.051	17.755	0.338
		19	-0.101	0.001	18.574	0.354
		20	-0.203	-0.110	22.045	0.230

Dependent Variable: N_LLF_C_S
Method: Least Squares
Date: 05/05/14 Time: 11:08
Sample (adjusted): 2009M12 2014M03
Included observations: 52 after adjustments
Convergence achieved after 11 iterations
MA Backcast: 2009M11

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EMPNM	7.842023	0.064297	121.9654	0.0000
SEP	26.55662	9.268400	2.865286	0.0067
OCT	107.4461	15.67142	6.856183	0.0000
NOV	143.2018	18.87045	7.588681	0.0000
DEC	162.7345	20.15909	8.072514	0.0000
JAN	160.7003	20.26904	7.928359	0.0000
FEB	145.3411	19.74765	7.359918	0.0000
MAR	116.7000	18.40387	6.341058	0.0000
APR	77.93639	15.32492	5.085598	0.0000
MAY	21.21416	9.165513	2.314564	0.0260
D_2013M12	-56.67191	11.52526	-4.917191	0.0000
AR(1)	0.889319	0.075552	11.77090	0.0000
MA(1)	0.496656	0.147481	3.367586	0.0017

R-squared	0.955704	Mean dependent var	4532.173
Adjusted R-squared	0.942074	S.D. dependent var	77.29818
S.E. of regression	18.60397	Akaike info criterion	8.896945
Sum squared resid	13498.20	Schwarz criterion	9.384756
Log likelihood	-218.3206	Hannan-Quinn criter.	9.083961
Durbin-Watson stat	2.139245		

Inverted AR Roots	.89
Inverted MA Roots	-.50

Variable Name	Definition
EMPNM	Non-Manufacturing Employment
SEP	September
OCT	October
NOV	November
DEC	December
JAN	January
FEB	February
MAR	March
APR	April
MAY	May
D_2013M12	Dummy, December 2013
AR(1)	Autoregressive Term, lag 1
MA(1)	Moving Average Term, lag 1

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	0.578787	Prob. F(11,40)	0.8344
Obs*R-squared	7.140175	Prob. Chi-Square(11)	0.7876
Scaled explained SS	3.523986	Prob. Chi-Square(11)	0.9818

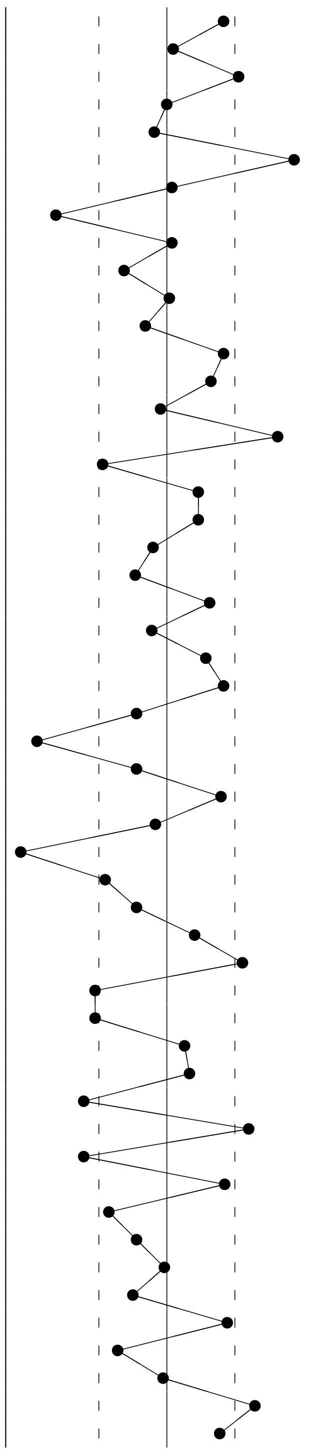
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 14:20
Sample: 2009M12 2014M03
Included observations: 52

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-2029.498	4444.264	-0.456656	0.6504
EMPNM	4.118136	7.856734	0.524154	0.6031
SEP	-221.3884	210.4370	-1.052041	0.2991
OCT	-177.7031	211.0421	-0.842027	0.4048
NOV	-111.5171	211.4377	-0.527423	0.6008
DEC	-18.96814	210.6701	-0.090037	0.9287
JAN	-255.9708	193.9834	-1.319550	0.1945
FEB	142.8136	194.2565	0.735180	0.4665
MAR	26.91881	194.7566	0.138218	0.8908
APR	-43.54556	210.2935	-0.207070	0.8370
MAY	146.3074	210.2838	0.695761	0.4906
D_2013M12	-156.2992	421.5003	-0.370816	0.7127

R-squared	0.137311	Mean dependent var	259.5809
Adjusted R-squared	-0.099928	S.D. dependent var	347.2207
S.E. of regression	364.1563	Akaike info criterion	14.83222
Sum squared resid	5304393.	Schwarz criterion	15.28250
Log likelihood	-373.6377	Hannan-Quinn criter.	15.00485
F-statistic	0.578787	Durbin-Watson stat	2.549552
Prob(F-statistic)	0.834397		

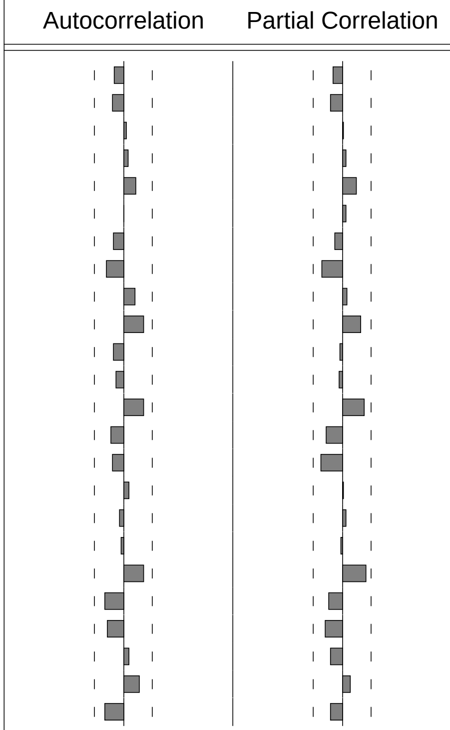
obs	Actual	Fitted	Residual
2009M12	4606.00	4590.53	15.4659
2010M01	4596.00	4594.30	1.70379
2010M02	4599.00	4579.39	19.6125
2010M03	4579.00	4579.07	-0.07241
2010M04	4541.00	4544.55	-3.54730
2010M05	4509.00	4474.34	34.6561
2010M06	4492.00	4490.60	1.40443
2010M07	4445.00	4475.15	-30.1534
2010M08	4425.00	4423.49	1.51127
2010M09	4439.00	4450.66	-11.6609
2010M10	4514.00	4513.48	0.52150
2010M11	4545.00	4550.71	-5.71127
2010M12	4578.00	4562.70	15.3000
2011M01	4595.00	4583.08	11.9232
2011M02	4583.00	4584.55	-1.55108
2011M03	4582.00	4551.98	30.0188
2011M04	4540.00	4557.57	-17.5701
2011M05	4474.00	4465.59	8.41140
2011M06	4457.00	4448.31	8.69123
2011M07	4441.00	4444.79	-3.78947
2011M08	4431.00	4439.71	-8.71254
2011M09	4471.00	4459.38	11.6226
2011M10	4560.00	4564.17	-4.17180
2011M11	4608.00	4597.53	10.4734
2011M12	4649.00	4633.69	15.3073
2012M01	4648.00	4656.15	-8.14597
2012M02	4591.00	4626.16	-35.1555
2012M03	4539.00	4547.28	-8.27678
2012M04	4515.00	4500.19	14.8091
2012M05	4468.00	4470.97	-2.97000
2012M06	4411.00	4450.93	-39.9325
2012M07	4384.00	4400.69	-16.6910
2012M08	4382.00	4390.21	-8.21283
2012M09	4427.00	4419.32	7.67681
2012M10	4548.00	4527.43	20.5706
2012M11	4581.00	4600.53	-19.5320
2012M12	4578.00	4597.64	-19.6423
2013M01	4578.00	4573.10	4.89604
2013M02	4585.00	4578.82	6.18387
2013M03	4549.00	4571.49	-22.4906
2013M04	4541.00	4518.82	22.1792
2013M05	4475.00	4497.59	-22.5900
2013M06	4460.00	4444.07	15.9275
2013M07	4444.00	4459.88	-15.8794
2013M08	4441.00	4449.13	-8.13363
2013M09	4481.00	4481.75	-0.75458
2013M10	4575.00	4584.17	-9.16932
2013M11	4633.00	4616.43	16.5662
2013M12	4596.00	4609.20	-13.1998
2014M01	4644.00	4645.07	-1.06711
2014M02	4665.00	4640.86	24.1442
2014M03	4675.00	4660.67	14.3287

Residual Plot



Correlogram of Residuals

Date: 01/06/15 Time: 14:20
Sample: 2009M12 2014M03
Included observations: 52
Q-statistic probabilities adjusted for 2 ARMA term(s)



	AC	PAC	Q-Stat	Prob
1	-0.086	-0.086	0.4104	
2	-0.106	-0.114	1.0432	
3	0.030	0.010	1.0931	0.296
4	0.044	0.036	1.2063	0.547
5	0.121	0.136	2.0880	0.554
6	0.002	0.036	2.0882	0.720
7	-0.096	-0.070	2.6669	0.751
8	-0.157	-0.189	4.2497	0.643
9	0.113	0.049	5.0813	0.650
10	0.191	0.179	7.5227	0.481
11	-0.093	-0.018	8.1175	0.522
12	-0.073	-0.030	8.4903	0.581
13	0.195	0.210	11.216	0.425
14	-0.121	-0.148	12.294	0.422
15	-0.101	-0.200	13.074	0.442
16	0.054	0.009	13.301	0.503
17	-0.036	0.040	13.406	0.571
18	-0.024	-0.012	13.454	0.639
19	0.195	0.225	16.676	0.477
20	-0.174	-0.130	19.344	0.371
21	-0.148	-0.163	21.318	0.319
22	0.055	-0.113	21.601	0.363
23	0.153	0.074	23.858	0.300
24	-0.174	-0.109	26.905	0.215

Dependent Variable: N_LLF_UPC_S
Method: Least Squares
Date: 05/05/14 Time: 12:08
Sample (adjusted): 2010M01 2014M03
Included observations: 51 after adjustments
Convergence achieved after 15 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_BC	0.358140	0.025661	13.95669	0.0000
C	22.02062	10.49147	2.098907	0.0413
EDD_BC*(NOV+DEC+JAN+FEB+MAR)	0.267057	0.035262	7.573550	0.0000
LLF_PRICE*(NOV+DEC+JAN+FEB+MA	-13.72220	1.990443	-6.894043	0.0000
AR(1)	0.330448	0.155727	2.121975	0.0393

R-squared	0.984618	Mean dependent var	274.7946
Adjusted R-squared	0.983281	S.D. dependent var	226.7926
S.E. of regression	29.32495	Akaike info criterion	9.687649
Sum squared resid	39557.83	Schwarz criterion	9.877043
Log likelihood	-242.0350	Hannan-Quinn criter.	9.760022
F-statistic	736.1413	Durbin-Watson stat	2.051751
Prob(F-statistic)	0.000000		
Inverted AR Roots	.33		

Variable Name	Definition
EDD_BC	Bill Cycle EDD
C	Constant
EDD_BC*(NOV+DEC+JAN+FEB+MAR)	Interaction Variable - Bill Cycle EDD * November - March
LLF_PRICE*(NOV+DEC+JAN+FEB+MAR)	Interaction Variable - LLF Natural Gas Price * November - March
AR(1)	Autoregressive Term, lag 1

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	2.126104	Prob. F(3,47)	0.1095
Obs*R-squared	6.094122	Prob. Chi-Square(3)	0.1071
Scaled explained SS	4.319162	Prob. Chi-Square(3)	0.2290

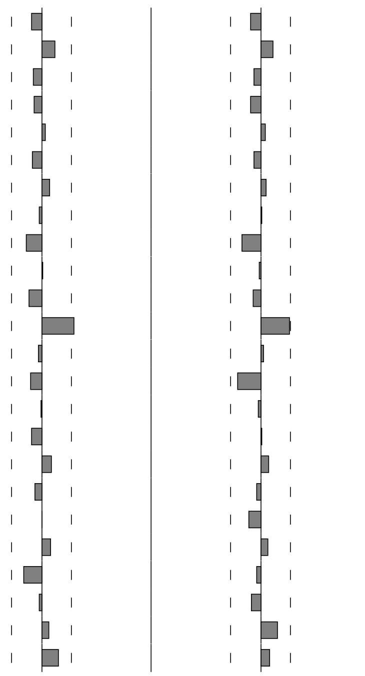
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 14:30
Sample: 2010M01 2014M03
Included observations: 51

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	263.6541	262.1483	1.005744	0.3197
EDD_BC	1.023835	0.775620	1.320022	0.1932
EDD_BC*(NOV+DEC+JAN+FEB+MAR)	-0.830567	1.084168	-0.766087	0.4475
LLF_PRICE*(NOV+DEC+JAN+FEB+MA	46.25101	61.92976	0.746830	0.4589

R-squared	0.119493	Mean dependent var	775.6437
Adjusted R-squared	0.063290	S.D. dependent var	1034.032
S.E. of regression	1000.775	Akaike info criterion	16.73012
Sum squared resid	47072882	Schwarz criterion	16.88164
Log likelihood	-422.6181	Hannan-Quinn criter.	16.78802
F-statistic	2.126104	Durbin-Watson stat	1.937337
Prob(F-statistic)	0.109514		

Correlogram of Residuals

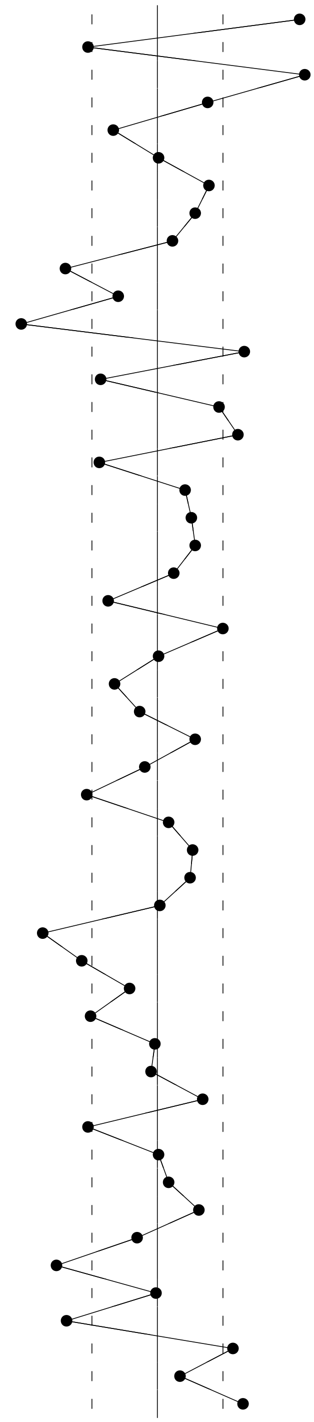
Date: 01/06/15 Time: 14:30
Sample: 2010M01 2014M03
Included observations: 51
Q-statistic probabilities adjusted for 1 ARMA term(s)



Lag	AC	PAC	Q-Stat	Prob
1	-0.097	-0.097	0.5059	
2	0.129	0.120	1.4178	0.234
3	-0.079	-0.058	1.7670	0.413
4	-0.067	-0.096	2.0217	0.568
5	0.040	0.045	2.1144	0.715
6	-0.083	-0.063	2.5326	0.772
7	0.081	0.049	2.9385	0.817
8	-0.020	0.009	2.9637	0.888
9	-0.147	-0.177	4.3596	0.823
10	0.014	-0.011	4.3729	0.885
11	-0.120	-0.070	5.3513	0.867
12	0.309	0.279	11.982	0.365
13	-0.026	0.030	12.029	0.443
14	-0.100	-0.216	12.759	0.467
15	-0.004	-0.022	12.760	0.545
16	-0.096	0.011	13.467	0.566
17	0.096	0.076	14.201	0.584
18	-0.064	-0.037	14.534	0.629
19	0.003	-0.110	14.535	0.694
20	0.088	0.072	15.206	0.709
21	-0.169	-0.041	17.789	0.601
22	-0.023	-0.083	17.840	0.659
23	0.071	0.158	18.332	0.686
24	0.160	0.084	20.893	0.588

obs	Actual	Fitted	Residual
2010M01	699.550	635.439	64.1106
2010M02	577.576	609.009	-31.4331
2010M03	437.971	371.931	66.0398
2010M04	282.159	259.539	22.6202
2010M05	151.921	171.878	-19.9570
2010M06	67.2322	66.4111	0.82113
2010M07	51.7317	28.4987	23.2330
2010M08	47.9368	30.6644	17.2724
2010M09	52.7038	45.6295	7.07429
2010M10	82.2631	123.410	-41.1474
2010M11	199.857	217.577	-17.7197
2010M12	372.083	433.580	-61.4972
2011M01	640.599	601.470	39.1294
2011M02	659.030	684.500	-25.4700
2011M03	515.638	487.743	27.8951
2011M04	366.014	329.498	36.5155
2011M05	172.102	198.279	-26.1771
2011M06	101.390	89.0337	12.3561
2011M07	56.0002	40.9317	15.0686
2011M08	45.8573	28.6398	17.2175
2011M09	54.6054	47.2095	7.39581
2011M10	75.3249	97.1846	-21.8597
2011M11	204.635	174.981	29.6532
2011M12	295.868	295.573	0.29459
2012M01	508.231	527.386	-19.1551
2012M02	489.723	497.598	-7.87468
2012M03	395.518	378.556	16.9623
2012M04	235.652	241.415	-5.76313
2012M05	135.003	166.535	-31.5320
2012M06	73.3845	68.0111	5.37333
2012M07	47.7527	32.1136	15.6391
2012M08	41.5859	26.9764	14.6095
2012M09	45.3296	44.1257	1.20391
2012M10	73.5862	125.153	-51.5668
2012M11	186.357	220.550	-34.1930
2012M12	388.998	401.299	-12.3007
2013M01	525.568	555.509	-29.9409
2013M02	612.543	613.552	-1.00878
2013M03	486.506	489.433	-2.92658
2013M04	333.640	313.192	20.4476
2013M05	158.145	189.471	-31.3268
2013M06	81.7161	80.9585	0.75764
2013M07	36.7541	31.6745	5.07962
2013M08	46.7747	27.8794	18.8952
2013M09	44.6381	53.6135	-8.97535
2013M10	73.4598	118.624	-45.1645
2013M11	241.620	242.018	-0.39748
2013M12	481.788	522.745	-40.9567
2014M01	713.966	680.072	33.8938
2014M02	689.058	678.951	10.1068
2014M03	657.177	618.499	38.6775

Residual Plot



Dependent Variable: N_HLF_C_S
Method: Least Squares
Date: 05/05/14 Time: 10:51
Sample (adjusted): 2009M12 2014M03
Included observations: 52 after adjustments
Convergence achieved after 8 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EMPM	12.22154	3.183801	3.838664	0.0004
SEP	-11.29316	5.050395	-2.236095	0.0310
OCT	-44.07939	5.303560	-8.311282	0.0000
NOV	-47.41914	5.957540	-7.959516	0.0000
DEC	-50.28281	6.147712	-8.179109	0.0000
JAN	-51.86624	6.107517	-8.492198	0.0000
FEB	-52.42035	5.833432	-8.986194	0.0000
MAR	-48.33604	5.289522	-9.138074	0.0000
APR	-21.27995	4.028257	-5.282669	0.0000
D_2012M9	-27.34866	7.449113	-3.671398	0.0007
D_2013M9	11.31859	7.448183	1.519645	0.1365
AR(1)	0.983203	0.016760	58.66242	0.0000

R-squared	0.989177	Mean dependent var	977.5000
Adjusted R-squared	0.986200	S.D. dependent var	72.59652
S.E. of regression	8.528024	Akaike info criterion	7.323767
Sum squared resid	2909.088	Schwarz criterion	7.774054
Log likelihood	-178.4179	Hannan-Quinn criter.	7.496396
Durbin-Watson stat	1.714212		
Inverted AR Roots	.98		

Variable Name	Definition
EMPM	Manufacturing Employment
SEP	September
OCT	October
NOV	November
DEC	December
JAN	January
FEB	February
MAR	March
APR	April
D_2012M9	Dummy, September 2012
D_2013M9	Dummy, September 2013
AR(1)	Autoregressive Term, lag 1

Heteroskedasticity Test: Harvey

F-statistic	1.123786	Prob. F(11,40)	0.3692
Obs*R-squared	12.27626	Prob. Chi-Square(11)	0.3432
Scaled explained SS	12.83029	Prob. Chi-Square(11)	0.3046

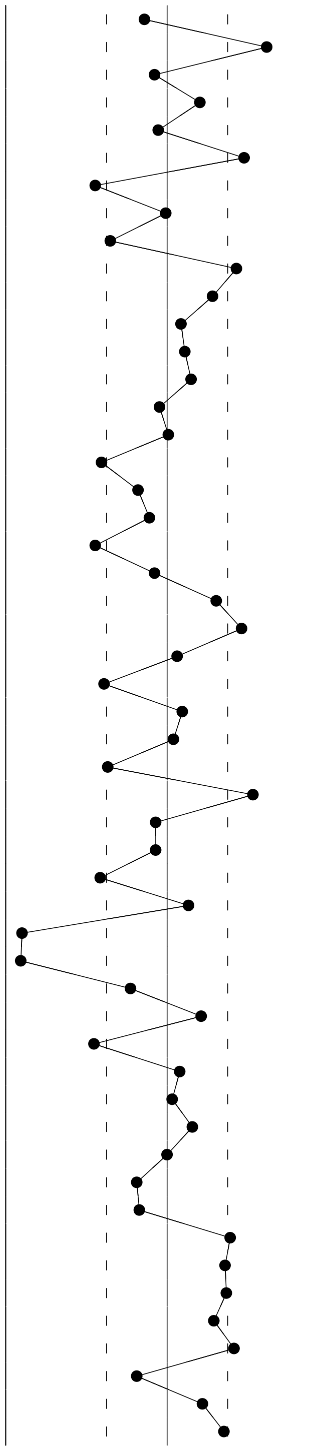
Test Equation:
Dependent Variable: LRESID2
Method: Least Squares
Date: 01/06/15 Time: 14:17
Sample: 2009M12 2014M03
Included observations: 52

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4.094189	61.13137	0.066974	0.9469
EMPM	-0.029627	0.924899	-0.032033	0.9746
SEP	2.059307	1.702175	1.209809	0.2335
OCT	2.528950	1.272690	1.987091	0.0538
NOV	0.092409	1.268764	0.072834	0.9423
DEC	1.094743	1.167077	0.938021	0.3539
JAN	1.205958	1.166272	1.034028	0.3073
FEB	-1.072396	1.162230	-0.922705	0.3617
MAR	-0.596316	1.159802	-0.514153	0.6100
APR	0.966117	1.268371	0.761699	0.4507
D_2012M9	1.803437	2.795525	0.645116	0.5225
D_2013M9	0.003534	2.784344	0.001269	0.9990

R-squared	0.236082	Mean dependent var	2.667929
Adjusted R-squared	0.026005	S.D. dependent var	2.293172
S.E. of regression	2.263159	Akaike info criterion	4.670575
Sum squared resid	204.8756	Schwarz criterion	5.120862
Log likelihood	-109.4349	Hannan-Quinn criter.	4.843204
F-statistic	1.123786	Durbin-Watson stat	2.182459
Prob(F-statistic)	0.369166		

obs	Actual	Fitted	Residual
2009M12	1050.00	1053.24	-3.24202
2010M01	1053.00	1039.03	13.9675
2010M02	1047.00	1048.80	-1.79521
2010M03	1053.00	1048.45	4.54964
2010M04	1077.00	1078.28	-1.28341
2010M05	1105.00	1094.26	10.7409
2010M06	1090.00	1100.10	-10.1050
2010M07	1085.00	1085.21	-0.21474
2010M08	1073.00	1080.94	-7.93783
2010M09	1068.00	1058.26	9.74448
2010M10	1038.00	1031.58	6.41746
2010M11	1033.00	1031.04	1.96088
2010M12	1029.00	1026.47	2.53196
2011M01	1027.00	1023.71	3.29339
2011M02	1022.00	1022.98	-0.98113
2011M03	1023.00	1022.77	0.22827
2011M04	1038.00	1047.12	-9.11964
2011M05	1052.00	1056.05	-4.05476
2011M06	1046.00	1048.40	-2.40313
2011M07	1034.00	1044.04	-10.0351
2011M08	1027.00	1028.79	-1.79427
2011M09	1017.00	1010.22	6.78400
2011M10	988.000	977.607	10.3934
2011M11	982.000	980.645	1.35525
2011M12	967.000	975.728	-8.72801
2012M01	965.000	962.859	2.14086
2012M02	961.000	960.116	0.88390
2012M03	952.000	960.354	-8.35369
2012M04	986.000	974.012	11.9879
2012M05	1002.00	1003.55	-1.54502
2012M06	997.000	998.651	-1.65132
2012M07	985.000	994.276	-9.27600
2012M08	984.000	980.930	3.07025
2012M09	921.000	941.149	-20.1494
2012M10	890.000	910.494	-20.4936
2012M11	880.000	885.056	-5.05648
2012M12	881.000	876.171	4.82870
2013M01	869.000	879.283	-10.2829
2013M02	868.000	866.158	1.84248
2013M03	870.000	869.317	0.68324
2013M04	897.000	893.452	3.54767
2013M05	917.000	916.921	0.07905
2013M06	912.000	916.173	-4.17298
2013M07	908.000	911.880	-3.88000
2013M08	915.000	906.259	8.74114
2013M09	921.000	912.821	8.17950
2013M10	882.000	873.681	8.31924
2013M11	884.000	877.544	6.45601
2013M12	890.000	880.594	9.40560
2014M01	883.000	887.241	-4.24071
2014M02	887.000	881.989	5.01146
2014M03	899.000	891.061	7.93881

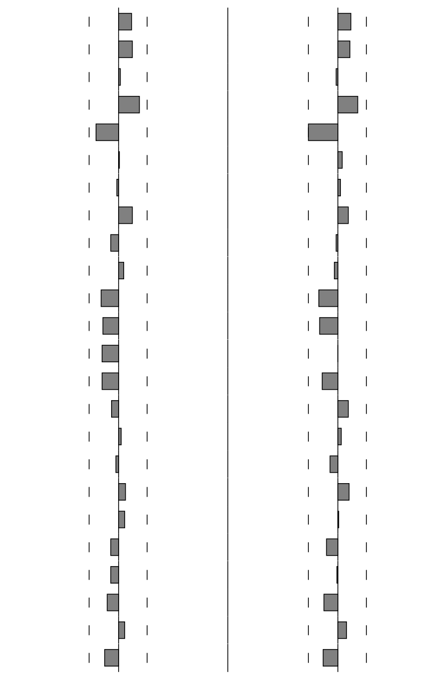
Residual Plot



Correlogram of Residuals

Date: 01/06/15 Time: 14:17
Sample: 2009M12 2014M03
Included observations: 52
Q-statistic probabilities adjusted for 1 ARMA term(s)

Autocorrelation | Partial Correlation



	AC	PAC	Q-Stat	Prob
1	0.130	0.130	0.9345	
2	0.134	0.119	1.9489	0.163
3	0.020	-0.012	1.9712	0.373
4	0.202	0.191	4.3550	0.226
5	-0.211	-0.276	7.0214	0.135
6	0.014	0.045	7.0339	0.218
7	-0.016	0.032	7.0498	0.316
8	0.136	0.101	8.2251	0.313
9	-0.072	-0.013	8.5630	0.380
10	0.056	-0.027	8.7708	0.459
11	-0.156	-0.174	10.444	0.402
12	-0.143	-0.168	11.881	0.373
13	-0.151	0.002	13.531	0.332
14	-0.148	-0.144	15.146	0.298
15	-0.064	0.100	15.453	0.348
16	0.032	0.038	15.535	0.414
17	-0.019	-0.069	15.564	0.484
18	0.072	0.110	15.993	0.524
19	0.064	0.012	16.342	0.569
20	-0.069	-0.105	16.756	0.606
21	-0.071	-0.005	17.216	0.639
22	-0.099	-0.127	18.131	0.641
23	0.060	0.083	18.477	0.677
24	-0.131	-0.138	20.197	0.630

Dependent Variable: N_HLF_UPC_S
Method: Least Squares
Date: 05/16/14 Time: 09:48
Sample (adjusted): 2010M12 2014M03
Included observations: 40 after adjustments
Convergence achieved after 17 iterations
MA Backcast: 2009M12 2010M11

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD_BC	0.180726	0.012732	14.19456	0.0000
HLF_PRICE	-17.41497	6.262959	-2.780631	0.0088
C	392.4079	45.14517	8.692135	0.0000
AR(12)	0.597939	0.149491	3.999836	0.0003
AR(6)	0.153382	0.124245	1.234506	0.2255
MA(12)	-0.869451	0.034939	-24.88488	0.0000

R-squared	0.978734	Mean dependent var	340.0654
Adjusted R-squared	0.975607	S.D. dependent var	82.78428
S.E. of regression	12.92946	Akaike info criterion	8.094375
Sum squared resid	5683.813	Schwarz criterion	8.347707
Log likelihood	-155.8875	Hannan-Quinn criter.	8.185972
F-statistic	312.9640	Durbin-Watson stat	2.171393
Prob(F-statistic)	0.000000		

Inverted AR Roots	.97	.82-.47i	.82+.47i	.49-.84i
	.49+.84i	-.00-.94i	-.00+.94i	-.49-.84i
	-.49+.84i	-.82+.47i	-.82-.47i	-.97
Inverted MA Roots	.99	.86+.49i	.86-.49i	.49+.86i
	.49-.86i	-.00-.99i	-.00+.99i	-.49-.86i
	-.49+.86i	-.86+.49i	-.86-.49i	-.99

Variable Name	Definition
EDD_BC	Bill Cycle EDD
HLF_PRICE	HLF Natural Gas Price
C	Constant
AR(12)	Autoregressive Term, lag 12
AR(6)	Autoregressive Term, lag 6
MA(12)	Moving Average Term, lag 12

Heteroskedasticity Test: Breusch-Pagan-Godfrey

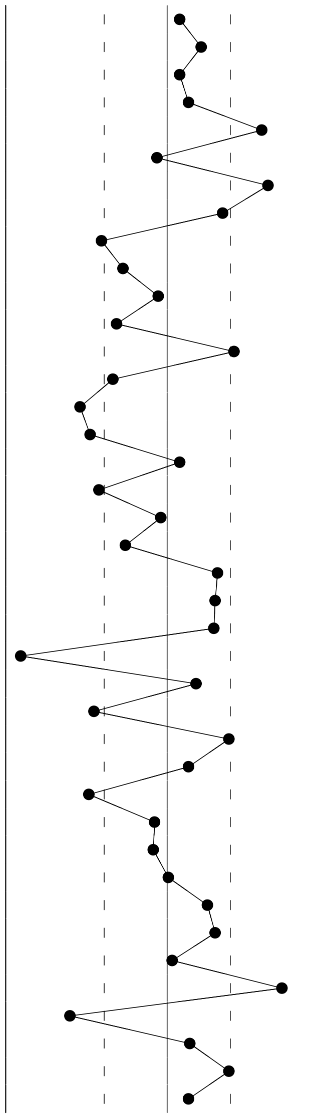
F-statistic	0.188398	Prob. F(2,37)	0.8291
Obs*R-squared	0.403240	Prob. Chi-Square(2)	0.8174
Scaled explained SS	0.231786	Prob. Chi-Square(2)	0.8906

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 15:42
Sample: 2010M12 2014M03
Included observations: 40

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	42.71194	392.3558	0.108860	0.9139
EDD_BC	0.036635	0.062771	0.583635	0.5630
HLF_PRICE	7.058651	35.85413	0.196871	0.8450

R-squared	0.010081	Mean dependent var	142.0953
Adjusted R-squared	-0.043428	S.D. dependent var	181.5246
S.E. of regression	185.4244	Akaike info criterion	13.35521
Sum squared resid	1272141.	Schwarz criterion	13.48188
Log likelihood	-264.1042	Hannan-Quinn criter.	13.40101
F-statistic	0.188398	Durbin-Watson stat	2.202386
Prob(F-statistic)	0.829075		

obs	Actual	Fitted	Residual	Residual Plot
2010M12	368.110	365.660	2.44976	
2011M01	470.155	463.241	6.91379	
2011M02	475.936	473.379	2.55706	
2011M03	408.034	403.699	4.33519	
2011M04	359.210	339.868	19.3426	
2011M05	271.465	273.601	-2.13687	
2011M06	271.281	250.619	20.6619	
2011M07	258.992	247.788	11.2038	
2011M08	241.614	254.953	-13.3387	
2011M09	265.433	274.297	-8.86404	
2011M10	248.350	250.140	-1.78996	
2011M11	313.386	323.679	-10.2931	
2011M12	348.456	334.962	13.4941	
2012M01	420.062	431.012	-10.9503	
2012M02	403.812	421.533	-17.7212	
2012M03	363.273	378.986	-15.7137	
2012M04	304.527	302.050	2.47654	
2012M05	263.609	277.423	-13.8148	
2012M06	240.147	241.338	-1.19078	
2012M07	228.533	236.952	-8.41996	
2012M08	256.277	245.961	10.3153	
2012M09	268.261	258.602	9.65917	
2012M10	277.968	268.589	9.37900	
2012M11	312.881	342.796	-29.9148	
2012M12	386.356	380.457	5.89912	
2013M01	433.773	448.588	-14.8154	
2013M02	484.354	471.884	12.4695	
2013M03	435.284	430.931	4.35295	
2013M04	360.263	376.121	-15.8581	
2013M05	315.138	317.765	-2.62673	
2013M06	270.440	273.262	-2.82212	
2013M07	257.016	256.753	0.26234	
2013M08	266.638	258.480	8.15815	
2013M09	276.779	266.947	9.83157	
2013M10	274.646	273.743	0.90213	
2013M11	377.439	354.107	23.3321	
2013M12	393.636	413.400	-19.7648	
2014M01	487.747	483.154	4.59356	
2014M02	485.310	472.752	12.5578	
2014M03	458.026	453.546	4.47976	



Correlogram of Residuals

Date: 01/06/15 Time: 15:41
Sample: 2010M12 2014M03
Included observations: 40
Q-statistic probabilities adjusted for 3 ARMA term(s)

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	-0.088	-0.088	0.3347	
		2	0.112	0.106	0.8940	
		3	-0.023	-0.005	0.9178	
		4	-0.002	-0.016	0.9180	0.338
		5	0.066	0.069	1.1268	0.569
		6	0.242	0.260	4.0094	0.260
		7	-0.286	-0.284	8.1737	0.085
		8	0.064	-0.026	8.3903	0.136
		9	-0.023	0.074	8.4183	0.209
		10	-0.165	-0.215	9.9480	0.192
		11	-0.044	-0.143	10.059	0.261
		12	-0.121	-0.089	10.939	0.280
		13	-0.016	0.142	10.954	0.361
		14	0.117	0.046	11.844	0.375
		15	0.043	0.081	11.969	0.448
		16	-0.128	-0.025	13.124	0.438
		17	0.011	-0.054	13.132	0.516
		18	-0.079	-0.061	13.605	0.556
		19	-0.094	-0.265	14.315	0.575
		20	0.023	-0.060	14.359	0.642

Dependent Variable: SC_ROL
Method: Least Squares
Date: 05/09/14 Time: 11:37
Sample (adjusted): 2011M10 2014M03
Included observations: 30 after adjustments
Convergence achieved after 17 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
HLF_PRICE(-6)	-1368.815	581.6764	-2.353224	0.0268
C	93778.38	8973.761	10.45029	0.0000
TREND	94.49328	56.03873	1.686214	0.1042
AR(1)	0.564926	0.103698	5.447781	0.0000
AR(12)	-0.162607	0.037170	-4.374659	0.0002

R-squared	0.987227	Mean dependent var	82950.06
Adjusted R-squared	0.985183	S.D. dependent var	2892.747
S.E. of regression	352.1200	Akaike info criterion	14.71683
Sum squared resid	3099712.	Schwarz criterion	14.95037
Log likelihood	-215.7525	Hannan-Quinn criter.	14.79154
F-statistic	483.0526	Durbin-Watson stat	1.694305
Prob(F-statistic)	0.000000		

Inverted AR Roots	.90-.21i	.90+.21i	.66-.59i	.66+.59i
	.27+.82i	.27-.82i	-.18+.82i	-.18-.82i
	-.57+.60i	-.57-.60i	-.79-.22i	-.79+.22i

Variable Name	Definition
HLF_PRICE(-6)	HLF Natural Gas Price, lagged 6 months
C	Constant
TREND	Linear Trend
AR(1)	Autoregressive Term, lag 1
AR(12)	Autoregressive Term, lag 12

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	0.185053	Prob. F(2,27)	0.8321
Obs*R-squared	0.405668	Prob. Chi-Square(2)	0.8164
Scaled explained SS	0.223949	Prob. Chi-Square(2)	0.8941

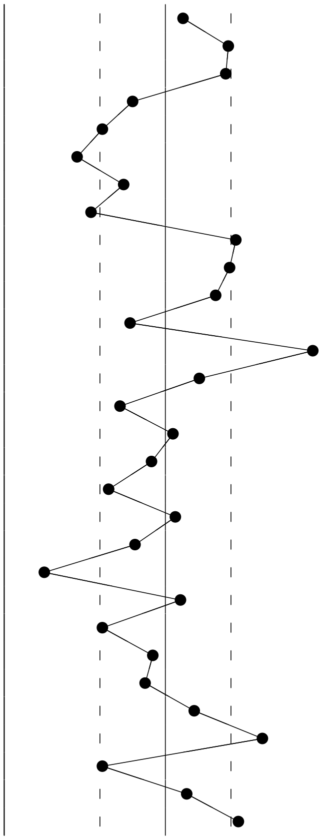
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/06/15 Time: 15:49
Sample: 2011M10 2014M03
Included observations: 30

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-735321.8	1473672.	-0.498973	0.6218
HLF_PRICE(-6)	56405.69	96098.94	0.586954	0.5621
TREND	4627.894	9133.707	0.506683	0.6165

R-squared	0.013522	Mean dependent var	103323.7
Adjusted R-squared	-0.059550	S.D. dependent var	132509.5
S.E. of regression	136398.0	Akaike info criterion	26.57918
Sum squared resid	5.02E+11	Schwarz criterion	26.71930
Log likelihood	-395.6877	Hannan-Quinn criter.	26.62401
F-statistic	0.185053	Durbin-Watson stat	2.394434
Prob(F-statistic)	0.832106		

obs	Actual	Fitted	Residual
2011M10	78662.1	78568.4	93.6798
2011M11	78433.9	78099.8	334.185
2011M12	78643.6	78324.7	318.899
2012M01	78350.6	78523.7	-173.074
2012M02	78338.2	78674.2	-336.015
2012M03	78551.8	79021.0	-469.185
2012M04	79269.2	79490.1	-220.926
2012M05	79651.4	80045.4	-393.978
2012M06	80920.8	80542.9	377.833
2012M07	81867.4	81524.4	343.049
2012M08	82640.4	82371.9	268.511
2012M09	82759.2	82949.3	-190.040
2012M10	83921.3	83139.4	781.872
2012M11	84131.5	83950.3	181.115
2012M12	83868.7	84109.7	-240.991
2013M01	84126.1	84084.2	41.9258
2013M02	84323.4	84396.2	-72.8384
2013M03	84273.0	84575.6	-302.620
2013M04	84609.3	84555.2	54.1383
2013M05	84607.3	84769.3	-162.050
2013M06	84170.8	84814.3	-643.504
2013M07	84756.8	84675.2	81.5606
2013M08	84758.8	85096.3	-337.538
2013M09	85277.0	85340.9	-63.8805
2013M10	85698.8	85805.8	-106.972
2013M11	86245.5	86090.9	154.627
2013M12	86763.7	86249.3	514.456
2014M01	86157.2	86489.9	-332.760
2014M02	86198.5	86084.4	114.103
2014M03	86525.4	86138.9	386.418

Residual Plot



Correlogram of Residuals

Date: 01/06/15 Time: 15:49
Sample: 2011M10 2014M03
Included observations: 30
Q-statistic probabilities adjusted for 2 ARMA term(s)

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	0.127	0.127	0.5368	
		2	0.026	0.010	0.5604	
		3	0.124	0.121	1.1069	0.293
		4	-0.103	-0.138	1.4973	0.473
		5	-0.292	-0.276	4.7617	0.190
		6	-0.197	-0.163	6.3208	0.176
		7	-0.135	-0.074	7.0815	0.215
		8	-0.173	-0.101	8.3924	0.211
		9	-0.148	-0.161	9.3903	0.226
		10	-0.027	-0.119	9.4252	0.308
		11	0.045	-0.051	9.5257	0.390
		12	-0.111	-0.246	10.184	0.424
		13	0.167	0.041	11.756	0.382
		14	0.101	-0.107	12.362	0.417
		15	-0.034	-0.167	12.435	0.492
		16	0.190	0.055	14.905	0.385

Dependent Variable: PERCENT_EXEMPT
Method: Least Squares
Date: 05/09/14 Time: 14:01
Sample (adjusted): 2011M10 2014M03
Included observations: 30 after adjustments
Convergence achieved after 5 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
NOV	-0.072796	0.012701	-5.731588	0.0000
MAY	-0.086716	0.016345	-5.305216	0.0000
MAR	-0.144906	0.014690	-9.864153	0.0000
JUN	-0.025148	0.014802	-1.698965	0.1056
JAN	-0.162714	0.014739	-11.03986	0.0000
FEB	-0.177126	0.014873	-11.90924	0.0000
DEC	-0.125022	0.014343	-8.716868	0.0000
APR	-0.136548	0.016769	-8.143029	0.0000
C	0.634122	0.008995	70.49332	0.0000
AR(1)	0.415504	0.202331	2.053585	0.0540
AR(12)	-0.209006	0.202340	-1.032944	0.3146

R-squared	0.937520	Mean dependent var	0.549661
Adjusted R-squared	0.904636	S.D. dependent var	0.073981
S.E. of regression	0.022846	Akaike info criterion	-4.443510
Sum squared resid	0.009917	Schwarz criterion	-3.929738
Log likelihood	77.65265	Hannan-Quinn criter.	-4.279150
F-statistic	28.50993	Durbin-Watson stat	2.126896
Prob(F-statistic)	0.000000		

Inverted AR Roots	.89-.22i	.89+.22i	.66-.61i	.66+.61i
	.26+.84i	.26-.84i	-.20-.84i	-.20+.84i
	-.59+.62i	-.59-.62i	-.82-.23i	-.82+.23i

Variable Name	Definition
NOV	November
MAY	May
MAR	March
JUN	June
JAN	January
FEB	February
DEC	December
APR	April
C	Constant
AR(1)	Autoregressive Term, lag 1
AR(12)	Autoregressive Term, lag 12

Heteroskedasticity Test: Breusch-Pagan-Godfrey

F-statistic	0.388415	Prob. F(8,21)	0.9147
Obs*R-squared	3.866855	Prob. Chi-Square(8)	0.8689
Scaled explained SS	2.948757	Prob. Chi-Square(8)	0.9375

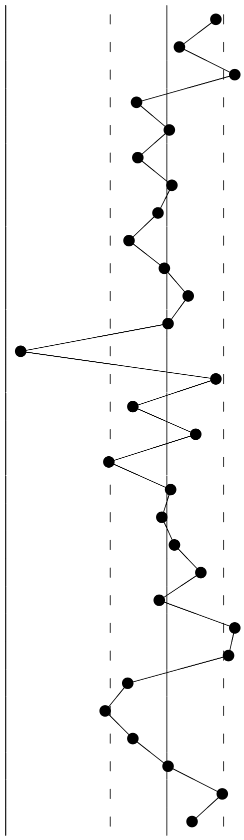
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 01/08/15 Time: 15:03
Sample: 2011M10 2014M03
Included observations: 30

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.000629	0.000240	2.623055	0.0159
NOV	-0.000280	0.000479	-0.583532	0.5658
MAY	-0.000619	0.000562	-1.101343	0.2832
MAR	-0.000547	0.000479	-1.141817	0.2664
JUN	-0.000412	0.000562	-0.733199	0.4715
JAN	-0.000532	0.000479	-1.109458	0.2798
FEB	-0.000269	0.000479	-0.561455	0.5804
DEC	-0.000249	0.000479	-0.519867	0.6086
APR	-0.000625	0.000562	-1.111963	0.2787

R-squared	0.128895	Mean dependent var	0.000331
Adjusted R-squared	-0.202954	S.D. dependent var	0.000656
S.E. of regression	0.000719	Akaike info criterion	-11.39395
Sum squared resid	1.09E-05	Schwarz criterion	-10.97359
Log likelihood	179.9093	Hannan-Quinn criter.	-11.25947
F-statistic	0.388415	Durbin-Watson stat	2.239581
Prob(F-statistic)	0.914675		

obs	Actual	Fitted	Residual
2011M10	0.66557	0.64550	0.02007
2011M11	0.57405	0.56891	0.00514
2011M12	0.53760	0.51005	0.02755
2012M01	0.46649	0.47875	-0.01226
2012M02	0.45925	0.45837	0.00089
2012M03	0.47692	0.48871	-0.01179
2012M04	0.49709	0.49526	0.00183
2012M05	0.54395	0.54728	-0.00333
2012M06	0.59508	0.61047	-0.01539
2012M07	0.63044	0.63155	-0.00111
2012M08	0.63595	0.62730	0.00865
2012M09	0.62671	0.62628	0.00043
2012M10	0.56487	0.62447	-0.05960
2012M11	0.54976	0.52989	0.01987
2012M12	0.48436	0.49834	-0.01398
2013M01	0.47399	0.46216	0.01183
2013M02	0.43393	0.45760	-0.02366
2013M03	0.48382	0.48221	0.00162
2013M04	0.49344	0.49543	-0.00199
2013M05	0.54927	0.54641	0.00286
2013M06	0.62667	0.61265	0.01401
2013M07	0.63936	0.64224	-0.00289
2013M08	0.66332	0.63592	0.02740
2013M09	0.67269	0.64780	0.02489
2013M10	0.64887	0.66462	-0.01575
2013M11	0.54486	0.56987	-0.02501
2013M12	0.49386	0.50743	-0.01357
2014M01	0.46496	0.46453	0.00042
2014M02	0.48189	0.45914	0.02276
2014M03	0.51081	0.50069	0.01012

Residual Plot



Correlogram of Residuals

Date: 01/08/15 Time: 15:03
Sample: 2011M10 2014M03
Included observations: 30
Q-statistic probabilities adjusted for 2 ARMA term(s)

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	-0.089	-0.089	0.2617	
		2	0.063	0.056	0.3980	
		3	-0.276	-0.269	3.1136	0.078
		4	0.091	0.050	3.4208	0.181
		5	-0.012	0.025	3.4262	0.330
		6	-0.059	-0.151	3.5648	0.468
		7	0.045	0.081	3.6499	0.601
		8	-0.042	-0.033	3.7275	0.713
		9	0.203	0.151	5.6128	0.586
		10	-0.269	-0.230	9.0975	0.334
		11	-0.096	-0.185	9.5646	0.387
		12	-0.154	-0.056	10.831	0.371
		13	0.241	0.111	14.123	0.226
		14	-0.088	-0.134	14.583	0.265
		15	-0.038	-0.096	14.675	0.328
		16	-0.156	-0.134	16.341	0.293

Dependent Variable: NH
Method: Least Squares
Date: 06/19/14 Time: 14:46
Sample (adjusted): 11/09/2012 3/31/2014
Included observations: 508 after adjustments
Convergence achieved after 17 iterations
MA Backcast: 11/08/2012

Variable	Coefficient	Std. Error	t-Statistic	Prob.
WEEKDAY_1	6165.057	1039.246	5.932243	0
WEEKDAY_2	8795.06	1040.813	8.45018	0
WEEKDAY_3	9454.021	1042.952	9.064678	0
WEEKDAY_4	9492.769	1044.258	9.09044	0
WEEKDAY_5	9223.758	1044.388	8.831736	0
WEEKDAY_6	7842.627	1041.672	7.528883	0
WEEKDAY_7	5644.056	1037.974	5.437569	0
EDD_NH	527.983	10.42798	50.63139	0
EDD_NH(-1)	149.6184	10.46267	14.30021	0
DEC	1042.494	550.0699	1.895202	0.0587
JAN	2145.167	651.5463	3.292424	0.0011
FEB	1276.283	556.6108	2.292954	0.0223
AR(1)	1.296476	0.066131	19.60475	0
AR(7)	0.028397	0.026216	1.083165	0.2793
AR(2)	-0.33451	0.052732	-6.34355	0
MA(1)	-0.879272	0.051078	-17.21424	0

R-squared	0.983885	Mean dependent var	24708.77
Adjusted R-squared	0.983393	S.D. dependent var	12116.6
S.E. of regression	1561.42	Akaike info criterion	17.57557
Sum squared resid	1.20E+09	Schwarz criterion	17.70881
Log likelihood	-4448.194	Hannan-Quinn criter.	17.62782
Durbin-Watson stat	1.980031		

Inverted AR Roots		0.99	.56-.36i	.56+.36i	.01+.53i
	.01-.53i		-.41-.24i	-.41+.24i	
Inverted MA Roots		0.88			

OUTLINE OF APPENDIX 2

Supplemental Materials for the Planning Load Forecast Section

Description of Materials

The materials in Appendix 2 supplement the materials presented in Section V, Planning Load Forecast.

In calculating Planning Load it was first necessary to define system throughput by customer segment. The first three sets of tables presented below demonstrate the calculation of throughput by the Residential, C&I Sales and C&I Transportation customer segments for Normal Year, Design Year and Design Day throughput, for both the Maine Division and the New Hampshire Division. Ratios, or contribution percentages, of demand by each customer segment to total demand were determined and then applied to the throughput values to determine throughput by customer segment. Effectively, this allocates the adjustments for Company Use and Losses and Unbilled Sales made to convert demand values to throughput values to each customer segment. The Normal Year Throughput values were calculated using contribution percentages based on the normal year demand forecast. The Design Year and Design Day Throughput values were determined using contribution percentages based on the design year demand forecast.

The customer segment throughput values were then used as inputs into the Long-Term Planning Load and Short-Term Planning Load calculations. The rationale and methods of calculation for these separate versions of planning load, as well as for the illustrative Alternative Planning Load version, are provided in Section V. Calculations of the three versions of planning load are provided in Section V for Design Year and Design Day. The Normal Year calculations are presented in this Appendix 2.

Normal Year Throughput by Customer Segment

Table A2-1: Normal Year Contribution Percentages by Segment (Dth) - Maine Division

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	System Demand	Residential Contribution	C&I Sales Contribution	C&I Transport Contribution
2014/15	1,502,014	2,583,723	7,373,291	11,459,029	13.1%	22.5%	64.3%
2015/16	1,580,416	2,700,552	7,428,541	11,709,510	13.5%	23.1%	63.4%
2016/17	1,686,769	2,794,378	7,869,100	12,350,247	13.7%	22.6%	63.7%
2017/18	1,805,170	2,872,379	8,394,068	13,071,616	13.8%	22.0%	64.2%
2018/19	1,923,796	2,938,536	8,822,232	13,684,564	14.1%	21.5%	64.5%
2019/20	2,020,478	2,989,477	8,834,874	13,844,829	14.6%	21.6%	63.8%

Table A2-2: Normal Year Contribution Percentages by Segment (Dth) - New Hampshire Division

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	System Demand	Residential Contribution	C&I Sales Contribution	C&I Transport Contribution
2014/15	1,751,143	1,858,297	3,200,002	6,809,441	25.7%	27.3%	47.0%
2015/16	1,771,327	1,832,876	3,262,985	6,867,188	25.8%	26.7%	47.5%
2016/17	1,801,737	1,841,162	3,372,825	7,015,724	25.7%	26.2%	48.1%
2017/18	1,836,484	1,862,228	3,491,548	7,190,260	25.5%	25.9%	48.6%
2018/19	1,871,730	1,875,235	3,585,834	7,332,798	25.5%	25.6%	48.9%
2019/20	1,900,560	1,857,364	3,607,345	7,365,269	25.8%	25.2%	49.0%

Table A2-3: Normal Year Throughput by Customer Segment (Dth) - Maine Division

Split Year	Normal Year Throughput	Residential Contribution	C&I Sales Contribution	C&I Transport Contribution	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput
2014/15	11,691,183	13.1%	22.5%	64.3%	1,532,444	2,636,068	7,522,670
2015/16	11,946,623	13.5%	23.1%	63.4%	1,612,419	2,755,237	7,578,966
2016/17	12,600,047	13.7%	22.6%	63.7%	1,720,886	2,850,898	8,028,263
2017/18	13,335,699	13.8%	22.0%	64.2%	1,841,639	2,930,409	8,563,651
2018/19	13,960,784	14.1%	21.5%	64.5%	1,962,627	2,997,850	9,000,307
2019/20	14,124,222	14.6%	21.6%	63.8%	2,061,252	3,049,806	9,013,164
CAGR	3.9%				6.1%	3.0%	3.7%

Table A2-4: Normal Year Throughput by Customer Segment (Dth) - New Hampshire Division

Split Year	Normal Year Throughput	Residential Contribution	C&I Sales Contribution	C&I Transport Contribution	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput
2014/15	6,854,468	25.7%	27.3%	47.0%	1,762,722	1,870,584	3,221,162
2015/16	6,912,578	25.8%	26.7%	47.5%	1,783,035	1,844,991	3,284,552
2016/17	7,062,050	25.7%	26.2%	48.1%	1,813,634	1,853,319	3,395,096
2017/18	7,237,686	25.5%	25.9%	48.6%	1,848,597	1,874,511	3,514,578
2018/19	7,381,122	25.5%	25.6%	48.9%	1,884,065	1,887,593	3,609,464
2019/20	7,413,797	25.8%	25.2%	49.0%	1,913,083	1,869,601	3,631,113
CAGR	1.6%				1.7%	0.0%	2.4%

Design Year Throughput by Customer Segment

Table A2-5: Design Year Contribution Percentages by Segment (Dth) - Maine Division

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	System Demand	Residential Contribution	C&I Sales Contribution	C&I Transport Contribution
2014/15	1,586,055	2,738,916	7,641,865	11,966,837	13.3%	22.9%	63.9%
2015/16	1,667,816	2,863,688	7,706,347	12,237,852	13.6%	23.4%	63.0%
2016/17	1,777,620	2,963,628	8,154,100	12,895,347	13.8%	23.0%	63.2%
2017/18	1,899,594	3,046,547	8,684,961	13,631,103	13.9%	22.3%	63.7%
2018/19	2,021,885	3,116,848	9,118,065	14,256,798	14.2%	21.9%	64.0%
2019/20	2,122,232	3,171,253	9,134,801	14,428,285	14.7%	22.0%	63.3%

Table A2-6: Design Year Contribution Percentages by Segment (Dth) - New Hampshire Division

Split Year	Residential Demand	C&I Sales Demand	C&I Transport Demand	System Demand	Residential Contribution	C&I Sales Contribution	C&I Transport Contribution
2014/15	1,841,617	1,978,400	3,285,219	7,105,236	25.9%	27.8%	46.2%
2015/16	1,861,248	1,950,969	3,348,436	7,160,653	26.0%	27.2%	46.8%
2016/17	1,892,966	1,959,671	3,459,952	7,312,588	25.9%	26.8%	47.3%
2017/18	1,929,080	1,981,113	3,580,050	7,490,243	25.8%	26.4%	47.8%
2018/19	1,965,763	1,994,073	3,675,275	7,635,111	25.7%	26.1%	48.1%
2019/20	1,996,162	1,975,863	3,697,282	7,669,306	26.0%	25.8%	48.2%

Table A2-7: Design Year Throughput by Customer Segment (Dth) - Maine Division

Split Year	Design Year Throughput	Residential Contribution	C&I Sales Contribution	C&I Transport Contribution	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput
2014/15	12,209,217	13.3%	22.9%	63.9%	1,618,180	2,794,391	7,796,646
2015/16	12,485,598	13.6%	23.4%	63.0%	1,701,580	2,921,662	7,862,357
2016/17	13,156,112	13.8%	23.0%	63.2%	1,813,566	3,023,557	8,318,989
2017/18	13,906,435	13.9%	22.3%	63.7%	1,937,964	3,108,084	8,860,387
2018/19	14,544,520	14.2%	21.9%	64.0%	2,062,689	3,179,751	9,302,080
2019/20	14,719,402	14.7%	22.0%	63.3%	2,165,052	3,235,239	9,319,112
CAGR	3.8%				6.0%	3.0%	3.6%

Table A2-8: Design Year Throughput by Customer Segment (Dth) - New Hampshire Division

Split Year	Design Year Throughput	Residential Contribution	C&I Sales Contribution	C&I Transport Contribution	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput
2014/15	7,152,237	25.9%	27.8%	46.2%	1,853,800	1,991,487	3,306,951
2015/16	7,208,003	26.0%	27.2%	46.8%	1,873,555	1,963,870	3,370,578
2016/17	7,360,896	25.9%	26.8%	47.3%	1,905,471	1,972,616	3,482,808
2017/18	7,539,670	25.8%	26.4%	47.8%	1,941,809	1,994,186	3,603,674
2018/19	7,685,450	25.7%	26.1%	48.1%	1,978,724	2,007,220	3,699,506
2019/20	7,719,861	26.0%	25.8%	48.2%	2,009,320	1,988,887	3,721,654
CAGR	1.5%				1.6%	0.0%	2.4%

Design Day Throughput by Customer Segment

Table A2-9: Design Day Throughput by Customer Segment (Dth) - Maine Division

Split Day	Design Day Throughput	Residential Contribution	C&I Sales Contribution	C&I Transport Contribution	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput
2014/15	83,737	13.3%	22.9%	63.9%	11,098	19,165	53,474
2015/16	85,633	13.6%	23.4%	63.0%	11,670	20,038	53,924
2016/17	90,232	13.8%	23.0%	63.2%	12,438	20,737	57,056
2017/18	95,378	13.9%	22.3%	63.7%	13,292	21,317	60,769
2018/19	99,754	14.2%	21.9%	64.0%	14,147	21,808	63,799
2019/20	100,954	14.7%	22.0%	63.3%	14,849	22,189	63,916
CAGR	3.8%				6.0%	3.0%	3.6%

Table A2-10: Design Day Throughput by Customer Segment (Dth) - New Hampshire Division

Split Day	Design Day Throughput	Residential Contribution	C&I Sales Contribution	C&I Transport Contribution	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput
2014/15	63,919	25.9%	27.8%	46.2%	16,567	17,798	29,554
2015/16	64,417	26.0%	27.2%	46.8%	16,744	17,551	30,122
2016/17	65,783	25.9%	26.8%	47.3%	17,029	17,629	31,125
2017/18	67,381	25.8%	26.4%	47.8%	17,354	17,822	32,206
2018/19	68,684	25.7%	26.1%	48.1%	17,684	17,938	33,062
2019/20	68,991	26.0%	25.8%	48.2%	17,957	17,774	33,260
CAGR	1.5%				1.6%	0.0%	2.4%

Normal Year Long-Term Planning Load

Table A2-11: Normal Year Long-Term Planning Load (Dth) - Maine Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Res + Cap Ass
Split Year	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Long-Term Planning Load
2014/15	1,532,444	2,636,068	7,522,670	10,158,738	1,613,411	4,272,664	4,272,664	5,805,108
2015/16	1,612,419	2,755,237	7,578,966	10,334,204	1,788,876	4,272,664	4,272,664	5,885,083
2016/17	1,720,886	2,850,898	8,028,263	10,879,160	2,333,833	4,272,664	4,272,664	5,993,550
2017/18	1,841,639	2,930,409	8,563,651	11,494,060	2,948,732	4,272,664	4,272,664	6,114,303
2018/19	1,962,627	2,997,850	9,000,307	11,998,157	3,452,829	4,272,664	4,272,664	6,235,291
2019/20	2,061,252	3,049,806	9,013,164	12,062,970	3,517,643	4,272,664	4,272,664	6,333,916
CAGR	6.1%	3.0%	3.7%	3.5%	16.9%	0.0%	0.0%	1.8%

Cap Exempt = 2014/15 Cap Exempt + Total C&I growth (Total C&I less 2014/15 Total C&I)
Cap Assigned = 50% * (Total C&I less Cap Exempt); Non-Cap Assigned = 50% * (Total C&I less Cap Exempt)
Long-Term Planning Load = Residential + Cap Assigned

Table A2-12: Normal Year Long-Term Planning Load (Dth) - New Hampshire Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Res + Cap Ass
Split Year	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Long-Term Planning Load
2014/15	1,762,722	1,870,584	3,221,162	5,091,746	1,713,309	3,378,437	0	5,141,159
2015/16	1,783,035	1,844,991	3,284,552	5,129,543	1,751,107	3,378,437	0	5,161,472
2016/17	1,813,634	1,853,319	3,395,096	5,248,416	1,869,979	3,378,437	0	5,192,071
2017/18	1,848,597	1,874,511	3,514,578	5,389,088	2,010,651	3,378,437	0	5,227,034
2018/19	1,884,065	1,887,593	3,609,464	5,497,057	2,118,620	3,378,437	0	5,262,502
2019/20	1,913,083	1,869,601	3,631,113	5,500,715	2,122,278	3,378,437	0	5,291,520
CAGR	1.7%	0.0%	2.4%	1.6%	4.4%	0.0%	n/a	0.6%

Cap Exempt = 2014/15 Cap Exempt + Total C&I growth (Total C&I less 2014/15 Total C&I)
Cap Assigned = 100% * (Total C&I less Cap Exempt)
Long-Term Planning Load = Residential + Cap Assigned

Table A2-13: Normal Year Long-Term Planning Load (Dth)

	Maine Div.	NH Div.	Northern
Split Year	Long-Term Planning Load	Long-Term Planning Load	Long-Term Planning Load
2014/15	5,805,108	5,141,159	10,946,267
2015/16	5,885,083	5,161,472	11,046,555
2016/17	5,993,550	5,192,071	11,185,621
2017/18	6,114,303	5,227,034	11,341,337
2018/19	6,235,291	5,262,502	11,497,793
2019/20	6,333,916	5,291,520	11,625,435
CAGR	1.8%	0.6%	1.2%

Normal Year Short-Term Planning Load

Table A2-14: Normal Year Short-Term Planning Load (Dth) - Maine Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Sales + CA
Split Year	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Short-Term Planning Load
2014/15	1,532,444	2,636,068	7,522,670	10,158,738	1,613,411	2,954,630	2,954,630	7,123,142
2015/16	1,612,419	2,755,237	7,578,966	10,334,204	1,625,485	2,976,741	2,976,741	7,344,397
2016/17	1,720,886	2,850,898	8,028,263	10,879,160	1,721,847	3,153,208	3,153,208	7,724,992
2017/18	1,841,639	2,930,409	8,563,651	11,494,060	1,836,673	3,363,489	3,363,489	8,135,537
2018/19	1,962,627	2,997,850	9,000,307	11,998,157	1,930,324	3,534,991	3,534,991	8,495,468
2019/20	2,061,252	3,049,806	9,013,164	12,062,970	1,933,082	3,540,041	3,540,041	8,651,099
CAGR	6.1%	3.0%	3.7%	3.5%	3.7%	3.7%	3.7%	4.0%

Cap Exempt = 2014/15 ratio of Cap Exempt to C&I Transport times C&I Transport forecast
Cap Assigned = 50% * (C&I Transport less Cap Exempt); Non-Cap Assigned = 50% * (C&I Transport less Cap Exempt)
Short-Term Planning Load = Residential + C&I Sales + Cap Assigned

Table A2-15: Normal Year Short-Term Planning Load (Dth) - New Hampshire Division

	Customer Segment Throughput				C&I Throughput by Assignment Status			Sales + CA
Split Year	Residential Throughput	C&I Sales Throughput	C&I Transport Throughput	Total C&I Throughput	Cap Exempt Throughput	Cap Assigned Throughput	Non-Cap Assn Throughput	Short-Term Planning Load
2014/15	1,762,722	1,870,584	3,221,162	5,091,746	1,713,309	1,507,853	0	5,141,159
2015/16	1,783,035	1,844,991	3,284,552	5,129,543	1,747,026	1,537,526	0	5,165,552
2016/17	1,813,634	1,853,319	3,395,096	5,248,416	1,805,823	1,589,273	0	5,256,226
2017/18	1,848,597	1,874,511	3,514,578	5,389,088	1,869,374	1,645,203	0	5,368,311
2018/19	1,884,065	1,887,593	3,609,464	5,497,057	1,919,844	1,689,620	0	5,461,278
2019/20	1,913,083	1,869,601	3,631,113	5,500,715	1,931,359	1,699,754	0	5,482,439
CAGR	1.7%	0.0%	2.4%	1.6%	2.4%	2.4%	n/a	1.3%

Cap Exempt = 2014/15 ratio of Cap Exempt to C&I Transport times C&I Transport forecast
Cap Assigned = 100% * (C&I Transport less Cap Exempt); Non-Cap Assigned = 0
Short-Term Planning Load = Residential + C&I Sales + Cap Assigned

Table A2-16: Normal Year Short-Term Planning Load (Dth)

	Maine Div.	NH Div.	Northern
Split Year	Short-Term Planning Load	Short-Term Planning Load	Short-Term Planning Load
2014/15	7,123,142	5,141,159	12,264,301
2015/16	7,344,397	5,165,552	12,509,950
2016/17	7,724,992	5,256,226	12,981,218
2017/18	8,135,537	5,368,311	13,503,848
2018/19	8,495,468	5,461,278	13,956,746
2019/20	8,651,099	5,482,439	14,133,537
CAGR	4.0%	1.3%	2.9%

Normal Year Alternative Planning Load Calculation

Table A2-17: Normal Year Alternative Planning Load (Dth)

	Maine Division			New Hampshire Division			Northern
Split Year	Normal Year Throughput	Normal Year Dual Fuel	Alternative Planning Load	Normal Year Throughput	Normal Year Dual Fuel	Alternative Planning Load	Alternative Planning Load
2014/15	11,691,183	2,824,129	8,867,053	6,854,468	1,878,854	4,975,613	13,842,667
2015/16	11,946,623	2,872,909	9,073,714	6,912,578	1,892,802	5,019,777	14,093,491
2016/17	12,600,047	3,024,407	9,575,640	7,062,050	1,936,665	5,125,384	14,701,024
2017/18	13,335,699	3,195,349	10,140,350	7,237,686	1,988,574	5,249,112	15,389,463
2018/19	13,960,784	3,335,488	10,625,296	7,381,122	2,028,414	5,352,708	15,978,004
2019/20	14,124,222	3,353,506	10,770,716	7,413,797	2,029,764	5,384,034	16,154,750
CAGR	3.9%	3.5%	4.0%	1.6%	1.6%	1.6%	3.1%

Alternative Planning Load = System Throughput less Dual Fuel Capability

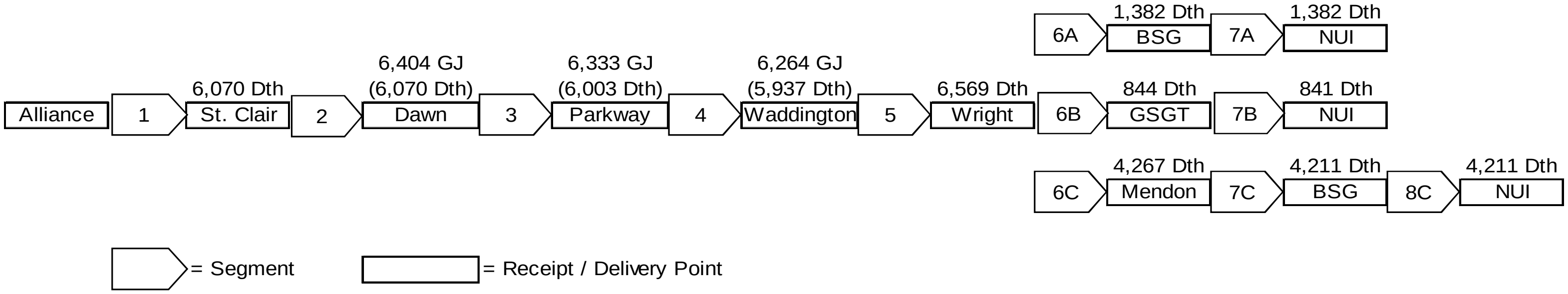
Comparison of Normal Year Planning Load Cases

Table A2-18: Normal Year Planning Load Comparisons (Dth)

		Long-Term v. Short-Term		Long-Term v. Alternative		Long-Term v. Throughput	
Split Year	Long-Term Planning Load	Short-Term Planning Load	Delta	Alternative Planning Load	Delta	Normal Year Throughput	Delta
2014/15	10,946,267	12,264,301	-1,318,034	13,842,667	-2,896,400	18,545,650	-7,599,384
2015/16	11,046,555	12,509,950	-1,463,395	14,093,491	-3,046,936	18,859,201	-7,812,646
2016/17	11,185,621	12,981,218	-1,795,597	14,701,024	-3,515,403	19,662,096	-8,476,475
2017/18	11,341,337	13,503,848	-2,162,511	15,389,463	-4,048,125	20,573,385	-9,232,047
2018/19	11,497,793	13,956,746	-2,458,953	15,978,004	-4,480,211	21,341,906	-9,844,113
2019/20	11,625,435	14,133,537	-2,508,102	16,154,750	-4,529,315	21,538,019	-9,912,584
PCT			-15%		-25%		-44%

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Chicago City Gates Supply

Chicago Path

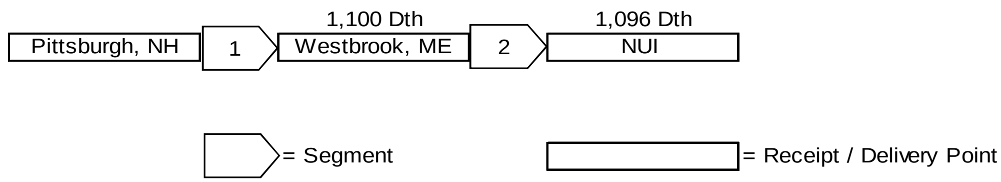


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Vector	FT-1-NUI-0122	FT-1	3/31/2016	6,070	Dth	Year-Round	Alliance Pipeline Interconnect	St. Clair	
2	Transportation	Vector	FT-1-NUI-C0122	FT-1	3/31/2016	6,404	GJ	Year-Round	St. Clair	Dawn	Union
3	Transportation	Union	M12205	M12	10/31/2017	6,333	GJ	Year-Round	Dawn	Parkway	TransCanada
4	Transportation	TransCanada	41235	FT	10/31/2017	6,264	GJ	Year-Round	Parkway	Waddington	Iroquois
5	Transportation	Iroquois	R181001	RTS-1	10/31/2017	6,569	Dth	Year-Round	Waddington	Wright	Tennessee
6A	Transportation	Tennessee	95196	FT-A	10/31/2017	1,382	Dth	Year-Round	Wright	Bay State City Gate	
7A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
6B	Transportation	Tennessee	95196	FT-A	10/31/2017	844	Dth	Year-Round	Wright	Pleasant St.	Granite
7B	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2015	841	Dth	Year-Round	Granite	Northern City Gates	
6C	Transportation	Tennessee	41099	FT-A	10/31/2017	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
7C	Transportation	Algonquin	93200F	AFT-1	10/31/2015	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
8C	Exchange	Bay State Gas	NA	NA	Renewal Clause	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,434	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: PNGTS Receipts

PNGTS Year-Round

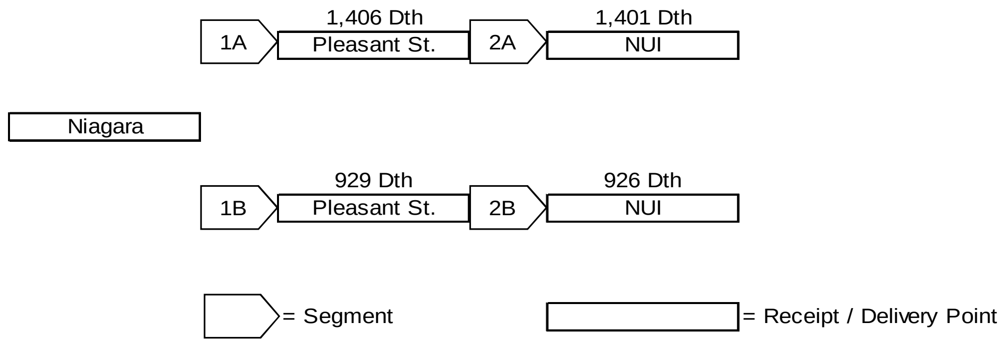


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	PNGTS	1997-003	FT	3/9/2019	1,100	Dth	Year-Round	Pittsburgh, NH	Westbrook, ME	Granite
2	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2015	1,096	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						1,096	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Niagara (Interconnection of TransCanada and Tennessee Pipelines)

Tennessee Niagara

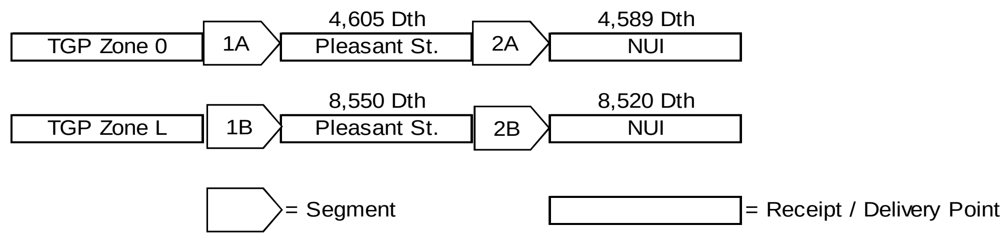


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5292	FT-A	3/31/2020	1,406	Dth	Year-Round	Niagara	Pleasant St.	Granite
2A	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2015	1,401	Dth	Year-Round	Granite	Northern City Gates	
1B	Transportation	Tennessee	39735	FT-A	3/31/2020	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2015	926	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						2,327	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Production Area

Tennessee Long-haul



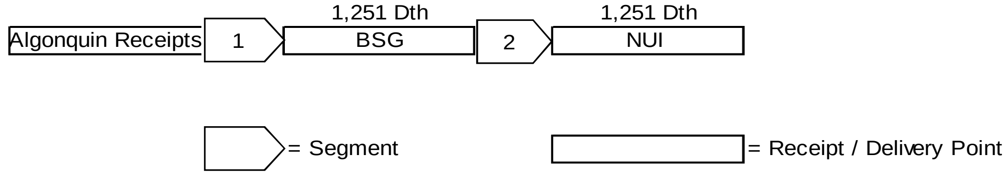
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2015	4,589	Dth	Year-Round	Granite	Northern City Gates	
1B[1]	Transportation	Tennessee	5083	FT-A	10/31/2018	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2015	8,520	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						13,109	Dth				

Note 1: Tennessee Contract No. 5083 also allows for firm delivery rights to Bay State Gas city gates. As such, Tennessee Production could also be delivered to Northern City Gates via the Bay State Exchange.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Algonquin Receipt Points

Algonquin Long-haul



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2016	1,251	Dth	Year-Round	Algonquin Receipt Points	Bay State City Gate	
2	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,251	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						1,251	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Firm Storage - Market Area

Tennessee Firm Storage

Segment	Receipt / Delivery Point	Quantity
1	TGP Zone 4	4,243 Dth
2	Pleasant St.	2,653 Dth
3	NUI	2,644 Dth

= Segment   = Receipt / Delivery Point

Capacity Path Detail

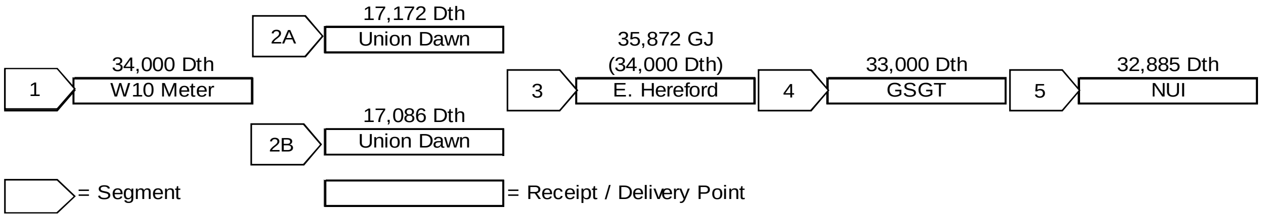
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	3/31/2020	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	3/31/2020	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2015	2,644	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,644	Dth				

Note 1: Tennessee Contract No. 5195 has a maximum storage quantity of 259,337 Dth.

Note 2: Tennessee Contract No. 5265 also allows for firm delivery rights to Bay State Gas city gates. As such, Tennessee Production could also be delivered to Northern City Gates via the Bay State Exchange.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Washington 10 Storage

Washington 10 Path



Capacity Path Detail

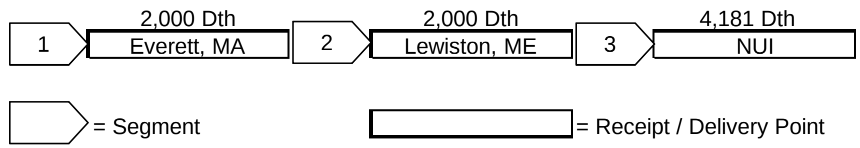
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Washington 10	01052	Firm Storage	3/31/2018	34,000	Dth	Year-Round	NA	W10 Withdrawal Meter	Vector
2A[2]	Transportation	Vector	CRL-NUI-1096	FT	10/31/2017	17,172	Dth	Year-Round	W10 Withdrawal Meter	Union Dawn	TransCanada
2B	Transportation	Vector	CRL-NUI-1097	FT	3/31/2017	17,086	Dth	Winter Only (Nov - Mar)	W10 Withdrawal Meter	Union Dawn	TransCanada
3	Transportation	TransCanada	33322	FT	3/31/2018	35,872	GJ	Year-Round	Union Dawn	East Hereford	PNGTS
4	Transportation	PNGTS	1997-004	FT	3/9/2019	33,000	Dth	Winter Only (Nov - Mar)	Pittsburgh, NH	Granite	Granite
5	Transportation	Granite	14-001-FT-NN	FT-NN	10/31/2015	32,885	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						32,885	Dth				

Note 1: Washington 10 Contract 01052 has a maximum storage quantity of 3,400,000 Dth.

Note 2: Vector Contract No. CRL-NUI-0725 allows for receipt from the Alliance Interconnect (Chicago). Gas is received on this contract at the W10 Withdrawal meter on a secondary, firm basis. This capacity is used for summer refill of the Washington 10 storage contract.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Lewiston On-System LNG

Lewiston LNG Production



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	LNG Contract	Confidential	NA	NA	10/31/2015	2,000	Dth	Year-Round	NA	Everett, MA	NA
2	LNG Trucking Contract	Confidential			10/31/2015	2,000	Dth	Year-Round	Everett, MA	Lewiston, ME	NA
3	Lewiston LNG Plant	N/A	NA	NA	N/A	4,181	Dth	Year-Round	Lewiston, ME	Northern Distribution System	
Total Path Deliverable						4,181	Dth				

Note 1: The current LNG Contract allows Northern to nominate up to 2,000 Dth per day with an annual maximum take of 75,000 Dth.

PLANNED ENHANCEMENTS, NORTHEAST NATURAL GAS PIPELINE SYSTEMS *(as of 12-3-14)*

The Northeast Gas Association (NGA) has prepared this summary based on publicly-available information. NGA will strive to keep the information as updated as possible and notes that this information may change pending project developments. May not include all projects.

PROJECT	COMPANY	DESCRIPTION	EST. IN-SERVICE	STATUS
Rockaway Lateral & Northeast Connector	Williams / Transco	The project involves a proposed 3.2-mile 26-inch lateral, consisting of approximately 2.9 miles of offshore pipeline and approximately 0.3 miles of onshore pipeline. It is designed to provide approximately 647,000 dekatherms per day of natural gas delivery capacity to National Grid's gas distribution system in Brooklyn and Queens, NY.	Northeast Connector – Dec. 2014; Rockaway Lateral, 1st qtr. 2015	Precedent agreements signed June 2009. Filed with FERC, 1-13. FERC issues final EIS, 2-14. Approved by FERC, 5-14. Under construction.
Constitution Pipeline	Cabot/Williams	Approximately 120-mile Constitution Pipeline is being designed to extend from Susquehanna County, PA, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in Schoharie County, N.Y. Proposed capacity of 650 MMCf/d. Cabot and Southwestern are announced shippers.	Late 2015	Announced spring 2012. Filed with FERC, 6-13. FERC issued final EIS, 10-14. Authorized by FERC, 12-2-14.
Wright Interconnect Project (WIP)	Iroquois Gas Transmission	WIP will enable delivery of up to 650,000 Dth/d of natural gas from the terminus of the proposed Constitution Pipeline in Schoharie County, NY into both Iroquois and the Tennessee Gas Pipeline under a 15 year capacity lease agreement with Constitution.	2015	Announced 1-13. Filed with FERC, 6-13. FERC issued final EIS, 10-14. Authorized by FERC, 12-2-14.

PLANNED ENHANCEMENTS, NORTHEAST NATURAL GAS PIPELINE SYSTEMS *(as of 12-3-14), page 2*

PROJECT	COMPANY	DESCRIPTION	EST. IN-SERVICE	STATUS
Tuscarora Lateral	National Fuel Gas Supply & Empire Pipeline	Planned capacity of 95,000 Dth/d. 17 miles of pipeline plus storage wells and lines. Market is on-system utilities (NYSEG, RG&E).	Nov. 2015	Jointly filed with FERC, March 2014.
Niagara Expansion	Tennessee Gas Pipeline	Proposed capacity of 158,000 dekatherms per day of natural gas. Seneca will serve as the foundation shipper for TGP's Niagara Expansion Project, which is designed to provide transportation from the prolific Marcellus Shale in Pennsylvania to TGP's interconnect with TransCanada Pipeline in Niagara County, N.Y.	Nov. 2015	Filed with FERC, Feb. 2014
Northern Access 2015	National Fuel Gas Supply	Capacity of 140,000 Dth/day. Capacity lease to TGP from Ellsbury to East Eden.	Nov. 2015	Filed with FERC, March 2014.
West Side 2015 Expansion	National Fuel Gas Supply	Adds 175,000 Dth/day of incremental capacity. 23 miles of 24" pipeline and additional horsepower at Mercer (TGP Sta. 219).	Nov. 2015	Filed with FERC, Feb. 2014.
Northern Access 2016	National Fuel Gas Supply & Empire Pipeline	Capacity of 350,000 Dth/day. Deliveries to Chippawa, with new interconnect at TGP 200 Line. 100+ miles of 24"/30" pipeline and Empire compressor station.	Nov. 2016	In FERC pre-filing process, July 2014.
New Market Project	Dominion Pipeline	Planned for customers in upstate NY (National Grid). Will include the addition of 2 new compressor stations along DTI's existing transmission pipeline; and increased compression at an existing station. Capacity of 112 MMcf/d.	Nov. 2016	Filed with FERC, June 2014.
AIM	Algonquin Gas Transmission / Spectra Energy	Providing 342 MMcf/d of additional capacity to move Marcellus production to Algonquin City Gates. Shippers are 6 gas utilities in New England.	2nd half 2016	Open season held, fall 2012. Filed with FERC, 2-14. FERC issues draft EIS, 8-14.

Prepared by Northeast Gas Association, December 2014. Based on publicly-available information; details may change.

PLANNED ENHANCEMENTS, NORTHEAST NATURAL GAS PIPELINE SYSTEMS *(as of 12-3-14), page 3*

PROJECT	COMPANY	DESCRIPTION	EST. IN-SERVICE	STATUS
Connecticut Expansion	Tennessee Gas Pipeline	Capacity of 72,100 Dth/d. Pipeline looping on TGP 200 and 300 lines. Market is CT natural gas utilities.	Nov. 2016	Open Season held July 2013. Filed with FERC, 7-14.
Continent to Coast (C2C) Expansion	PNGTS	C2C will access natural gas supplies from key North American natural gas basins via TransCanada Pipeline. Atlantic Canada markets can then transport on PNGTS to an interconnect with Maritimes and Northeast Pipeline at Westbrook, ME. Shippers interested in moving natural gas further south into New England can transport on PNGTS to interconnects with other NE natural gas pipelines at Dracut, Haverhill and Methuen, MA. May raise PNGTS' current capacity of 168,000 Dth/d to a total range of 300,000-350,000 Dth/d.	Nov. 2016	Open season, April 1 to June 28, 2013. Open season re-convened, Dec. 2013 – Jan. 2014.
South-to-North ("SoNo") Project	Iroquois Gas Transmission	Reverse flow on Iroquois offering physical transport to U.S./Canada border. The SoNo project would transport up to 300,000 Dth/day from Iroquois' existing interconnects with Dominion Transmission in Canajoharie, NY and Algonquin Gas Transmission in Brookfield, CT, as well as the proposed Constitution Pipeline in Wright, NY.	Nov. 2016	Open season held, Dec. 2013 – Jan. 2014.
Atlantic Bridge	Spectra Energy	Incremental expansion on Algonquin and Maritimes & Northeast, to serve northern New England and Canadian Maritimes. Capacity increase from 100 to 600,000 Dth/d.	2017	Announced, Feb. 2014. Open season held, Feb.- March, 2014.
Eastern Long Island (ELI) Project	Iroquois Gas Transmission	Proposing to build a marine lateral from its pipeline in LI Sound to a landing point at Shoreham, NY and then extent to connect with Caithness power plant and potentially National Grid.	2017	In proposal stage.

Prepared by Northeast Gas Association, December 2014. Based on publicly-available information; details may change.

PLANNED ENHANCEMENTS, NORTHEAST NATURAL GAS PIPELINE SYSTEMS *(as of 12-3-14), page 4*

PROJECT	COMPANY	DESCRIPTION	EST. IN-SERVICE	STATUS
PennEast Project	AGL Resources, NJR Pipeline Company, South Jersey Industries, UGI Energy Services, and PSE&G Power LLC	100-mile pipeline intended to bring lower cost natural gas produced in the Marcellus Shale region to homes and businesses in Pennsylvania and New Jersey. Designed to provide natural gas service to the equivalent of 4.7 million homes, up to 1 Bcf per day. PennEast is investing nearly $1 billion to build the pipeline with the costs split among the four entities. Construction of the pipeline could begin in 2017 pending regulatory approvals.	2017/2018	Announced Aug. 2014. Open season held August 2014.
Diamond East	Williams / Transco	Designed to provide up to one billion cubic feet per day of new natural gas transportation capacity from receipt points along its Leidy Line in Lycoming County, PA and Luzerne County, PA to its Market Pool at Station 210 in Mercer County, NJ where it can provide supply diversity to Transco's northeast market, including existing Pennsylvania, New Jersey and New York local distribution companies and power generators.	Mid-2018	Open season announced, Aug. 26 to Sept. 23, 2014.
Northeast Energy Direct (NED) Project	Tennessee Gas Pipeline / Kinder Morgan	This project is a combination of TGP's proposed Pennsylvania to Wright, NY and Wright, NY to Dracut, MA projects. Proposes construction of approximately 50 miles of pipeline co-located with TGP's existing system and 129 miles of greenfield pipeline, additional meter stations and compressor stations, and modifications to existing facilities in Pennsylvania, New York, Massachusetts, Connecticut, and New Hampshire. Proposed scalable capacity from 0.8 to 2.2 Bcf/d.	Nov. 2018	Open season held, Feb.-March, 2014. In July 2014, Kinder Morgan announced that 9 gas utilities in region have committed to project as initial shippers, at level of approx. 500,000 dekatherms per day (Dth/d). In FERC pre-filing process as of 9-14.
Access Northeast	Spectra Energy and Northeast Utilities	The gas pipeline expansion project will enhance the Algonquin and Maritimes pipeline systems, using existing routes to minimize effects on communities, landowners and the environment. The project will be scalable to meet growing needs by expanding access	Nov. 2018	Announced 9-14. Solicitation of interest held, fall 2014.

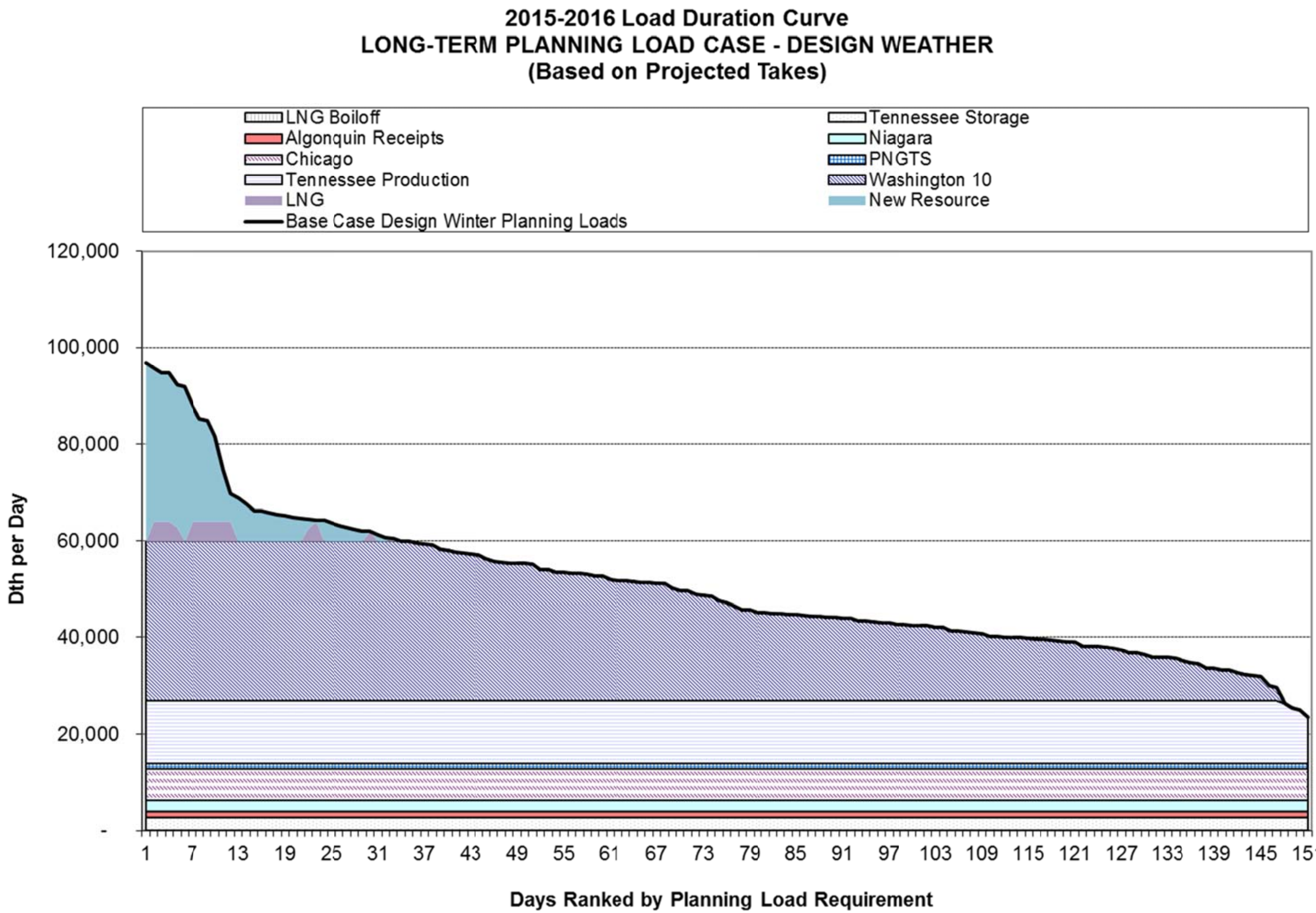
Prepared by Northeast Gas Association, December 2014. Based on publicly-available information; details may change.

PLANNED ENHANCEMENTS, NORTHEAST NATURAL GAS PIPELINE SYSTEMS *(as of 12-3-14), page 5*

		to clean, abundant and affordable natural gas, and will be capable of reliably delivering in excess of one billion cubic feet of natural gas per day to serve the region's most efficient power plants and meet increasing demand from heating customers.		

OUTLINE OF APPENDIX 5

Supplemental Materials for the Preferred Portfolio Section


2015-2016 Load Duration Curve
LONG-TERM PLANNING LOAD CASE - DESIGN WEATHER
(Based on Projected Takes)
LNG Boiloff
Algonquin Receipts
Chicago
Tennessee Production
LNG
Base Case Design Winter Planning Loads
Tennessee Storage
Niagara
PNGTS
Washington 10
New Resource
120,000
100,000
80,000
60,000
40,000
20,000
-
Dth per Day
1
7
13
19
25
31
37
43
49
55
61
67
73
79
85
91
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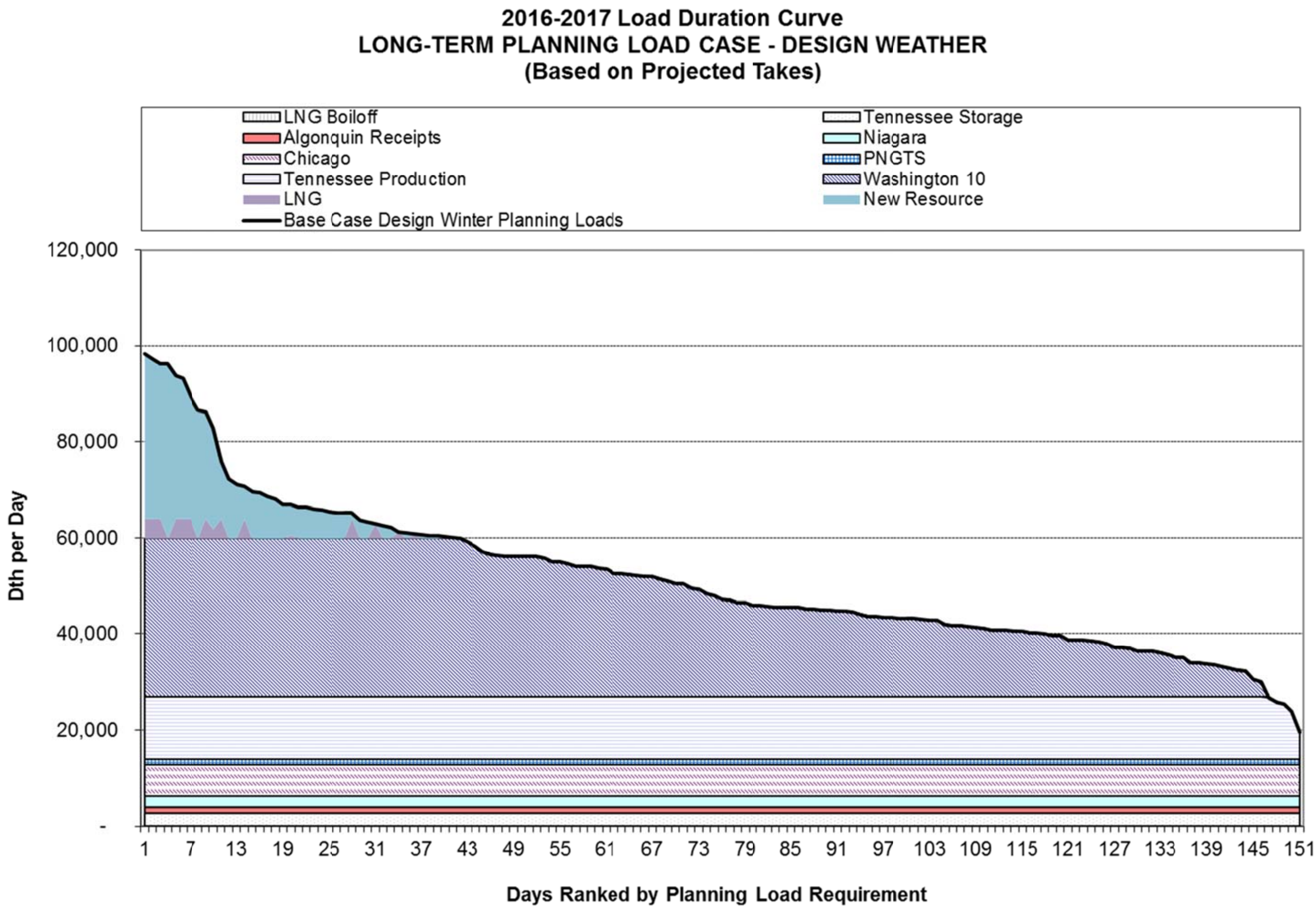
103
109
115
121
127
133
139
145
151
Days Ranked by Planning Load Requirement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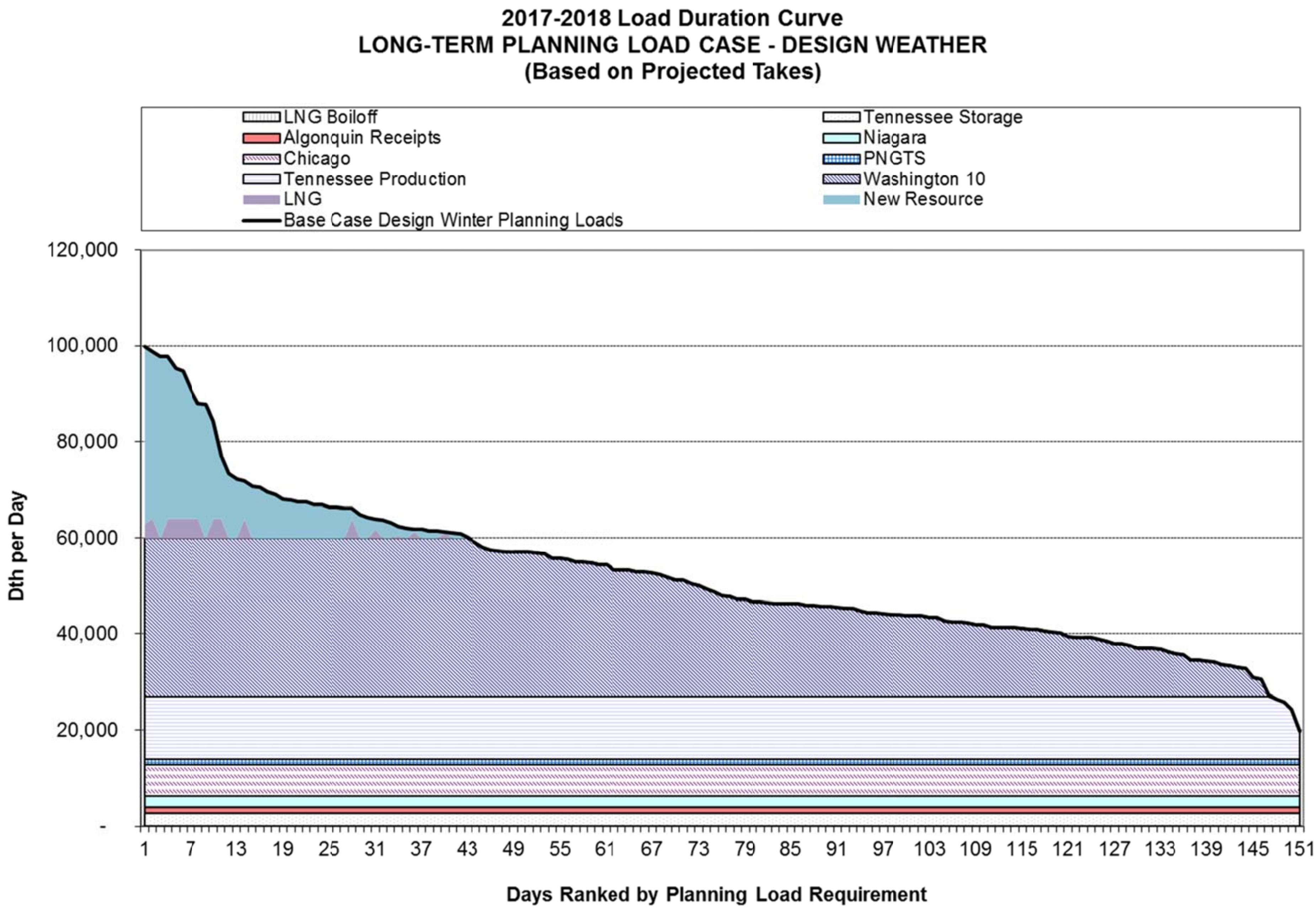
Niagara
PNGTS
Washington 10
New Resource
Dth per Day
120,000
100,000
80,000
60,000
40,000
20,000
-
1 7 13 19 25 31 37 43 49 55 61 67 73 79 85 91 97 103 109 115 121 127 133 139 145 151
Days Ranked by Planning Load Requirement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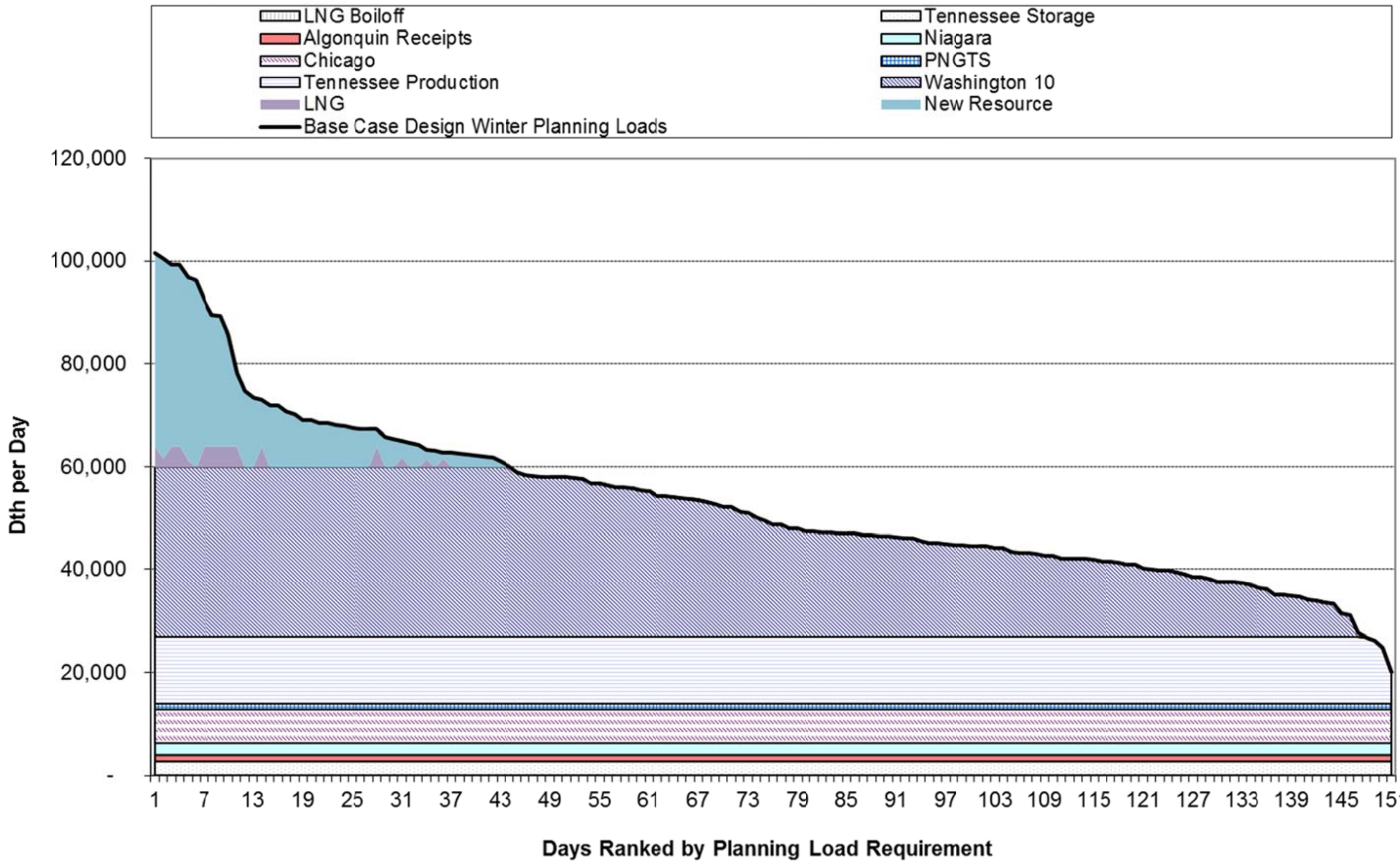
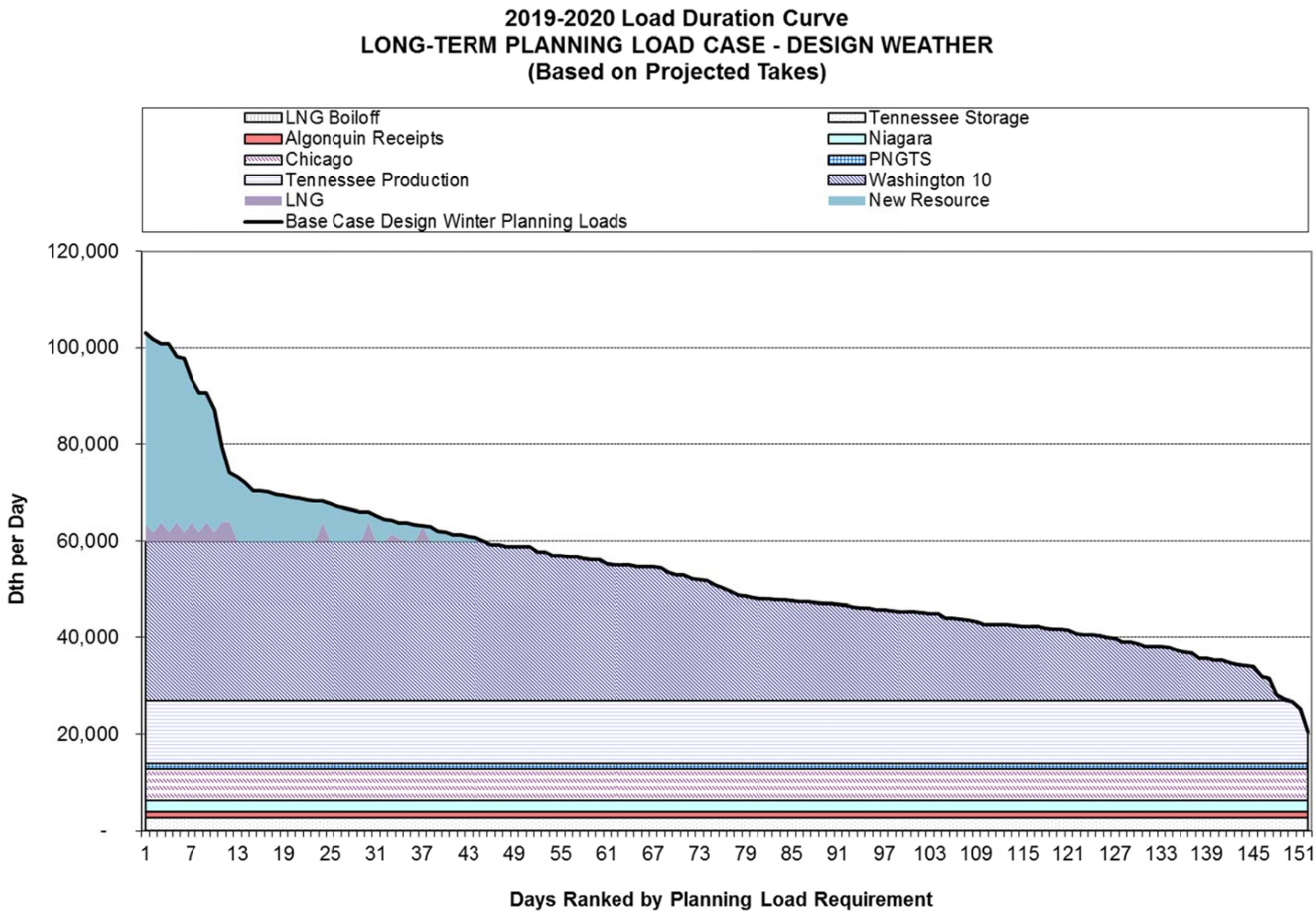
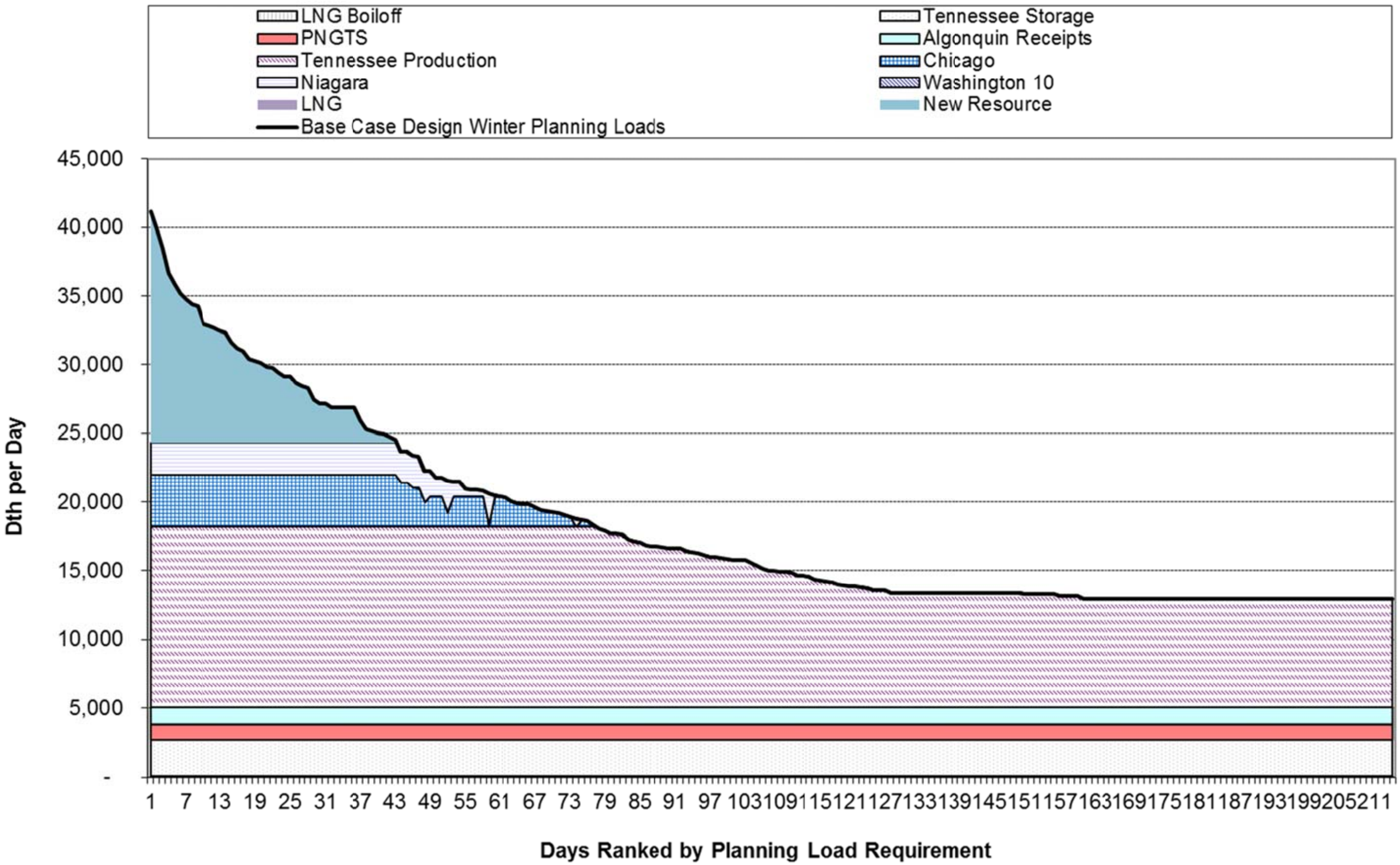
New Resource
120,000
100,000
80,000
60,000
40,000
20,000
-
Dth per Day
1 7 13 19 25 31 37 43 49 55 61 67 73 79 85 91 97 103 109 115 121 127 133 139 145 151
Days Ranked by Planning Load Requirement

2018-2019 Load Duration Curve
LONG-TERM PLANNING LOAD CASE - DESIGN WEATHER
(Based on Projected Takes)

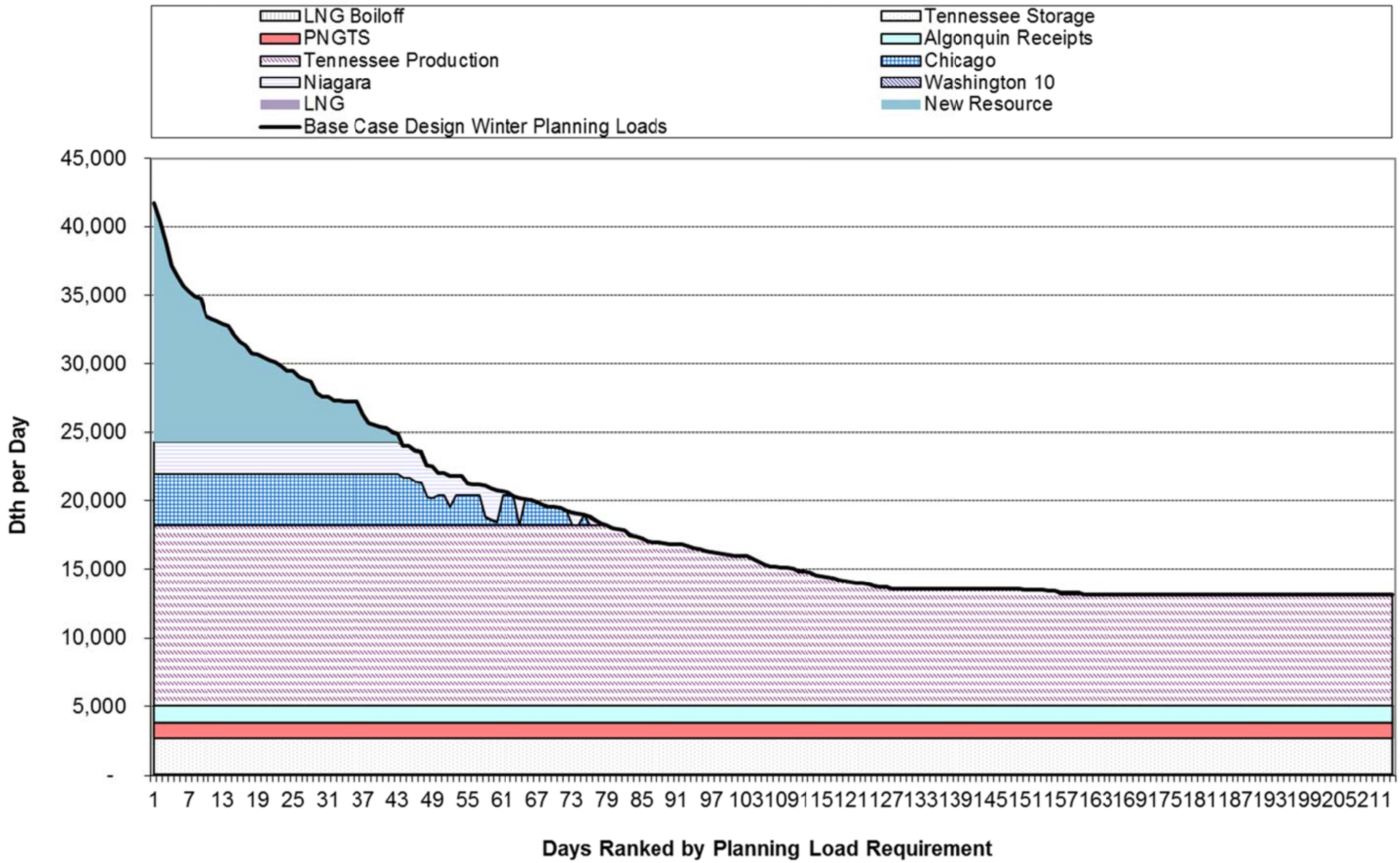


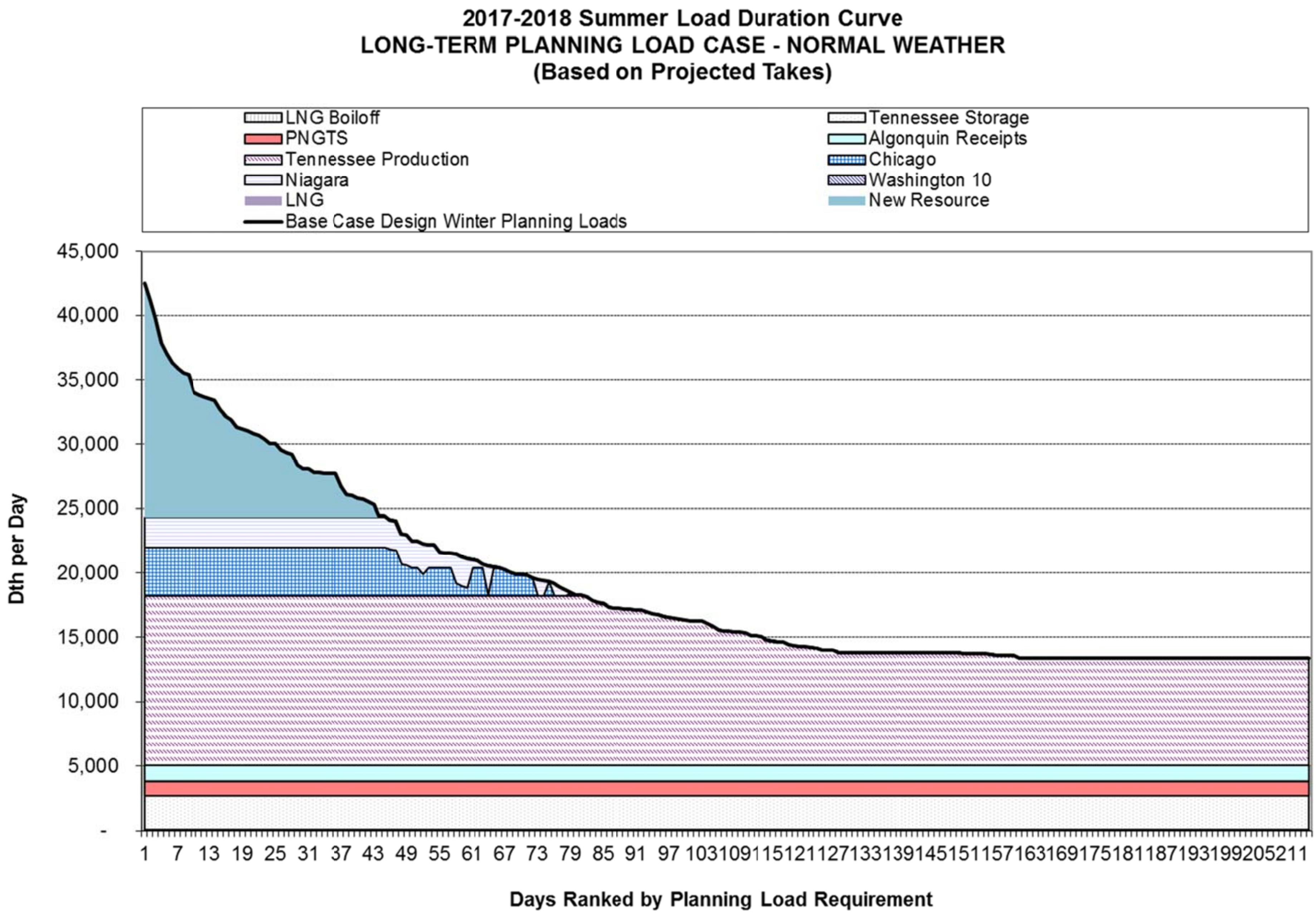

2019-2020 Load Duration Curve
LONG-TERM PLANNING LOAD CASE - DESIGN WEATHER
(Based on Projected Takes)
LNG Boiloff
Algonquin Receipts
Chicago
Tennessee Production
LNG
Base Case Design Winter Planning Loads
Tennessee Storage
Niagara
PNGTS
Washington 10
New Resource
120,000
100,000
80,000
60,000
40,000
20,000
-
Dth per Day
1
7
13
19
25
31
37
43
49
55
61
67
73
79
85
91
97
103
109
115
121
127
133
139
145
151
Days Ranked by Planning Load Requirement

2015-2016 Summer Load Duration Curve
LONG-TERM PLANNING LOAD CASE - NORMAL WEATHER
(Based on Projected Takes)

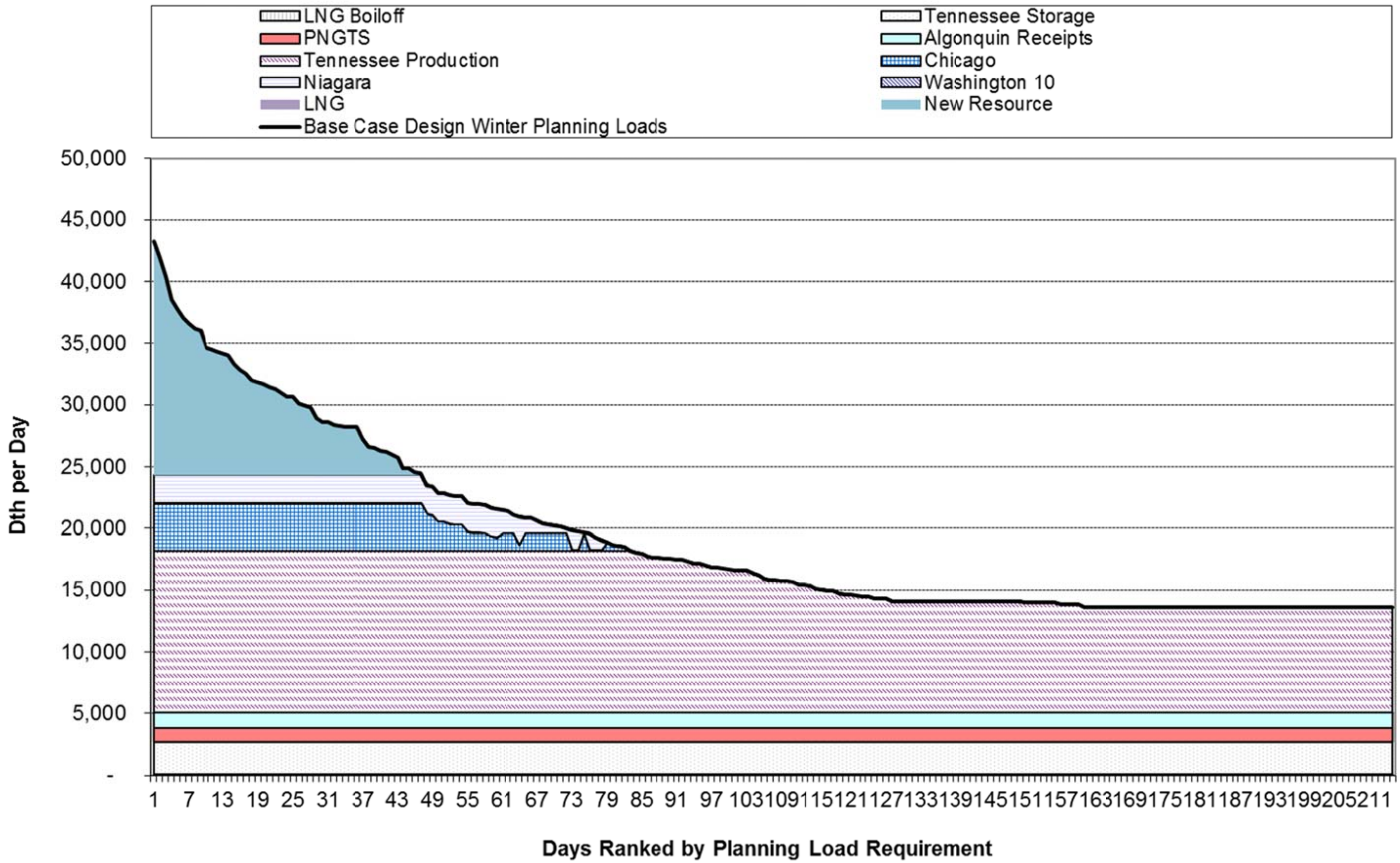


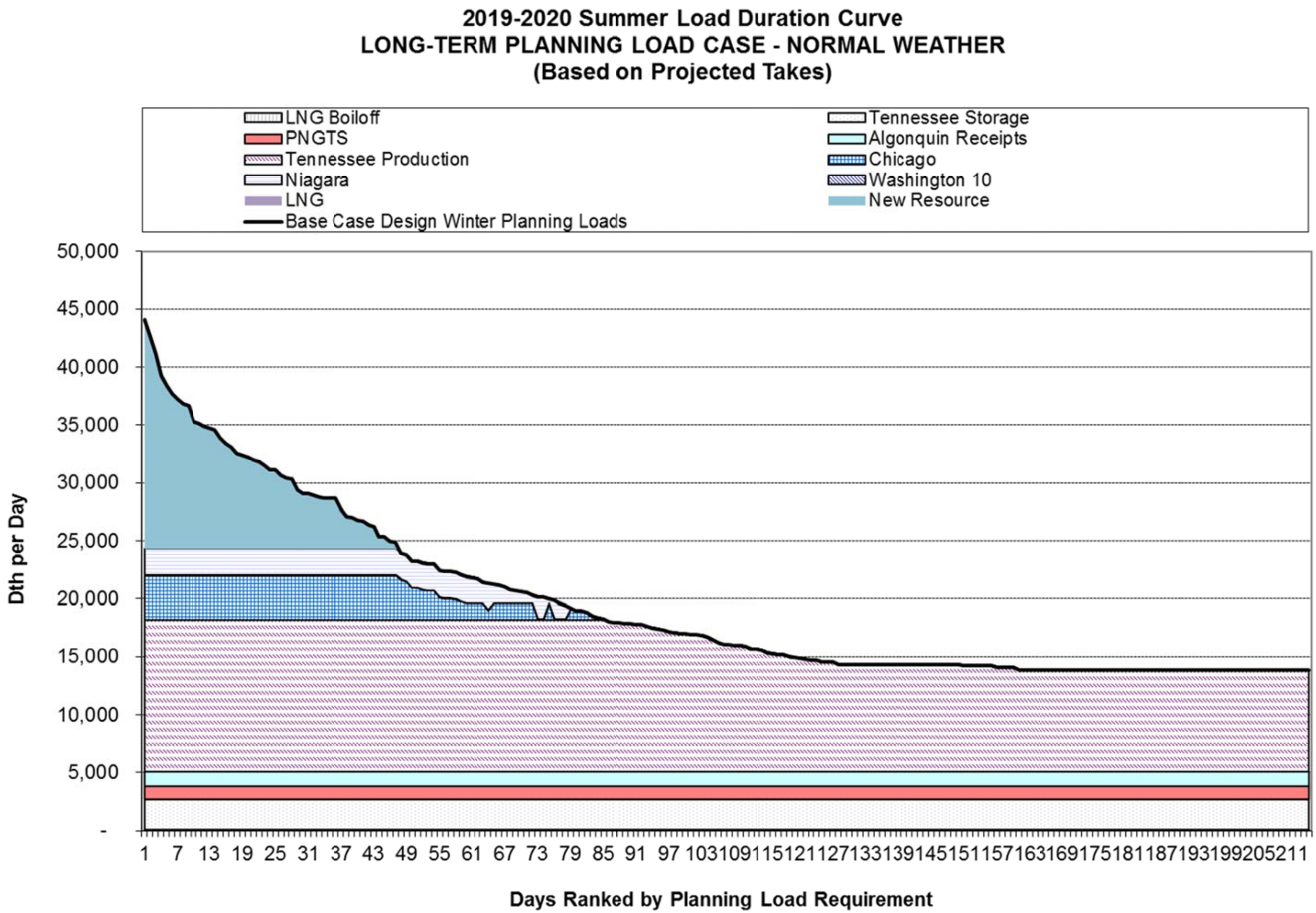
2016-2017 Summer Load Duration Curve
LONG-TERM PLANNING LOAD CASE - NORMAL WEATHER
(Based on Projected Takes)



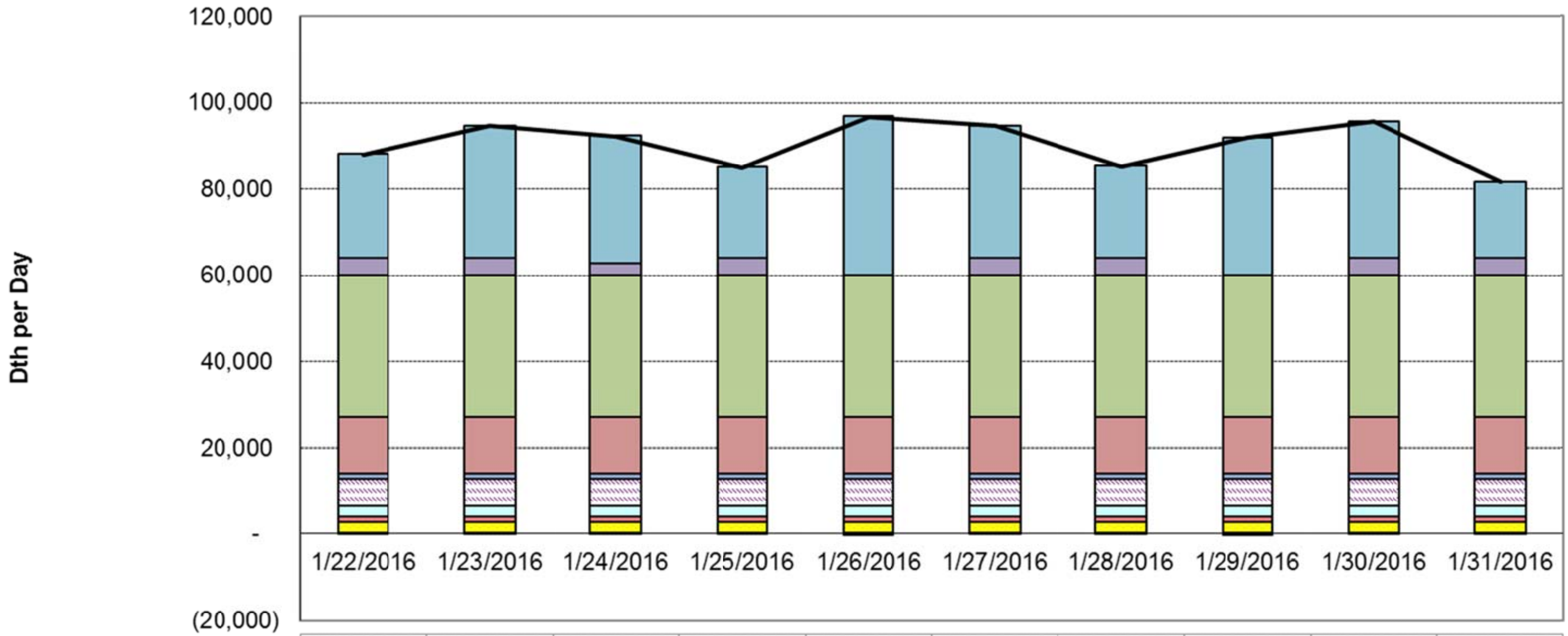

2017-2018 Summer Load Duration Curve
LONG-TERM PLANNING LOAD CASE - NORMAL WEATHER
(Based on Projected Takes)
LNG Boiloff
PNGTS
Tennessee Production
Niagara
LNG
Base Case Design Winter Planning Loads
Tennessee Storage
Algonquin Receipts
Chicago
Washington 10
New Resource
Dth per Day
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
1 7 13 19 25 31 37 43 49 55 61 67 73 79 85 91 97 103109115121127133139145151157163169175181187193199205211
Days Ranked by Planning Load Requirement

2018-2019 Summer Load Duration Curve
LONG-TERM PLANNING LOAD CASE - NORMAL WEATHER
(Based on Projected Takes)



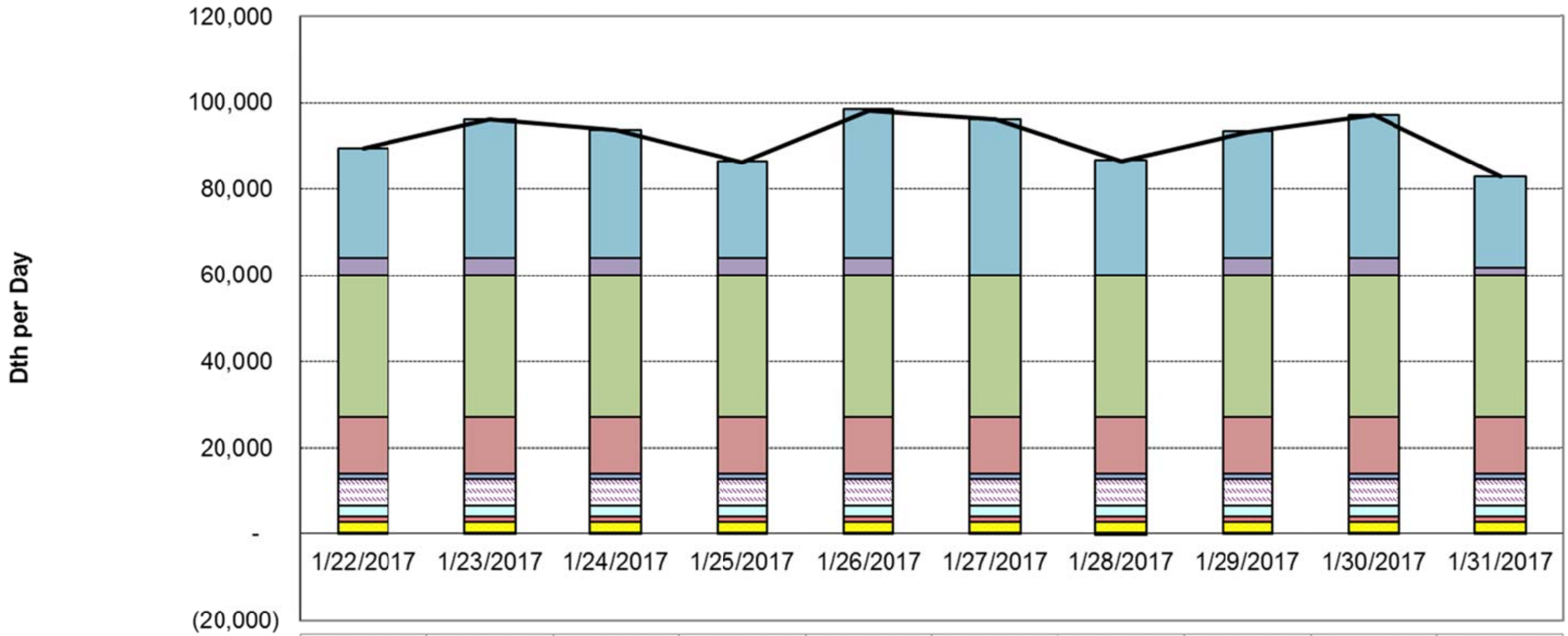

2019-2020 Summer Load Duration Curve
LONG-TERM PLANNING LOAD CASE - NORMAL WEATHER
(Based on Projected Takes)
LNG Boiloff
PNGTS
Tennessee Production
Niagara
LNG
Base Case Design Winter Planning Loads
Tennessee Storage
Algonquin Receipts
Chicago
Washington 10
New Resource
Dth per Day
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
1 7 13 19 25 31 37 43 49 55 61 67 73 79 85 91 97 103109115121127133139145151157163169175181187193199205211
Days Ranked by Planning Load Requirement

2015-2016 COLD SNAP ANALYSIS



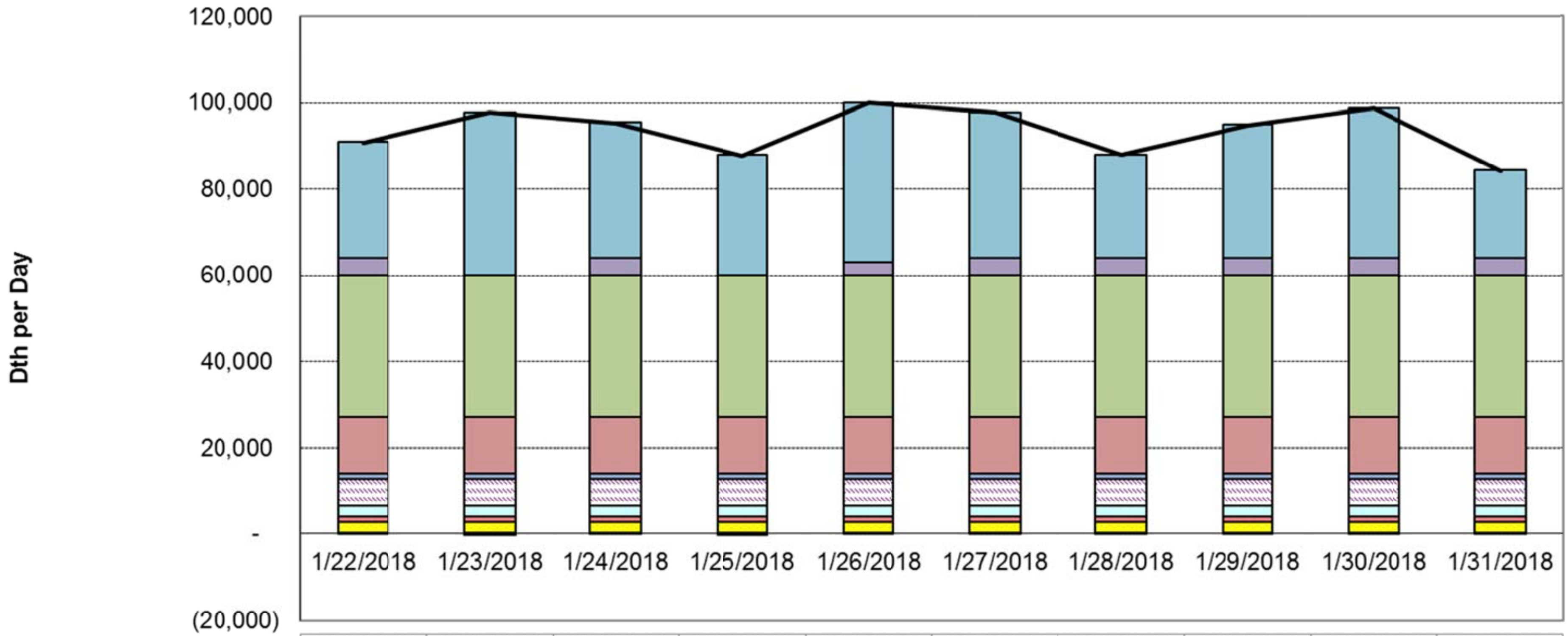
	1/22/2016	1/23/2016	1/24/2016	1/25/2016	1/26/2016	1/27/2016	1/28/2016	1/29/2016	1/30/2016	1/31/2016
New Resource	24,050	30,798	29,584	21,027	36,998	30,798	21,302	32,023	31,774	17,687
LNG	4,111	4,111	2,892	4,111	(0)	4,111	4,111	(0)	4,111	4,111
Washington 10	32,885	32,885	32,885	32,885	32,885	32,885	32,885	32,884	32,885	32,884
Tennessee Production	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
PNGTS	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096
Chicago	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448
Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
Algonquin Receipts	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	70	70	70	70	70	70	70	70	70	70
Cold Snap Loads	87,990	94,738	92,305	84,966	96,827	94,738	85,242	91,852	95,714	81,627

2016-2017 COLD SNAP ANALYSIS

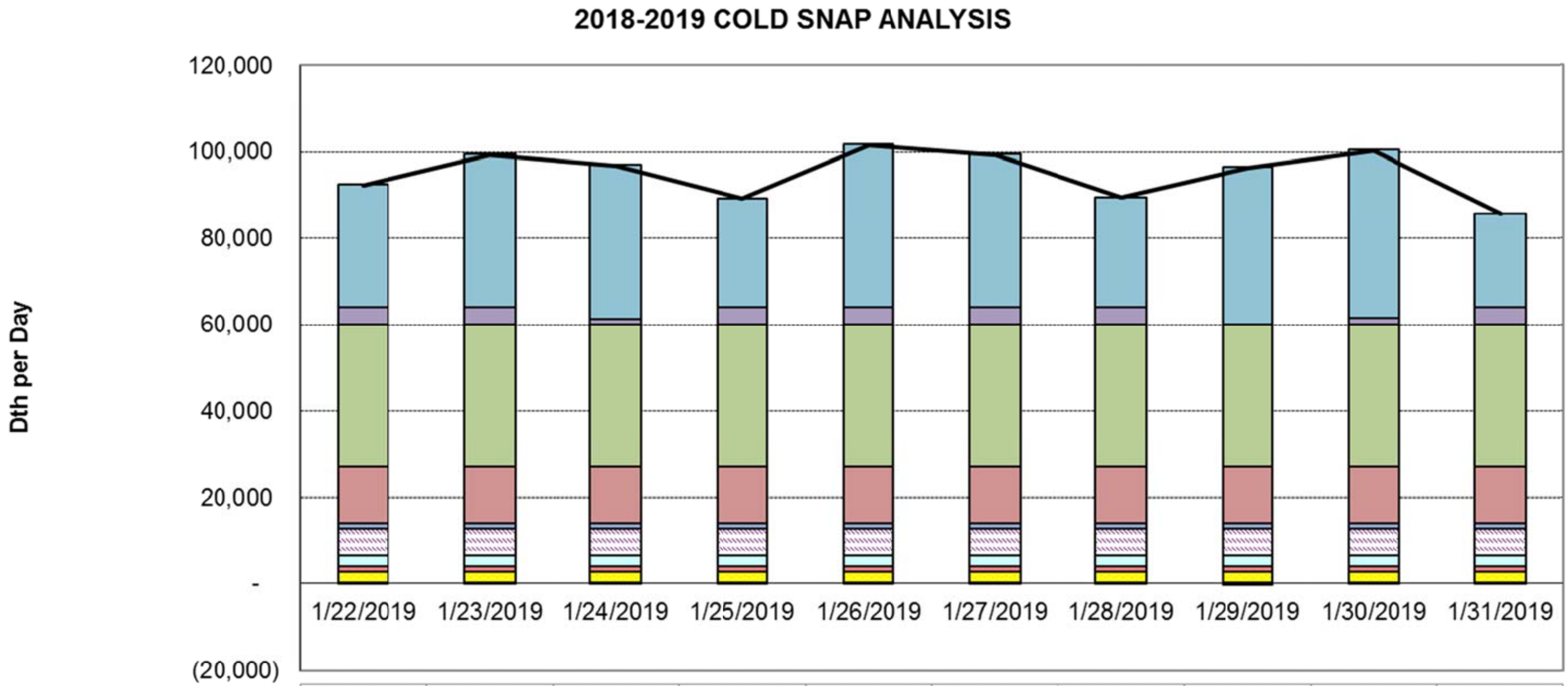


	1/22/2017	1/23/2017	1/24/2017	1/25/2017	1/26/2017	1/27/2017	1/28/2017	1/29/2017	1/30/2017	1/31/2017
New Resource	25,395	32,239	29,792	22,352	34,375	36,318	26,711	29,320	33,245	21,142
LNG	4,111	4,111	4,111	4,111	4,111	32	(0)	4,111	4,111	1,930
Washington 10	32,885	32,884	32,885	32,885	32,885	32,885	32,885	32,885	32,885	32,884
Tennessee Production	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
PNGTS	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096
Chicago	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448
Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
Algonquin Receipts	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	70	70	70	70	70	70	70	70	70	70
Cold Snap Loads	89,334	96,179	93,732	86,292	98,315	96,179	86,540	93,260	97,185	82,901

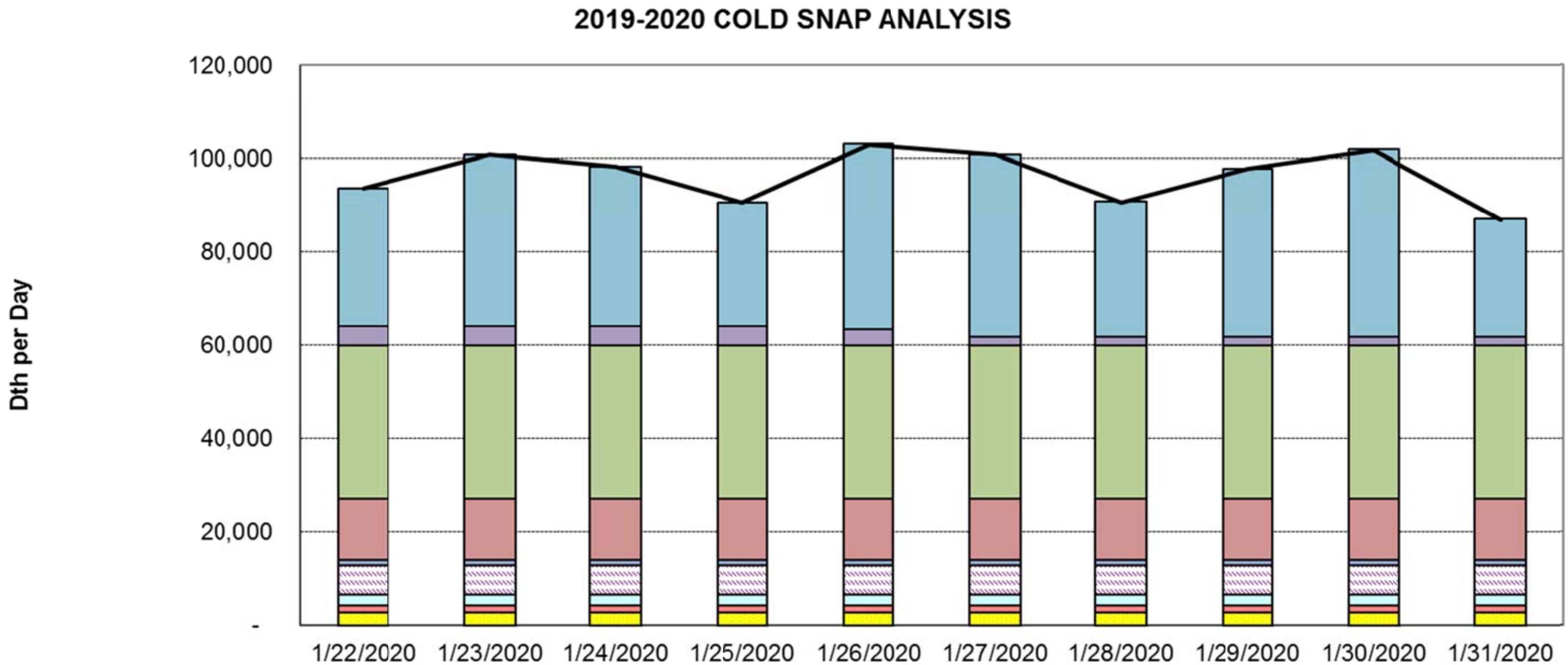
2017-2018 COLD SNAP ANALYSIS



	1/22/2018	1/23/2018	1/24/2018	1/25/2018	1/26/2018	1/27/2018	1/28/2018	1/29/2018	1/30/2018	1/31/2018
New Resource	26,839	37,894	31,320	27,884	37,012	33,783	23,996	30,829	34,820	20,329
LNG	4,111	(0)	4,111	(0)	3,067	4,111	4,111	4,111	4,111	4,111
Washington 10	32,884	32,884	32,885	32,885	32,885	32,884	32,884	32,884	32,885	32,885
Tennessee Production	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
PNGTS	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096
Chicago	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448
Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
Algonquin Receipts	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	70	70	70	70	70	70	70	70	70	70
Cold Snap Loads	90,778	97,723	95,260	87,713	99,908	97,723	87,936	94,769	98,760	84,269



	1/22/2019	1/23/2019	1/24/2019	1/25/2019	1/26/2019	1/27/2019	1/28/2019	1/29/2019	1/30/2019	1/31/2019
New Resource	28,316	35,362	35,604	25,227	37,595	35,362	25,425	36,484	38,861	21,728
LNG	4,111	4,111	1,388	4,111	4,111	4,111	4,111	(0)	1,679	4,111
Washington 10	32,885	32,884	32,884	32,885	32,884	32,884	32,885	32,884	32,885	32,884
Tennessee Production	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
PNGTS	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096
Chicago	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448
Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
Algonquin Receipts	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	70	70	70	70	70	70	70	70	70	70
Cold Snap Loads	92,255	99,302	96,821	89,166	101,535	99,302	89,365	96,312	100,369	85,668



	1/22/2020	1/23/2020	1/24/2020	1/25/2020	1/26/2020	1/27/2020	1/28/2020	1/29/2020	1/30/2020	1/31/2020
New Resource	29,660	36,800	34,302	26,550	39,619	38,981	28,907	35,958	40,075	25,183
LNG	4,111	4,111	4,111	4,111	3,569	1,930	1,930	1,930	1,930	1,930
Washington 10	32,884	32,884	32,885	32,885	32,885	32,885	32,884	32,884	32,885	32,885
Tennessee Production	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
PNGTS	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096
Chicago	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448	6,448
Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
Algonquin Receipts	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	70	70	70	70	70	70	70	70	70	70
Cold Snap Loads	93,600	100,740	98,242	90,490	103,016	100,740	90,666	97,717	101,834	86,942