Northern Utilities, Inc.

2019 Integrated Resource Plan

5-Year Natural Gas Portfolio Plan

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

July 19, 2019

Table of Contents

List of Tables & Figures

I. Executive Summary

The purpose of this Integrated Resource Plan ("IRP or "2019 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 (2019/20 – 2023/24) and review the planning processes used by Northern to develop a natural gas portfolio that provides reliable service to customers at a reasonable cost.

The 2019 IRP provides details regarding the development of the demand forecast, including reductions for target energy efficiency savings, 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 are reviewed and the Company's long-term resource decision making process is explained.

The IRP documents current market dynamics, including state energy policy and legislation in Maine and New Hampshire, 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 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 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. 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 30 year probability for supply planning, which is comparable 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 2 percent or the addition of nearly 5,000 customers over the forecast period.

Table I-1: Northern Projected Customer Counts

Gas Year	Residential Customers	C&I LLF Customers	C&I HLF Customers	Company Customers
2019/20	51,141	13,997	2,370	67,508
2020/21	52,171	14,109	2,393	68,673
2021/22	53,208	14,221	2,415	69,844
2022/23	54,250	14,331	2,438	71,019
2023/24	55,298	14,440	2,460	72,199
CAGR	2.0%	0.8%	0.9%	1.7%

Table I-2 presents the forecast of Northern's Design Year throughput, which is projected to increase at average annual rates of 1.5 percent, resulting in additional throughput of approximately 2 Bcf annually and 22,000 Dth on design day.

Table I-2: Design Year Throughput (Dth)

Gas Year	Company Net Demand (Th)	Company Net Demand (Dth)	Company Use	Lost and Unaccounted For	Design Year Throughput
2019/20	212,612,778	21,348,704	13,146	384,176	21,746,026
2020/21	215,702,538	21,659,703	13,146	389,809	22,062,658
2021/22	219,013,520	21,992,059	13,146	395,882	22,401,087
2022/23	222,250,156	22,317,247	13,146	401,802	22,732,195
2023/24	225,554,717	22,649,283	13,146	407,860	23,070,290
CAGR	1.5%	1.5%	0.0%	1.5%	1.5%

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. The resource requirement for customer demands not included in planning load is managed by the customer and their marketer.

Table I-3: Design Year Planning Load (Dth)

Gas Year	Design Year Throughput	Capacity Exempt Net Demand	Company Gas Allowance	Design Year Planning Load
2019/20	21,746,026	5,350,632	97,628	16,297,766
2020/21	22,062,658	5,429,989	99,086	16,533,583
2021/22	22,401,087	5,514,746	100,660	16,785,682
2022/23	22,732,195	5,598,164	102,203	17,031,828
2023/24	23,070,290	5,682,712	103,770	17,283,808
CAGR	1.5%	1.5%	1.5%	1.5%

In the IRP, Northern compares the 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 under design conditions 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.[1]

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 to identify and compare costs. 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. The Company has also, for the first time, evaluated resources under the framework set forth in RSA 378:38-39. 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

[1] 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.

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.

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 2019 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 2018, Northern provides service to approximately 33,071 customers in 23 communities in southern Maine and to approximately 33,715 customers in 22 communities in the seacoast region of New Hampshire. Northern's highest annual throughput was 19,760,331 Dth, which occurred during the split-year of November 1, 2017 to October 31, 2018. Northern's maximum daily throughput was 146,749 Dth, which occurred on January 21, 2019.

Northern hereby submits its 2019 Integrated Resource Plan ("IRP"), which covers the five-year planning period from November 1, 2019 to October 31, 2024.

A. Structure of the Filing

Northern's 2019 IRP filing is organized as follows:

- Section III, Planning Environment, is a new section discussing the legal, regulatory, policy and market landscape within which Northern operates;
- 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 2019/20 to 2023/24), including development of the Customer Segment Demand models, the modeling of incremental Energy Efficiency savings and resulting Normal Year Throughput forecast;
- Section V, Planning Load Forecast, introduces the planning standards Northern used to develop design condition forecasts, including Design Year and Design Day Throughput, explains the impact of Capacity Assignment provisions of the Delivery Service Terms and Conditions, and provides the methodology and results of the Company's Long-Term Planning Load forecasts;
- Section VI, Current Portfolio, introduces Resource Impact categories, which have been added to address the requirements of New Hampshire RSA 378:38, describes the Energy Efficiency resources being implemented in each Division and the Company's existing long-term Capacity Portfolio, including a discussion of resource impacts of each, and reviews supply procurement;
- Section VII, Resource Balance, provides Normal Year, Design Year and Design Day comparisons of the existing long-term resource portfolio relative to the Company's Long-Term Planning Load forecast to identify portfolio needs over the planning period;
- Section VIII, Incremental Resources Options, identifies reasonably available long-term 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;

Additional supporting materials are provided in appendices. Additional supporting materials are provided in appendices.

III.Planning Environment

Key Takeaways

Key takeaways in this chapter include the following:

- *Northern Utilities is a single company that serves customers in the states of Maine and New Hampshire and therefore is subject to utility regulation and oversight in both states.*
- *Energy and environmental policy trends in both states suggest a continued focus on decarbonization and reducing GHG emissions, supported by Energy Efficiency efforts, promotion of environmentally friendly heating sources and technologies as well as increasing opportunities for Renewable Natural Gas and new technologies.*
- *Northern has made significant strides in reducing the percentage of leak prone pipe on its distribution systems. Since 2010, Northern has reduced the percentage of leak prone pipe on its distribution mains from 103 miles to only 36 miles, a reduction of 65%. Northern currently has no remaining leak prone pipe in the New Hampshire Division.*
- *Energy Efficiency programs are developed and delivered differently in Maine and New Hampshire, and Northern has differing levels of influence over energy efficiency program design and savings targets as well as oversight of delivery in each Division.*
- *Changes in Retail Choice program design in the two Divisions since Northern's 2015 IRP have brought the programs in the two states into close alignment and importantly have stabilized the Company's Planning Load, enabling commitments to long-term capacity resources.*
- *Supplies into the region from Maritime Canada have ceased and been partly offset by expansions on PNGTS. Long term availability of market area supplies during peak periods is less certain, and the regional market remains seasonally constrained with continued exposure to volatile winter period basis pricing.*

A. Introduction

Section III describes Northern's Planning Environment. The Planning Environment section is new to Northern's Integrated Resource Plan, and is meant to identify and acknowledge the legal, regulatory and policy landscape within which Northern operates.

This Planning Environment section is organized as follows:

Part B, Statutory and Regulatory Requirements, reviews the legal and regulatory standards for integrated resource planning with which the company must comply in each state. Northern has structured its Integrated Resource Plan in order to meet these standards;

Part C, Clean Air Act of 1990, reviews the Clean Air Act and its applicability to gas distribution companies, greenhouse gas (GHG) emissions by fuel type and efforts Northern has made to improve the efficiency of its distribution system;

Part D, State Energy Policy, provides context regarding the energy and environmental policy objectives and trends in each state, such as ensuring reliability, cost effectiveness and greenhouse gas (GHG) reduction goals;

Part E, Energy Efficiency Administration, describes the process used to develop and administer energy efficiency programs in each state, and summarizes recent activity;

Part F, Retail Choice Program Design, reviews changes in the retail choice programs adopted in each state since the 2015 IRP, and the positive impact of those changes on the Company's ability to define its Planning Load;

Part G, Inter Divisional Cost Allocation, describes the process by which Northern allocates the costs of its supply portfolio to each state (division);

Part H, Regional Market Overview, discusses regional market conditions and recent changes in natural gas demand and supply dynamics to provide context for the Company's resource planning process.

B. Statutory and Regulatory Requirements

To provide context for the Integrated Resource Plan, this section reviews the respective statutory and regulatory requirements relative to resource planning in each jurisdiction.[2]

1. Maine Regulatory Requirements

There are no statutory requirements to file an Integrated Resource Plan in Maine. Northern's obligation to file an Integrated Resource Plan with the Maine Commission stems from the Stipulation and Settlement in Docket Nos. 2005-00087 and 2005-00273 (2005 Stipulation), which was approved by the Maine and New Hampshire Commissions. The Stipulation states:

The purpose of the IRP will be to keep the Maine Commission and New Hampshire Commission informed of Northern's forward-looking system planning processes and

[2] Northern notes that the 2015 IRP was submitted in compliance with the 2011 IRP Settlement, approved by the Maine Public Utilities Commission in Docket No. 2011-526 and approved by the New Hampshire Public Utilities Commission in Docket No. DG 11-290. The 2011 Settlement applied only to Northern's next IRP (the 2015 IRP). Nonetheless, Northern believes the 2019 IRP complies with all requirements of the 2011 Settlement except for the requirement to develop separate Sales Service and Transportation Service forecasts, which was not done for the 2019 IRP since there are no implications to Planning Load related to a customer's service choice during the planning period.

> *plans. The Maine Commission may provide a hearing process to review the IRP and may provide such advice or consent as the Maine Commission deems proper.*[3]

Consistent with the approach that the IRP is intended to keep the respective Commissions informed of Northern's planning processes and activities, during the proceeding in which Northern's 2015 IRP was reviewed in Maine, the Commission clarified its practice of reviewing but not approving a utility's planning practices.

> *The Commission's past dispositions of the IRP proceeding reflect its policy preference not to pre-approve matters that are within a utility's responsibility to manage prudently. In keeping with this view, and with the absence of a statutory mandate to do more, we will review the information that is presented in this proceeding and explore issues that arise regarding the Company's analysis, decision-making process and resource needs and decisions. We do not anticipate approving a planning process, decisional standards, or any of Northern's resource decisions in this case.*[4]

However, the Maine Commission has been willing to review specific long-term capacity commitments for pre-approval. Subsequent to the 2015 IRP filing, the Maine Commission reviewed and approved Northern commitments to pipeline expansion capacity on the Atlantic Bridge project, in Docket No. 2016-00229, and the Portland Xpress Project, in Docket No. 2018-00040.

Northern terminated its financial hedging program in 2018. In its Order approving the termination of Northern's financial hedging program, the Commission stated the following:

> *However, the Commission would propose that Northern include in its integrated resource planning filing an in depth discussion of its price risk management objectives and a description of actions it has taken, or will take, to reduce customers' exposure to gas price volatility from year to year, including whether or not use of financial instruments may be warranted.*[5]

In Section VI.E, Northern describes it approach to price risk management.

2. New Hampshire Statutes and Regulatory Requirements

Pursuant to New Hampshire statutes (RSA 378:37-40)[6], Northern Utilities, along with all other gas and electric utilities in New Hampshire, is required to periodically file a least cost integrated resource plan ("IRP") with the NH Public Utilities Commission to be reviewed in an adjudicative proceeding.[7] The NHPUC considers the potential environmental, economic, and health-related impacts of each proposed option included in the IRP, and if the options are determined to have equivalent

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3 Maine Docket Nos. 2005-00087 and 2005-00273, Stipulation and Settlement at 11-12.

4 Maine Docket No. 2015-00018, Procedural Order Ruling on Scope, April 23, 2015, p. 5.

5 Maine Docket No. 2018-00041, Cost of Gas Factor, May 7, 2018, p.7.

6 Please see Appendix 6 for the full text of RSA 378:37-40.

7 RSA 378:38, 39. Northern refers to its Least Cost Integrated Resource Plan as simply an Integrated Resource Plan ("IRP").

environmental, economic, and health-related impacts, energy policy shall guide the NHPUC's evaluation with energy efficiency and other demand-side management resources taking first priority, renewable energy sources taking second priority, and all other energy sources taking last priority. [8]

The IRP must demonstrate consistency with NH state energy policy:

> *...it shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost effective energy efficiency and other demand side resources; and to protect the safety and health of the citizens, the physical environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities.*[9]

In addition, the IRP must include the following:

I. A forecast of future demand for the utility's service area.
II. An assessment of demand-side energy management programs, including conservation, efficiency, and load management programs.
III. An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources.
IV. *Not Applicable* (Pursuant to Order No. 26,225 (March 13, 2019) at 7 fn 2., sub-section IV only applies to electric distribution utilities)
V. An assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers.
VI. An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state.
VII. An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1.[10]

The NH Commission's Order on Northern Utilities' last IRP (Order No. 26,027 (June 19, 2017)) confirmed that RSA 378:37-40 applies to Northern Utilities and requires compliance in this IRP.[11] Northern has considered these statutes in the development of this IRP and has addressed them throughout this report.

C. Clean Air Act of 1990

[8] RSA 378:39

[9] RSA 378:37

[10] RSA 378:38

[11] New Hampshire Docket No. DG 15-033, Order No. 26,027, June 19, 2017, p 6.

1. Overview of Clean Air Act

The Clean Air Act ("CAA") is a federal law that defines the United States Environmental Protection Agency's ("EPA") responsibilities for protecting and improving the nation's air quality and the stratospheric ozone layer. The last major change in the law, the Clean Air Act Amendments of 1990, was enacted by Congress in 1990.[12] The Act was first established in 1963 and revised in 1970, the same year that the EPA was established and given the primary role of carrying out the law. In 1990 Congress expanded and amended the CAA, giving EPA more authority to reduce air pollution. The EPA sets limits on certain air pollutants, including setting limits on how much can be in the air anywhere in the United States.[13]

The CAA requires EPA to set ambient outdoor air standards for specific pollutants. EPA has set National Ambient Air Quality Standards (NAAQS) for the six criteria air pollutants: carbon monoxide (CO), lead, nitrogen dioxide (NO2), ozone, particulate matter (PM2.5 and PM10), and sulfur dioxide (SO2).[14]

The Act is intended to improve health and the environment by reducing air pollution in the United States. The sectors listed by EPA as a part of the Act are the following: Agriculture - Crop Production and Animal Products, Automotive Sectors, Construction, Electric Power Generation, Transmission and Distribution, Oil and Gas Extraction, Transportation and Warehousing, and others.[15] While there are several industries that are directly affected by the Clean Air Act, there is no direct application of the Clean Air Act to gas utilities.

The federal government establishes minimum pipeline safety standards under the U.S. CFR, Title 49 "Transportation", Parts 190 - 199. The Office of Pipeline Safety (OPS), within the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA), has overall regulatory responsibility for hazardous liquid and gas pipelines under its jurisdiction in the United States.

Specifically, the CFRs include three parts relevant to the transport of natural gas and LNG facilities:

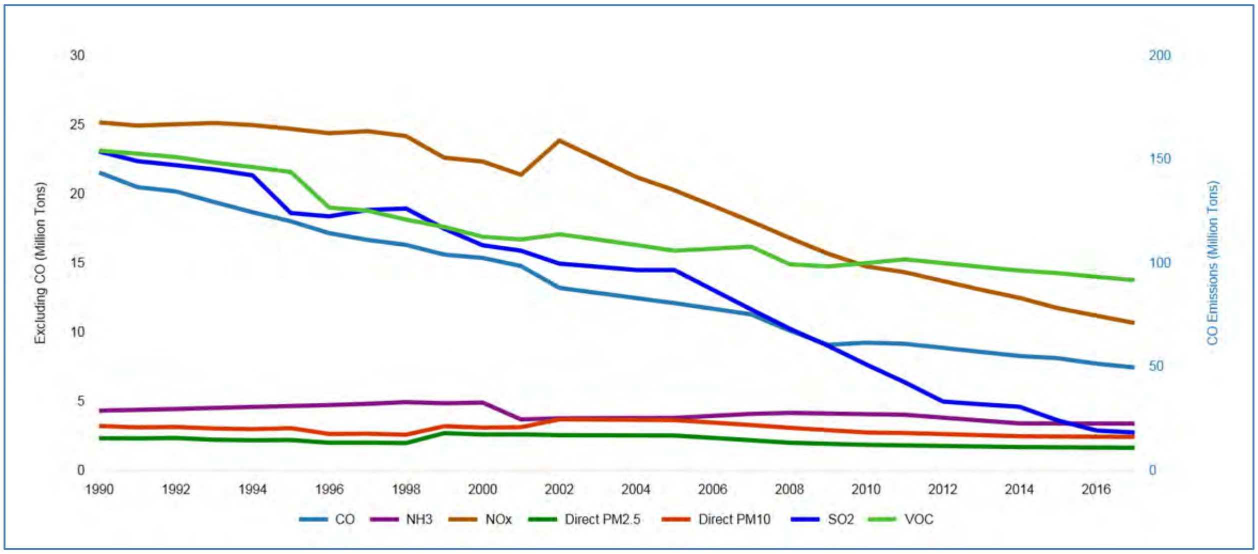
- Part 191: Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, And Safety-Related Condition Reports;
- Part 192: Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards; and
- Part 193: Liquefied Natural Gas ("LNG") Facilities: Federal Safety Standards.

[12] US EPA Clean Air Act Text, at https://www.epa.gov/clean-air-act-overview/clean-air-act-text. The Clean Air Act was incorporated into the United States Code as Title 42, Chapter 85.
[13] US EPA Regulatory Information by Topic: Air, at https://www.epa.gov/regulatory-information-topic/regulatory-information-topic-air.
[14] State of New Hampshire Air Quality–2017: Executive Edition, R-ARD-17-01-E, March 2018, Prepared by the New Hampshire Department of Environmental Services, page 3.
[15] Others listed include: Dry Cleaning, Educational Services, Forestry & Logging, Healthcare & Social Assistance, Manufacturing, Mining, Public Administration & Government, Water and Sewage Utilities Sector.

These CFRs dictate pipeline and LNG safety standards and do not address air emissions, air quality, or contain any reference to the CAA. Despite the lack of direct application of the Clean Air Act or Federal oversight of emissions through the CFRs, Northern has taken steps to minimize impacts to air quality by reducing leak prone pipe on its distribution system, as described below.

In terms of improvements in air emissions over time, in the United States from 1990 to 2014 emissions of air toxics declined by 68%. The levels of emissions of key air pollutants continue to decline from 1990 levels, as shown in Figure III-1.

Figure III-1: Declining National Air Pollutant Emissions[16]



To provide broad context on where and what types of emissions come from different sources, Figure III-2 shows pollutants emitted by source categories. The sources categories are defined as follows: "Stationary Fuel Combustion" sources include electric utilities and industrial boilers, "Industrial and Other Processes" include metal smelters, petroleum refineries, cement kilns and dry cleaners, "Highway Vehicles" is straightforward, and "Non-Road Mobile" sources include recreational and construction equipment, marine vessels, aircraft and locomotives.

The nationwide shift to natural gas for electric generation has significantly helped to reduce greenhouse gas emissions (GHG). Since the beginning of the shale gas revolution in the 2008-2009 timeframe, gas-fired electric generation has supplanted coal and gas as the primary fuel of choice. According to the EPA, total CO2 emissions from fossil fuel combustion equaled 4,966 MMTe in 2016, which is 14 percent below 2005 levels.[17]

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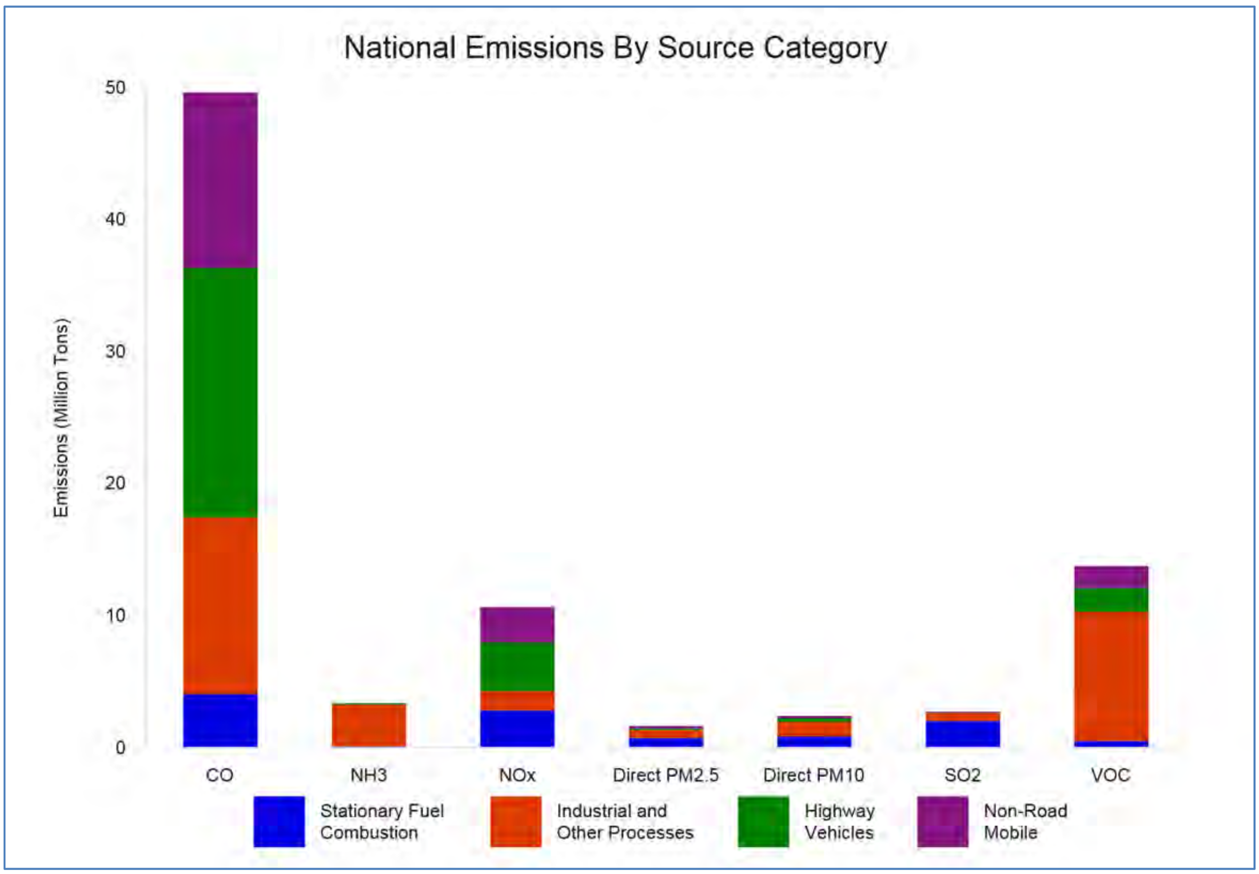
[16] Emission Trends, at https://gispub.epa.gov/air/trendsreport/2018/#highlights. Decreases are as follows: Carbon Monoxide (CO), 65%, Ammonia (NH3), 22%, Nitrogen Oxides (NOx), 58%, Direct Particulate Matter 2.5 microns (PM2.5), 29%, Direct Particulate Matter 10 microns (PM10), 25%, Sulfur Dioxide (SO2), 88%, Volatile Organic Compounds (VOC), 40%.

[17] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2016, p5.

Locally, the CAA has enabled New Hampshire to come into compliance with the National Ambient Air Quality Standards, and to maintain that compliance while improving visibility throughout the state and reducing acid, nitrogen and mercury deposition and providing a cleaner and healthier environment.[18] The EPA also lists Maine as maintaining compliance with the Standards. Both Maine and New Hampshire are listed on EPA's website as having improved visibility at national parks and scenic areas.[19]

New Hampshire Governor Christopher Sununu stated in the 2017 State of New Hampshire Air Quality report that the state "ha[s] enacted reasonable incentives for low pollution renewable power and cost-effective market-based solutions to address greenhouse gases from the energy sector."[20]

Figure III-2: National Emissions by Source Category[21]



https://www.aga.org/globalassets/research--insights/reports/ea-2018-02-updating-the-facts-of-ghg-inventory.pdf

18 State of New Hampshire Air Quality–2017: Executive Edition, R-ARD-17-01-E, March 2018, Prepared by the New Hampshire Department of Environmental Services, Page 18.

19 https://gispub.epa.gov/air/trendsreport/2018/#scenic_areas

20 State of New Hampshire Air Quality–2017: Executive Edition, R-ARD-17-01-E, March 2018, Prepared by the New Hampshire Department of Environmental Services, Page ii.

21 Emission Sources, at https://gispub.epa.gov/air/trendsreport/2018/#sources.

2. Implications of Clean Air Act for Northern

Despite no immediately direct connection between the CAA and gas distribution companies, in the spirit of the Act, Northern Utilities has focused on (i) participating in energy efficiency programs to help customers reduce their overall energy consumption; (ii) expanding its system to convert customers from oil to gas; and (iii) improving its distribution system by replacing leak prone pipe to reduce the risk of fugitive gas emissions. From a supply perspective, although Northern's gas supply portfolio is not adequate to meet its Planning Load obligations without purchasing short term supply, meaning that Northern cannot simply turnback existing supply resources, Northern is working to better understand the environmental attributes of the pipelines and storage facilities it relies upon to serve customers. Northern is also exploring non-pipeline supply options, including renewable natural gas, which could be carbon neutral or net negative.

Energy Efficiency activity is described in several sections of the IRP, including below in another part of Section III describing the environment in which Energy Efficiency programs are developed and implemented for Northern's customers, as well as in Section IV, which shows how savings targets are incorporated into the Demand Forecast, Section VI, which describes the current Energy Efficiency programs and Section VIII, which discusses possible future Energy Efficiency activity.

The share of households using natural gas, fuel oil, electricity, propane, and other fuels to heat homes varies from state to state. As shown in Table III-1, the share of homes that heat with natural gas in Maine and New Hampshire is 7.7% and 21%, respectively, both of which lag well behind the average natural gas penetration for home heating of 48% across the United States. Fuel oil is the most common home heating fuel of households in both Maine and New Hampshire.

Table III-1: Home Heating Source by State[22]

Fuel	Maine	New Hampshire	U.S. Average
Natural Gas	7.7%	21.0%	48.0%
Propane	11.4%	17.1%	4.7%
#2 Fuel Oil	61.3%	43.1%	39.0%
Electricity	6.7%	9.1%	4.7%
Other	12.8%	9.8%	3.6%

The production, delivery and consumption of natural gas produces, like other energy sources, greenhouse gases (GHGs) including Carbon dioxide (CO_2), Methane (CH4), and Nitrogen dioxide (NOx). GHGs are emitted through fuel combustion and can cause harm to humans and the environment.

22 https://www.eia.gov/state/data.php?sid=ME#ConsumptionExpenditures, https://www.eia.gov/state/data.php?sid=NH#ConsumptionExpenditures.

Representative levels of CO_2, CH4, and NOx for the combustion of major sources of heating fuel used in Maine and New Hampshire are listed in Table III-2.

Table III-2: GHG Emissions by Fuel Type[23]

Fuel	CO2 (kg/mmBtu)	CH4 (g/mmBtu)	N2O (g/mmBtu)
Natural Gas	53.06	1.0	0.1
Propane	62.87	3.0	0.6
#2 Fuel Oil	73.96	3.0	0.6
Wood	93.80	7.2	3.6

As can be seen in Table III-2, natural gas results in the lowest emissions from combustion across all GHGs when compared to other fuel types. It is also important to note that while CH4 and NOx have relatively low emissions when compared with CO2, they have much higher global warming potentials (GWP), meaning they are much more potent than CO2. Typically, greenhouse gas emissions are reported in units of carbon dioxide equivalent (CO2e). Gases are converted to CO2e by multiplying by their global warming potential (GWP), where the GWP of CO2 equals 1. The latest 100-year GWP of CH4 is 34 and the GWP of N2O is 298. See Table III-3.

Table III-3: Global Warming Potential (GWP) of GHG Emissions[24]

GHG	Lifetime (years)	100 Year GWP w/o cc fb AR5	100 Year GWP with cc fb AR5	20 Year GWP w/o cc fb AR5	20 Year GWP with cc fb, AR5
CO2	n/a	1	1	1	1
CH4	12.4	28	34	84	86
N2O	121.0	265	298	264	268

cc fb = climatecarbon feedback

In terms of converting customers from oil to gas, recent history and the IRP forecast show that Northern adds approximately new 1,150 customers annually, approximately 1,000 of which are residential. The majority of existing homes and businesses Northern acquires are customers who switch from fuel oil. On an MMBtu equivalent basis, based on the data in Table III-2, substituting natural gas for fuel oil reduces CO_2 emissions by 28 percent (53.06/73.96-1), and reduces CH4 and N2O emissions by even more.

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23 EPA, Emission Factors for Greenhouse Gas Inventories, April 2014. Available at: https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

24 Myhre, G., et.al., 2013: Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Table 8.7, p. 714.

Natural gas, or methane (CH_4), is a GHG in its natural state. Gas utilities across the nation, including Northern, have accelerated their leak-prone pipeline replacement programs in an effort to increase public safety and reduce the risk of methane fugitive emissions. According to the EPA, methane emissions from Natural Gas Systems have decreased by 14.2 percent since 1990, with decreases in distribution emissions largely due to a reduction in emissions from pipelines and distribution station leaks.[25]

The EPA assesses Natural Gas Systems in 5 separate stages, as listed in Table III-4 below. Note that emissions from natural gas distribution systems account for only 7 percent of methane emissions from natural gas systems, as shown in Table III-4.

Table III-4: CH4 Emissions from Natural Gas Systems (MMT CO2 Eq.)[26]

Stage	1990	2005	2013	2014	2015	2016	2017	2017%
Exploration	4.0	10.9	3.0	1.0	1.0	0.7	1.2	1%
Production	67.0	89.5	108.5	108.5	108.8	107.1	108.4	65%
Processing	21.3	11.6	10.8	11.1	11.1	11.4	11.7	7%
Transmission and Storage	57.2	36.1	31.0	32.4	34.2	34.5	32.4	20%
Distribution	43.5	23.3	12.3	12.2	12.0	12.0	11.9	7%
Total	193.1	171.4	165.6	165.1	167.2	165.7	165.6	100%

Both CO_2 and methane emissions have been reduced through the replacement of leak-prone pipes with state of the art materials, including high-density polyethylene (plastic). Nationwide, nearly 90 percent of the decline in fugitive emissions from distribution systems since 1990 is attributed to pipeline replacements.[27] Total leak-prone pipe (miles of distribution main) in the U.S. has decreased from 133,768 miles in 1990 to 56,771 miles in 2017.

In terms of distribution system improvements, Northern has been aggressively replacing leak-prone pipes, including bare steel, coated non-cathodically-protected steel, cast iron and wrought iron. The leak-prone pipes made from these materials are often referred to as "CIBS" (cast iron bare steel). CIBS pipe is identified as leak-prone for a variety of reasons, including its susceptibility to corrosion and graphitization. In response to multiple high-profile incidents, PHMSA issued a "Call to Action" to accelerate replacement of CIBS across the country.[28]

25 EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017, at ES-15. Available at: https://www.epa.gov/sites/production/files/2019-04/documents/us-ghg-inventory-2019-main-text.pdf

26 Ibid, at 3-82.

27 https://www.aga.org/globalassets/2019-increase-in-safety-leads-to-a-decrease-in-emissions-v.3.pdf

28 https://opsweb.phmsa.dot.gov/pipeline_replacement/action.asp

From 2010-2018,[29] Northern retired approximately 49.3 miles of leak prone (CIBS) distribution pipeline in Maine and 38 miles of leak prone distribution pipeline in New Hampshire. As of the end of 2018, Northern reports approximately 49.9 miles of leak prone pipe remaining in Maine and none in New Hampshire. As shown in Table III-5, since 2010, Northern has replaced its entire CIBS mains pipeline in the New Hampshire Division, and 50% of CIBS mains in the Maine Division. Taken together, Northern has replaced 87 miles of leak prone pipe, or 64% relative to 2010 level CIBS mains, representing a (12.0%) annual reduction. By comparison, the U.S. as a whole has only replaced approximately 34% of its 2010 level CIBS mains, representing a (5.1%) annual reduction. This comparison is shown in Table III-5.

Table III-5: CIBS Pipe Replacement: Northern vs. The U.S.[30]

	Miles of CIBS Mains		Percent of 2010 miles replaced	Annual Percentage Change
	2010	2018		
Northern ME	98.2	48.9	50%	-8.3%
Northern NH	38.0	0	100%	-
Northern Total	136.2	48.9	64%	-12.0%
U.S.	86,379	56,771	34%	-5.1%

D. State Energy Policy

State energy policy may be a function of, among other things, legislative initiatives, State Agency policy recommendations, and Public Utility Commission decisions. Over time, priorities change. Both New Hampshire and Maine periodically review state energy policy, potentially resulting in adjustments or fundamental changes in the direction and implementation of state energy policy.

1. Maine Energy Policy

In recent years, Maine has shown an increased focus on State energy policy. For example, in 2009 the Maine Legislature established the Efficiency Maine Trust ("EMT" or "Efficiency Maine") for the purposes of developing, planning, coordinating and implementing energy efficiency and alternative energy resources programs in the State. 35-A M.R.S. § 10103(1). The EMT is tasked with administering cost-effective energy and energy efficiency programs to help individuals and businesses meet their energy needs at the lowest cost by, *inter alia*, reducing the cost of energy to residents of the State, maximizing the use of cost-effective energy efficiency measures, enhancing heating improvements for households of all income levels through implementation of cost-effective efficiency programs, and using cost-effective energy and energy efficiency investments to reduce greenhouse gas emissions. 35-A

[29] Unitil acquired Northern's operations in 2009. However, PHMSA changed its reporting formats from 2009 to 2010, potentially leading to some discrepancies in the data trends. Therefore, analyses in this report begin in 2010.

[30] Source: PHMSA, Company records.

M.R.S. § 10103(2). The Maine Public Utilities Commission partially approved the EMT's most recent triennial plan for the fiscal years 2019 – 2021, but also denied certain aspects of the plan, effectively reducing the number and type of energy efficient natural gas measures that would be eligible for rebates under the EMT's programs. The Maine legislature subsequently passed H.P. 1251 - L.D. 1757, which amended 35-A M.R.S. Pt. 8, Ch. 97 to require, among other things, deference by the Commission to the EMT on certain matters including the calculation of energy savings. Maine energy efficiency is discussed further below.

Other recent energy policy legislation relevant to natural gas in Maine includes 35-A M.R.S. Pt. 8, Ch. 19, "The Maine Energy Cost Reduction Act" (ECRC). In passing the ECRC, the Maine legislature found that expansion of natural gas transmission capacity into this State and other states in the ISO-NE region could result in lower natural gas prices and, by extension, lower electricity prices for consumers in this State. 35-A M.R.S. § 1903(2). The ECRC authorizes the Maine Commission to execute an energy cost reduction contract or a physical energy storage contract, or both, subject to certain limitations. 35-A M.R.S. § 1904. To date, the Commission has not entered into any contracts under the ECRC. See 2014-00071, Order on Petitions for Clarification and Reconsideration at 5-6 (Nov. 21, 2016); 2016-00253, Order at 43 (May 17, 2017). More recently, the Maine Legislature passed L.D. 1766, "An Act To Transform Maine's Heat Pump Market To Advance Economic Security and Climate Objectives," establishing, among other things, a goal to install 100,000 new high-performance air source heat pumps in Maine by EMT fiscal year 2025 to provide heating in both residential and nonresidential spaces. The Legislature also passed LD 1679, "An Act To Establish the Maine Climate Change Council to Assist Maine to Mitigate, Prepare for and Adapt to Climate Change," which, *inter alia*, creates a "Maine Climate Change Council" and establishes greenhouse gas emissions reduction goals (less than 45% of 1990 levels by January 1, 2030 and less than 80% of 1990 levels by January 1, 2050) and energy efficiency goals (achieving electricity and natural gas program savings of at least 20% and heating fuel savings of at least 20% by 2020).

In February 2015, the Maine Governor's Energy Office issued an Update to its Comprehensive Energy Plan (the "Update").[31] The Update proposed an overarching energy policy objective of lowering costs for businesses and residential customers and reducing pollution. Update at 3. The Update noted that there had been progress made towards the 2009 Plan goal of expanding access to natural gas, and recommended continuing progress toward reducing heating costs by increasing opportunities for residents to install energy efficiency improvements and more affordable heating systems, including via access to natural gas infrastructure. Update at 8, 10, 14, 15. The Update also recommended that the State continue to pursue a regional solution to natural gas capacity constraints by working regionally, and as an individual state, to successfully expand natural gas transportation infrastructure into New England and into Maine. Id. at 3, 20. With respect to reduction of greenhouse gas emissions, the Update

[31] The State's previous Comprehensive Energy Plan was issued on January 15, 2009.

recommends that Maine continue its efforts to increase energy efficiency and replace higher emitting energy sources with renewable energy sources and low carbon emitting natural gas. Id. at 50.

2. New Hampshire Energy Policy

In April 2018, the New Hampshire Office of Strategic Initiatives (OSI) issued a first Update to the New Hampshire 10-Year State Energy Strategy.[32] The 2018 Update is a revision of the original 2014 State Energy Policy, which focused on four categories of initiatives: electric grid modernization, Energy Efficiency ("EE") strategies, fuel diversity and choice, and increased transportation options. Notably, the 2014 State Energy Policy recommended increasing customer fuel choice and reducing near-term costs by converting customers with access to natural gas. NH 2014 State Energy Strategy at 50 (explaining also that "[n]atural gas currently offers considerable cost savings as compared to other fuels, and also burns more cleanly than fuel oil, providing local and global air quality benefits"). Id.

The 2018 Update significantly revised the 2014 Strategy and focuses heavily on addressing the high cost of energy in New Hampshire and the impact of such costs on the State's residents and businesses. Goals to improve state energy policy to better meet consumer include, but are not limited to,

1. Prioritizing cost-effective energy policies;
2. Ensuring a secure, reliable, and resilient energy system;
3. Adopting all-resource energy strategies and minimize government barriers to innovation;
4. Maximizing cost-effective energy savings;
5. Achieving environmental protection that is cost-effective and enables economic growth;
6. Encouraging market-selection of cost-effective energy resources; and
7. Generating in-state economic activity without reliance on permanent subsidization of energy.

Natural gas is featured prominently in the Update, but mostly in the context of an input fuel for electric generation. The Update theme of supply diversity and elimination of economic subsidization of competing technologies favors gas expansion in the State. The Policy does discuss natural gas in in the home heating segment, however, noting that New Hampshire ranks second in the nation in oil heating per capita, with 46.4% of New Hampshire citizens using oil as their primary source of heat in 2015. New Hampshire households also rely on wood as a primary source of home heating, with over 10% of households. Correspondingly, New Hampshire has a much lower share of households using natural gas and electricity for heating (20%). Liquefied Petroleum Gases (e.g., propane) and electricity make up the remaining 15% and 8%, respectively. NH 2018 Update at 23.

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32 "The office of strategic initiatives, in consultation with the state energy advisory council established in RSA 4-E:2, with assistance from an independent consultant and with input from the public and interested parties, shall prepare a 10-year energy strategy for the state. The office shall review the strategy and consider any necessary updates in consultation with the senate energy and natural resources committee and the house science, technology and energy committee, after opportunity for public comment, at least every 3 years starting in 2017." RSA 4-E:1(I).

As is the case in Maine, New Hampshire is committed to advancing energy efficiency initiatives in the State. In 2016, the New Hampshire Public Utilities Commission approved a settlement agreement supported by, among other parties, the Commission Staff, the Office of the Consumer Advocate, and all New Hampshire electric and natural gas distribution utilities establishing a State Energy Efficiency Resource Standard ("EERS"). DE 15-137, Energy Efficiency Resource Standard, Order Approving Settlement Agreement (August 2, 2016). The EERS is a framework for the implementation of energy efficiency programs in New Hampshire, effective January 1, 2018, consisting of three-year planning periods and savings goals as well as a long-term goal of achieving all cost-effective energy efficiency. The New Hampshire electric and gas utilities are currently the administrators of the EERS programs, which are subject to Commission approval as being cost effective. The parties to the settlement agreement also agreed that in each utility's first rate case following the first three-year period of the EERS, the utility seek approval of a new rate mechanism designed to "decouple" utility sales and profits. New Hampshire energy efficiency is discussed further below.

E. Energy Efficiency Administration

Energy efficiency planning and implementation is conducted differently in the two states in which Northern operates. In Maine, energy efficiency is planned and administered centrally by Efficiency Maine Trust. In New Hampshire, Northern participates in a statewide process that identifies statewide and utility specific programs and savings targets. Northern directly designs and implements approved energy efficiency programs to its customers in New Hampshire.

1. Energy Efficiency in Maine

Ratepayer supported Energy Efficiency programs in Maine are managed and administered by Efficiency Maine Trust ("EMT" or "Efficiency Maine"), which is defined on its website as "a quasi-state agency governed by a Board of Trustees with oversight from the Maine Public Utilities Commission." Efficiency Maine collects assessments from Maine natural gas and electric local distribution companies, including Northern and manages a suite of electric and thermal efficiency programs for the state.

Efficiency Maine prepares and implements a Triennial Plan, subject to the review and oversight of the Maine PUC. The fiscal year 2020-2022 Triennial Plan was filed with the Maine Commission on November 2, 2018. The Maine Public Utilities Commission partially approved the EMT's most recent triennial plan for the fiscal years 2020 – 2022, but also denied certain aspects of the plan, effectively reducing the number and type of energy efficient natural gas measures that would be eligible for rebates under the EMT's programs. The Maine legislature subsequently passed H.P. 1251 - L.D. 1757, which amended 35-A M.R.S. Pt. 8, Ch. 97 to require, among other things, deference by the Commission to the EMT on certain matters including the calculation of energy savings.

One provision included in the legislation requires that an evaluation be undertaken no less than every three years identifying the maximum achievable cost-effective ("MACE") potential for electric and natural gas energy efficiency in Maine. It also provides that certain avoided cost and benefit elements to be included in Efficiency Maine's calculations of cost effectiveness be based on the regional Avoided Energy Supply Components ("AESC") study, which projects the value of the avoided cost of energy use realized by Energy Efficiency programs throughout the region. The AESC Study estimates the marginal value of electricity, natural gas supply, pooled transmission and distribution, oil, propane, kerosene, wood, demand reduction induced price effects, and other resources, and serves as the basis for calculating the lifetime value of energy efficiency programs in all of the New England states, including New Hampshire.

As the largest natural gas distribution company in Maine, Northern participates as an intervenor in the Maine PUC cases in which energy efficiency programs are considered. The Company is called upon to provide customer-related data and other relevant information to assist in the development and implementation of energy efficiency programs and services. As an intervenor, the Company's primary focus is on protecting the interests of its customers and ratepayers and ensuring that they receive energy efficiency program benefits commensurate with the assessment collected from Northern.

2. Energy Efficiency in New Hampshire

The energy efficiency ("EE") programs Northern offers to its New Hampshire customers are developed as part of a comprehensive, statewide approach to optimizing energy use by natural gas and electricity customers. These efforts aim to transform the marketplace for energy-using services and equipment in the built environment by working with distributors and retailers, building and installation contractors, and end use customers in the commercial, industrial, and residential sectors. As such, the energy efficiency environment in New Hampshire, particularly Northern's collaboration with other utilities in the state in planning programs and Northern's direct implementation of approved measures, is very different from the environment in Maine.

Since the adoption by the New Hampshire PUC of an Energy Efficiency Resource Standard ("EERS") in DE 15-137, Order 25,932 on August 2, 2016, the Company has pursued cost effective energy efficiency in pursuit of annual energy saving goals established through a robust stakeholder process. The New Hampshire Public Utilities Commission approved a settlement agreement allowing for the implementation of the New Hampshire electric and natural gas utilities' first three-year energy efficiency plan on January 2, 2018.[33] The Commission subsequently approved a 2018 Update Plan that continues previously approved energy efficiency program elements.[34]

F. Retail Choice Program Design

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

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33 DE 17-136, 2018-2020 New Hampshire Statewide Energy Efficiency Plan, Order No. 26,095 (Jan. 2, 2018).

34 DE 17-136, 2018-2020 New Hampshire Statewide Energy Efficiency Plan, Order No. 26,207 (Dec. 31, 2018)

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 impact Northern's Planning Load.

At the time Northern's 2015 IRP was filed, there were significant differences in the terms of the Delivery Service Tariffs in the two Divisions and certain program attributes lead to unstable Planning Load obligations, which significantly impacted the approach taken in the 2015 IRP. However, during the intervening years changes have been made to the Delivery Service Tariffs in both states that have brought the two tariffs into close alignment. Effective November 1, 2019, Capacity Assignment in the Maine Division will be based on 100 percent of a Transportation Service customer's peak day demand, which will be consistent with the approach taken in the New Hampshire Division. Since the planning horizon begins with Gas Year 2019/20, the IRP has been developed assuming 100 percent capacity assignment in the Maine Division.

1. Capacity Assignment Changes in the Maine Division

The Company's 2014 proposal, "Proposed Changes to Northern's Retail Choice Program", Maine PUC Docket No. 2014-00132 ("Retail Choice docket"), resulted in major changes to Northern's Maine Division retail choice program, as codified in Northern's Delivery Service Terms and Conditions. The changes were approved in two separate Maine PUC Orders.

The Maine PUC Order Approving Stipulation, dated October 26, 2015, addressed Phase 1 issues and resulted in (1) assignment of all capacity resources rather than select resources; (2) assignment of resources on a year round basis or otherwise in accordance with contractual terms rather than only during the winter period; (3) assignment of resources via capacity release where possible rather than only via company-management; (4) cessation of the assignment of off-system peaking supply; and (5) provided that each assigned resource shall be priced at actual demand and commodity cost by resource rather than at system average cost.

The Maine PUC Order dated July 7, 2016, addressed Phase 2 issues and resulted in (1) capacity assignment based upon 100 percent of a customer's peak day demand as of November 1, 2019, rather than 50 percent of a customer's peak day demand, which had been the practice since the inception of the program; (2) Capacity Exempt status continuing for existing exempt customers and new customers who use 25,000 ccf annually, with a requirement for daily metering, and a one-time open season for legacy customers who were capacity assigned, had never taken Sales Service and who met the usage threshold to choose to become capacity exempt; (3) adopted a Capacity Ratio as part of the determination of Total Capacity Quantity ("TCQ"), which is the amount of capacity to be assigned to each customer, and provided for an annual review of customer TCQ, with updates if the TCQ changes by more than 5% from the prior year; and (4) updated the migration fee and stay period requirements such that customers who switch from Delivery Service to Sales Service must remain on Sales Service until the subsequent April 30 and pay a commodity based re-entry charge (for capacity assigned customers) or conversion charge (for capacity exempt customer) while during the stay period.

Approximately 150 customers with a combined peak day demand of 11,400 Dth participated in the Capacity Exempt open season in the fall of 2016, including some smaller (non G-42/52) customers who were already Capacity Exempt but who needed to install a daily meter to retain Capacity Exempt status. Approximately 70 percent of customers accounting for 85 percent of peak day demand chose to become or remain Capacity Exempt, which became effective the summer of 2017. As part of its forecasting effort, Northern restated the history of these customers as though they had been Capacity Exempt throughout the historical period used to develop the forecast, beginning in November 2014.

The changes to the Company's Delivery Service Terms and Conditions adopted in the Maine Division ultimately adopted several important customer protections and stabilized Northern's Planning Load, allowing the Company to explore capacity resource additions to the its gas supply portfolio.

2. Capacity Assignment Changes in the New Hampshire Division

In 2017, in Docket No. DG 17-401, the New Hampshire Division adopted many of the innovative Retail Choice changes that had been adopted in the Maine Division. These included adopting the Capacity Ratio and Annual TCQ Reviews, effective November 2018; clarifying that Canadian capacity may be assigned via capacity release and that retail suppliers will procure their own off-system supplies; and adopting the new migration fee structure and stay period requirements such that customers who switch from Delivery Service to Sales Service must remain on Sales Service until the subsequent April 30 and pay a commodity based re-entry charge.

These provisions apply to customers in both Divisions and are discussed further under the Capacity Assignment portion of the Planning Load Section.

G. Inter Divisional Cost Allocation

Since Northern is a single company managing a single portfolio to serve customers in two states, Maine and New Hampshire, subject to the oversight and approval of the Public Utilities Commissions in each state, it is critical that gas supply cost allocation between the states be well understood and accepted in both states.

To assign demand costs equitably between the Maine and New Hampshire Divisions, Northern utilizes the Modified Proportional Responsibility ("MPR") allocation method. The MPR methodology was developed in response to the emergence of retail choice programs in both states and was approved by Maine PUC pursuant to Settlements in Docket Nos. 2005-00098 and 2005-00273, and by the New Hampshire PUC in Docket No. DG 05-080. Approval of the methodology was reiterated in Maine Docket

No. 2017-00117 in which, subsequent to the numerous changes made to the Delivery Service Terms and Conditions in Docket No. 2014-00132, the Maine PUC determined that the MPR methodology was still the best method for inter-divisional cost allocation notwithstanding the changes to Northern's retail choice program in Maine. During the pendency of the Maine PUC dockets on retail choice and cost allocation, a New Hampshire PUC investigation into whether the methodology used by Northern to allocate gas supply costs between New Hampshire and Maine was just and reasonable, Docket No. IR 15-009. In 2018, following the retail choice changes and affirmation of the MPR allocation method in the Maine Division, the investigation was closed.

The approval and support of the MPR methodology from the Maine and New Hampshire Commissions provide Northern with assurance and stability in its long term planning process and allows the Company to focus on obtaining low cost and reliable resources without the distraction of cost allocation issues.

The MPR allocation methodology is designed to equitably assign costs to both sales customers and capacity assigned (non-exempt) transportation customers in each division based on those customers' demand requirements. The MPR allocation methodology assigns costs to each division based on prior year sales and dispatch of resources that are adjusted for design weather conditions. Using a linear optimization model, Northern determines the optimal dispatch of resources (pipeline, storage and peaking) in the design weather conditions. Northern's supply resource costs (pipeline, storage and peaking) are then allocated to each month based on the percentage of the monthly utilization of that resource. This assigns resource costs to each month based on usage. The monthly costs are then allocated to each division based on the percentage of total demand that is comprised from each division. Once allocated to each division, the monthly costs are then summed with the percentage comprised from each division equaling that division's PR allocator.

Commodity costs are allocated between the Maine and New Hampshire divisions based on each division's percentage of monthly firm sendout. This methodology has been in place for many years.

H. 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 1, Decline in Natural Gas Supplies into Maritimes, discusses the natural gas supply and demand issues in Atlantic Canada that have impacted the New England markets;

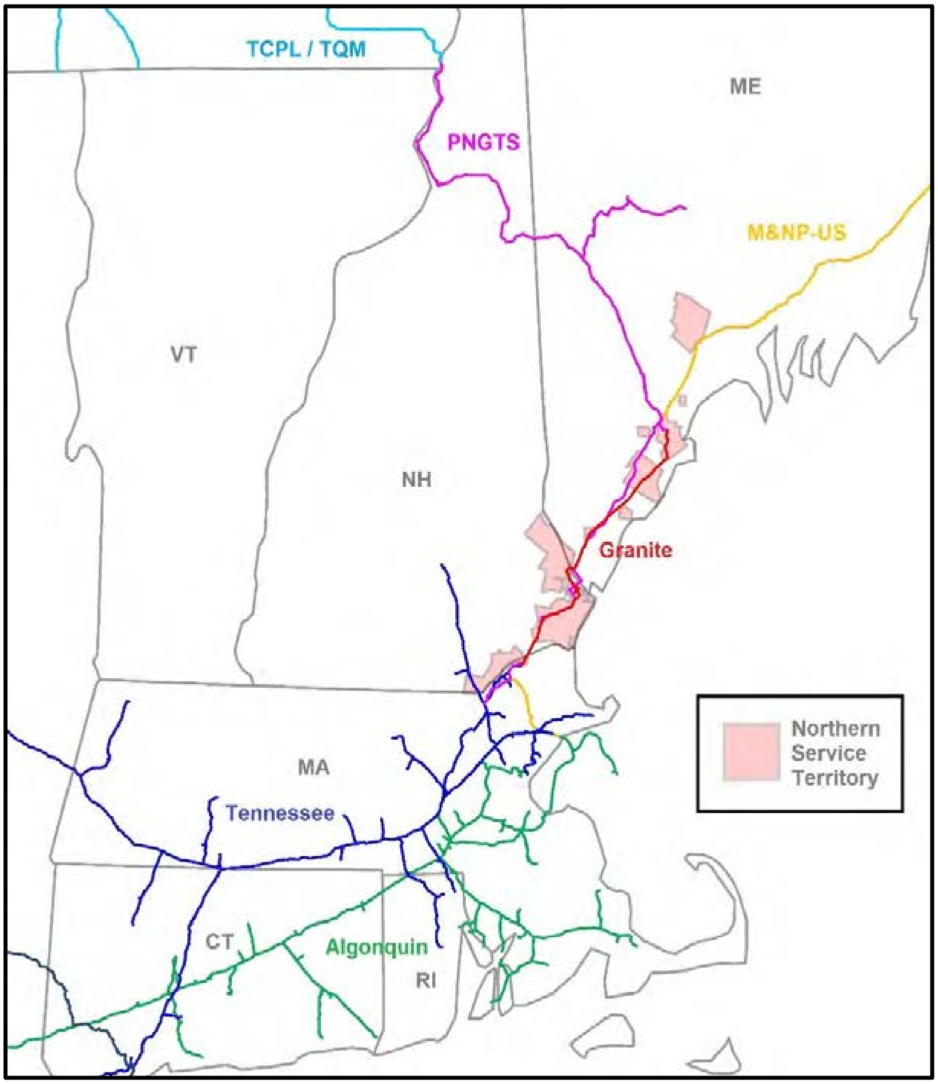
Part 2, Significant Uncertainty Related to Supplies from Distrigas, reviews the LNG activity in the New England region, and discusses the impact of alternative LNG markets on New England LNG supply;

Part 3, Limited Pipeline Expansion Projects to Serve New England, underscores the limited options available to add natural gas pipeline capacity to the portfolio;

Part 4, Natural Gas Price Implications, reviews the regional natural gas prices and the impact of energy market conditions on New England natural gas prices and basis values.

As discussed in the Regional Market Overview of the Company's 2015 IRP, the Company continues to face significant uncertainty in the regional natural gas market. Specifically, the New England natural gas environment can be characterized as one with high market area prices with significant volatility; and the expected natural gas supply dynamics in the region will likely exacerbate the market uncertainty. To provide the appropriate context for the Regional Market Overview with respect to natural gas infrastructure, Figure III-3 below illustrates Northern's service territory in Maine and New Hampshire relative to the existing natural gas pipelines and proposed pipeline capacity projects in the New England region.

Figure III-3: Northern Service Territory and Natural Gas Pipeline Infrastructure



As shown in Figure III-3 above, the Northern service territory is served by three major interstate pipelines in New England; specifically, Maritimes, PNGTS, and Tennessee, each of which deliver to Northern directly or via Granite and provide the Company with access to various natural gas supply sources.

As further detailed in the sections that follow, the natural gas supply sources delivered to Maritimes from off-shore Nova Scotia (i.e., Sable Island and Deep Panuke) have ceased production, leaving vaporized LNG from Canaport as the only remaining source of gas supply into Maritimes.[35] In addition, there is uncertainty regarding future service offerings and associated prices from the Distrigas facility in Everett, MA, which is another major source of imported LNG into the New England region via

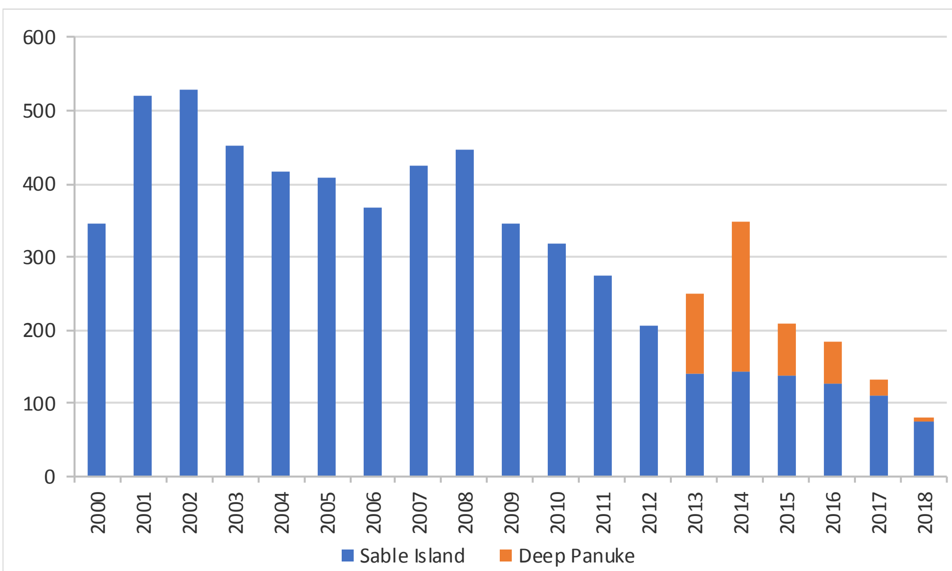
[35] This does not include a limited amount of natural gas production from Corridor Resources in New Brunswick. Source: Corridor Resources press release, "Corridor Announces 2018 Year End Results and Reserves", March 27, 2019.

interconnections with Tennessee and Algonquin. Finally, the only new pipeline capacity project announced to provide incremental gas supply to the region since the Portland XPress Project is the Westbrook XPress Project; and, at this time, there continues to be no new projects for pipeline capacity from the south on Tennessee or Algonquin. As discussed in detail below, these natural gas market challenges continue to place upward pressure on New England natural gas price indices thus increasing exposure to entities that contract for gas supplies priced at these market area prices.

1. Decline in Natural Gas Supplies into Maritimes

Prior to 2019, the major sources of natural gas supply delivered to Maritimes were Sable Island, Deep Panuke, and Canaport. Since the Company's request for approval of the Portland XPress precedent agreement, natural gas production from Sable Island and Deep Panuke in Atlantic Canada has ceased. While natural gas production from off-shore Nova Scotia was expected to end in the 2019 to 2020 time frame, Sable Island and Deep Panuke permanently shut down in 2018, further limiting the availability of natural gas supply sources to serve demand in the New England and Atlantic Canada regions. Figure III-4 below illustrates the historic production from Sable Island and Deep Panuke.

Figure III-4: Sable Island and Deep Panuke Average Daily Production (MMcf/day)[36]

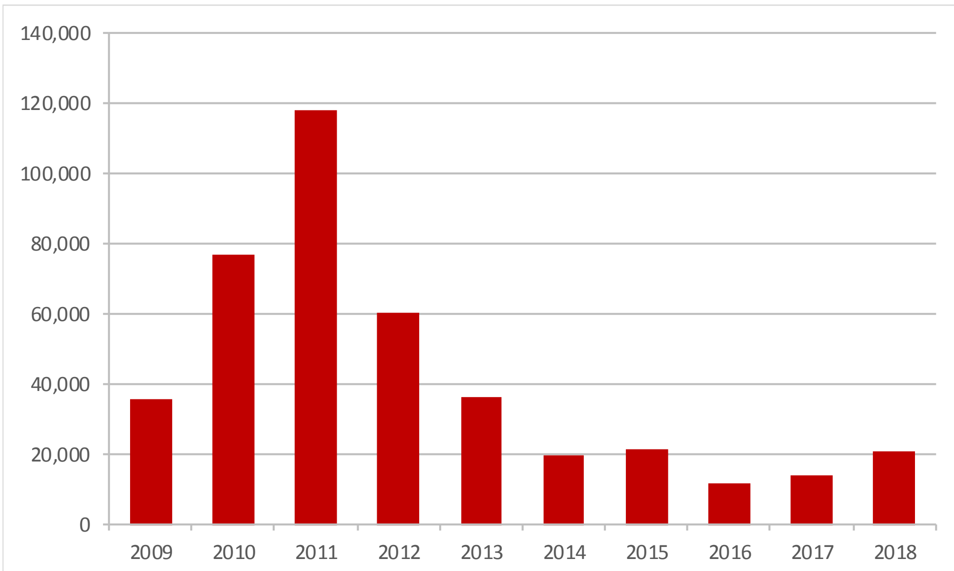


As shown in Figure III-4 above, the combined Sable Island and Deep Panuke average daily production ranged from approximately 100 MMcf/day to 200 MMcf/day over the 2015 to 2018 time period.[37] This loss of nearly 200 MMcf/day of production from Sable Island and Deep Panuke reduces the natural gas supply options in the regional market and places upward price pressure on New England gas price indices.

[36] Source: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports and Deep Panuke Monthly Production Reports.
[37] The average production over the past four years is well below the Sable Island peak production average of over 500 MMcf/day in 2002.

The other source of gas supply into Maritimes from Atlantic Canada is vaporized LNG from Canaport, which is largely provided as a winter peaking service. The pricing and availability of gas supplies into Canaport are subject to competing global markets for LNG such that the availability of gas supply from Canaport will be affected by international market dynamics for LNG. As illustrated in Figure III-5 below, the total annual volumes of LNG imports into Canaport have decreased significantly since their peak in 2011.

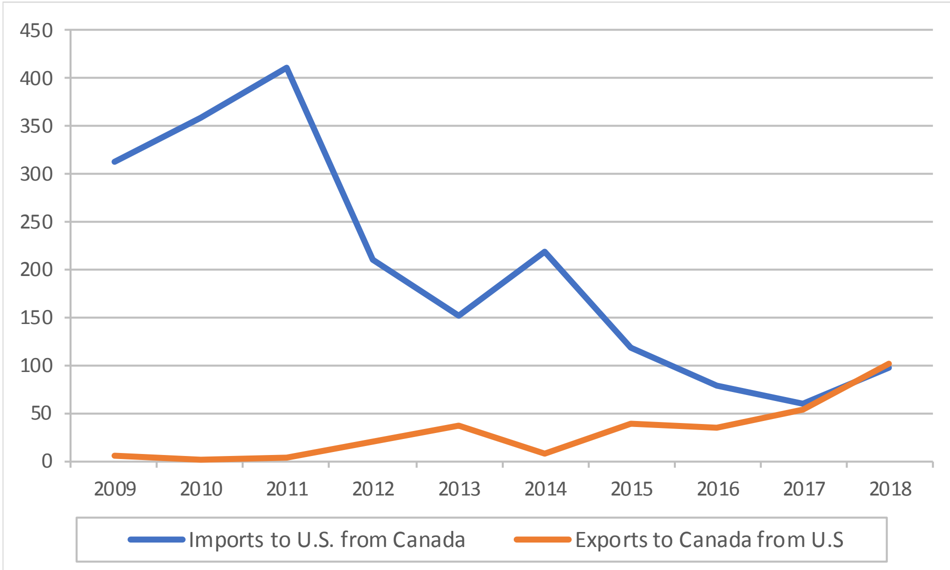
Figure III-5: Annual Canaport LNG Imports (MMcf)[38]



The decline in natural gas supplies available from Sable Island, Deep Panuke, and Canaport LNG has resulted in a changing flow pattern on Maritimes. Specifically, there are increasing volumes of natural gas being exported from the U.S. to Canada on Maritimes at the Calais, ME point[39] to meet the natural gas demand requirements of LDCs and end-users in Atlantic Canada. Figure III-6 below illustrates the increasing trend of volumes exported to Canada at Calais, and the declining volumes of natural gas imports to the U.S. from Canada at the Calais, ME point.

[38] Source: National Energy Board, LNG – Shipment Details, Canaport LNG Volumes.
[39] Calais, ME is defined by the U.S. Department of Energy as the U.S. point of entry/exit on the Maritimes pipeline system at the U.S./Canadian border.

Figure III-6: Average Daily Volumes at Calais, ME (MMcf/day)[40]



Notably, LDCs and end-users in Atlantic Canada have supported several recent pipeline capacity projects, by contracting for capacity on the Atlantic Bridge Project and the Portland XPress Project. Stated differently, the natural gas market participants in Atlantic Canada, recognizing the need to replace gas deliveries from historical supply sources (e.g., Sable Island and Deep Panuke), have executed precedent agreements for capacity on certain pipeline projects that are consistent with decisions made by the Company.

2. Significant Uncertainty Related to Supplies from Distrigas

Another primary source of natural gas supply to the New England region is imported LNG at the Distrigas facility in Everett, MA, which is now owned by Exelon Generation Company, LLC ("Exelon") and operated by Exelon's subsidiary, Constellation LNG, LLC ("CLNG").[41] As discussed below, CLNG has recently received approval for certain cost recovery strategies that may increase uncertainty with respect to the type of services and associated costs offered by the Distrigas facility. Figure III-7 below illustrates that the total annual volumes of imported LNG to the Distrigas facility have decreased significantly since 2008, with the annual imported LNG volumes at Distrigas averaging between 50,000 to 70,000 MMcf (or approximately 150 to 200 MMcf/day) over the past four years.

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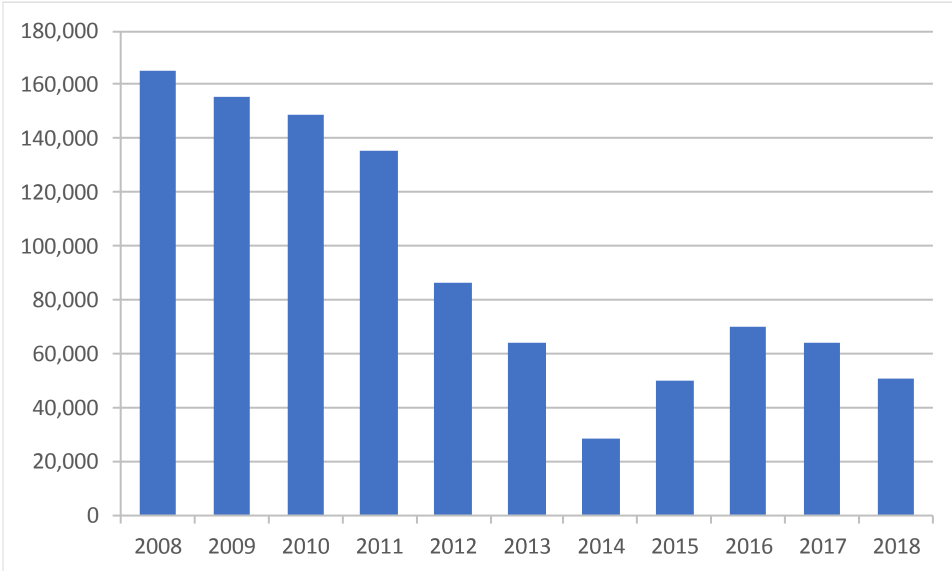
[40] Sources: U.S. Energy Information Administration, Calais, ME Natural Gas Pipeline Imports from Canada, March 29, 2019; and U.S. Energy Information Administration, Calais, ME Natural Gas Pipeline Exports to Canada, March 29, 2019.
[41] Exelon completed the acquisition of the Distrigas facility from ENGIE Gas & LNG LLC in October 2018.

Figure III-7: Annual Distrigas LNG Imports (MMcf)[42]



In addition to providing delivered natural gas supplies (i.e., vapor and liquid) to certain LDCs in the region, the Distrigas facility is the sole source of natural gas supply for Constellation Mystic Power, LLC ("Mystic") Units 8 and 9. In March 2018, Exelon filed a notice with the ISO New England to retire the Mystic 8 and 9 units, due to fuel security concerns; however, subsequent to that filing, the parties (i.e., Mystic, Exelon, and ISO New England) entered into a cost-of-service agreement to support the continued operation of the Mystic 8 and 9 units through March 2024. The Federal Energy Regulatory Commission ("FERC") approved the cost-of-service agreement subject to certain conditions in December 2018. Notwithstanding the cost of service agreement, the long-term service availability and associated price signals from CLNG are unknown, thus adding significant uncertainty with respect to the future availability and pricing of delivered natural gas supplies from the Distrigas facility.

3. Limited Pipeline Expansion Projects to Serve New England

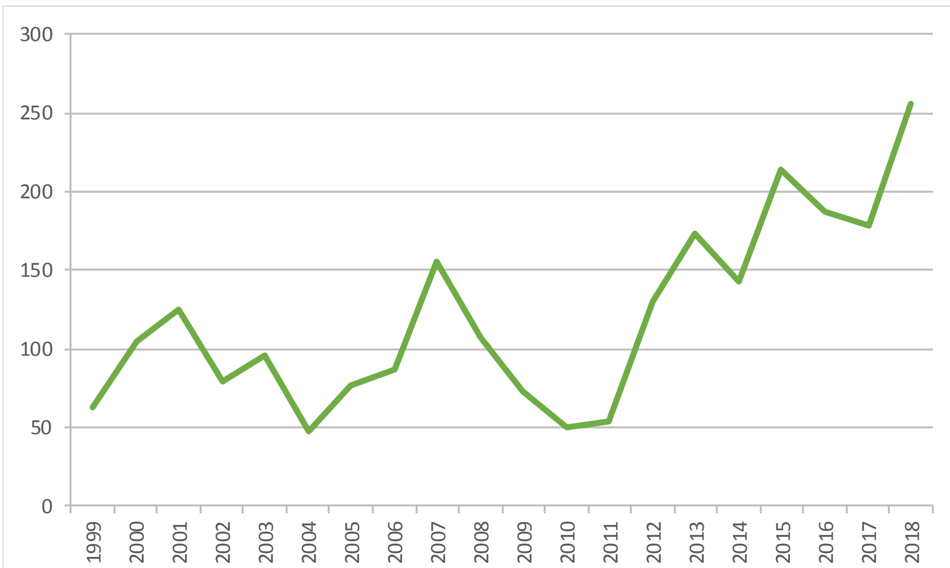
There have been limited pipeline capacity expansion projects to serve the New England region, in general, and the Company, in particular. Over the past two years, the successful pipeline projects in the region include: the Atlantic Bridge (partial in-service late 2017 to southern New England), Continent-to-Coast ("C2C") (in-service late 2017), and Portland XPress (Phase I in-service late 2018) projects. At this time, there are no prospects for new natural gas pipeline capacity into New England from the south (i.e., expansions on Tennessee or Algonquin). As discussed in the Company's petition for approval of the Portland XPress precedent agreement, the two major pipeline projects that were proposed, Tennessee's Northeast Energy Direct and Enbridge's Access Northeast projects, have been cancelled or suspended indefinitely. There are currently no new expansion projects announced on Algonquin; and the most recent proposed expansion on the Tennessee system is limited to the TGP 261 Upgrade Project, which

[42] Source: U.S. Department of Energy, LNG Annual Reports.

would transport natural gas from Dracut, Massachusetts to serve LDCs located in western Massachusetts (i.e., does not provide incremental supply to the region). The Westbrook XPress project is the only new pipeline project announced since the Portland XPress project that would be able to provide service to the Company and adds incremental supply/capacity to the New England region.

As a result of the successful development of the PNGTS C2C and Portland XPress (Phase I) projects, there have been increases in Canadian natural gas imports via PNGTS pipeline at the Pittsburg, NH interconnection with TransCanada. As illustrated in Figure III-8 below, the level of natural gas imports at Pittsburg, NH has increased to an average daily volume of approximately 255 MMcf/day in 2018. The Portland XPress (Phases II and III) and Westbrook XPress projects will further increase the volumes of natural gas imported from Canada at Pittsburg, NH.

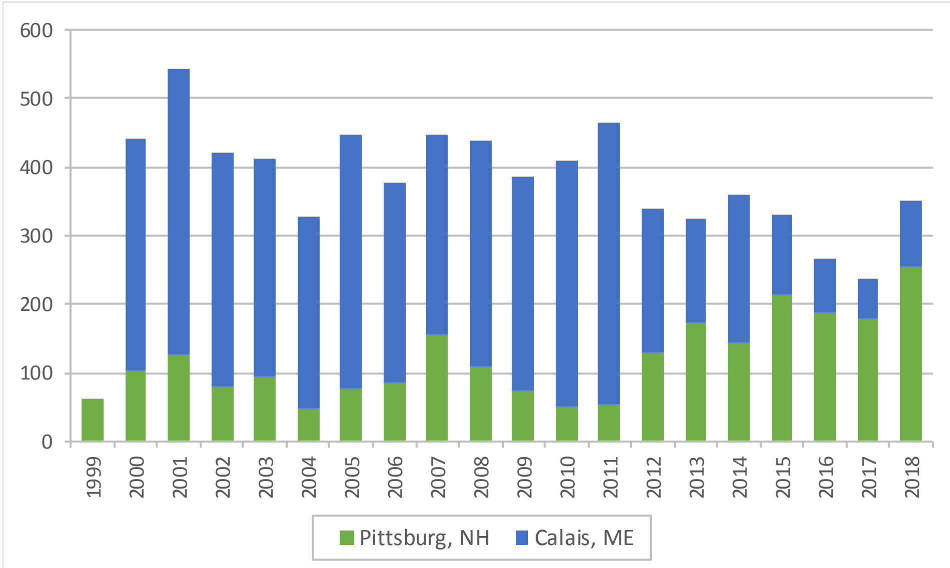
Figure III-8: Average Daily Volumes at Pittsburg, NH (MMcf/day)[43]



To provide more context regarding the importance of the recent PNGTS expansions, Figure III-9 below shows the contribution of natural gas deliveries to New England on PNGTS (i.e., imports at Pittsburg, NH) and Maritimes (i.e., imports at Calais, ME). Specifically, as illustrated in Figure III-9, the volumes of gas supplies imported at Pittsburg, NH on PNGTS have increased significantly and represent approximately 70 to 75 percent of the total volumes imported to the U.S. on the PNGTS and Maritimes systems over the past three years.

[43] Source: U.S. Energy Information Administration, Pittsburg, NH Natural Gas Pipeline Imports from Canada, March 29, 2019.

Figure III-9: Average Daily Volumes on PNGTS and Maritimes (MMcf/day)[44]



The proposed Westbrook XPress Project would increase the volumes of natural gas imported at Pittsburg, NH to the New England region. In addition, the proposed Westbrook XPress Capacity would provide Northern with additional access to the Dawn Hub in Ontario via the Enbridge and TransCanada systems. Over the past several years, Enbridge and TransCanada have successfully developed pipeline expansion projects increasing natural gas supplies to various markets including PNGTS, which increases the probability of a successful development for the proposed Westbrook XPress Project. As discussed in Docket 2018-00040 (i.e., the Portland XPress docket), Enbridge increased its Dawn to Parkway transmission capacity by approximately 20 percent from 2015 to 2017.[45] In mid-2018, Enbridge held an open season for up to 350,000 GJ/day of capacity beginning in 2021 and up to 250,000 GJ/day of capacity beginning in 2022 on the Dawn Parkway system. The Enbridge open season was held concurrently with the TransCanada new capacity open season for up to 30,000 GJ/day from Parkway to East Hereford beginning on November 1, 2022. The open season announcements are provided as Appendix 2-B (TransCanada) and Appendix 2-C (Enbridge).

As discussed above, while supplies into Maritimes from Atlantic Canada are ceasing or subject to global competition, natural gas supply available at Dawn continues to increase and diversify. These incremental natural gas supplies into Dawn include deliveries from the Rover and Nexus pipeline projects, as well as gas supply from producers in Western Canada who participated in TransCanada's Dawn Long-Term Fixed Price ("Dawn LTFP") service. The Rover and Nexus pipeline projects were placed in service between mid-2017 and 2018, and the Dawn LTFP service commenced in November 2017. Figure III-10 illustrates the various pipelines and gas supply basins that serve the Dawn Hub.

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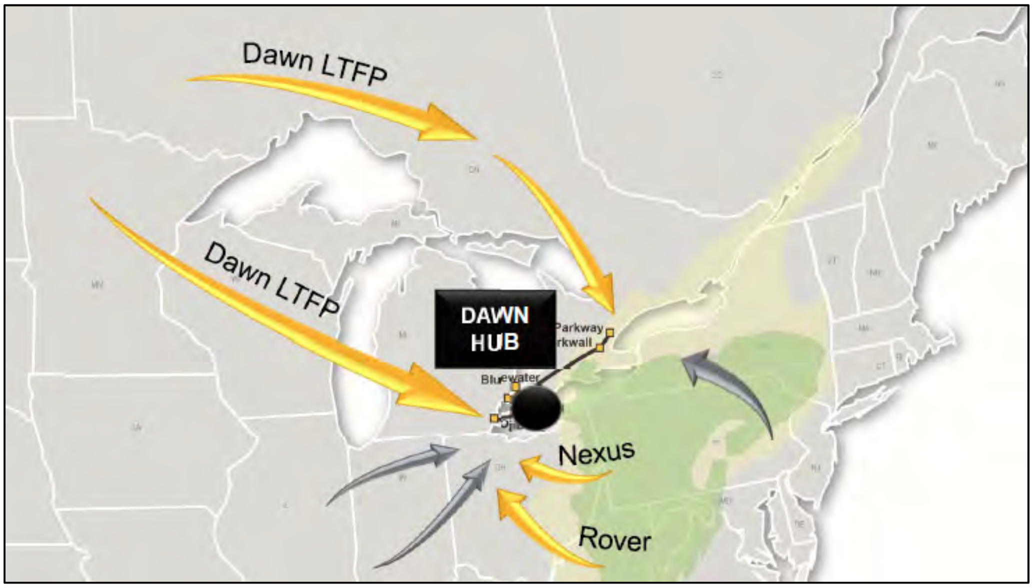
[44] Sources: U.S. Energy Information Administration, Pittsburg, NH Natural Gas Pipeline Imports from Canada, March 29, 2019; and U.S. Energy Information Administration, Calais, ME Natural Gas Pipeline Imports from Canada, March 29, 2019.
[45] Source: Union Gas presentation, "Dawn Hub – Crossroads of Supply & Demand", October 23, 2017, slide 11.

Figure III-10: Gas Flows to the Dawn Hub[46]



As a result of these projects, the Dawn Hub has more access to Marcellus/Utica and Western Canadian Sedimentary Basin ("WCSB") natural gas production, which are two of the primary gas supply basins in North America. Specifically, Figure III-11 below shows the projected increase in natural gas production from the WCSB; and Figure III-12 illustrates the significant increase in Appalachian (i.e., Marcellus and Utica) natural gas production. By 2050, the U.S. Energy Information Administration Annual Energy Outlook projects natural gas production in the Appalachian region to be greater than 50 Bcf/day.[47]

[46] Source: Enbridge Gas, Dawn Hub presentation.
[47] Source: U.S. Energy Information Administration, Annual Energy Outlook 2019, January 24, 2019.

Figure III-11: WCSB Projected Natural Gas Production (Bcf/day)[48]

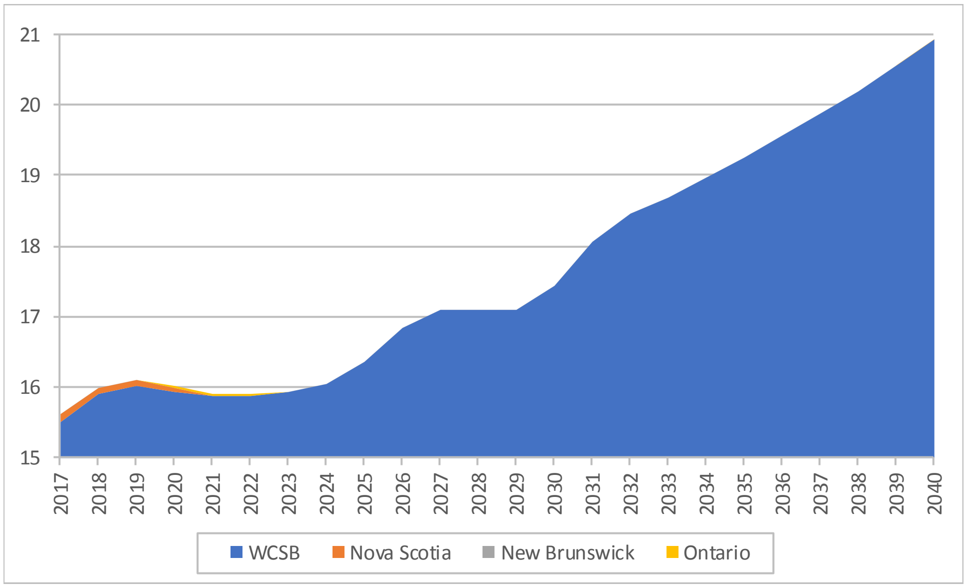
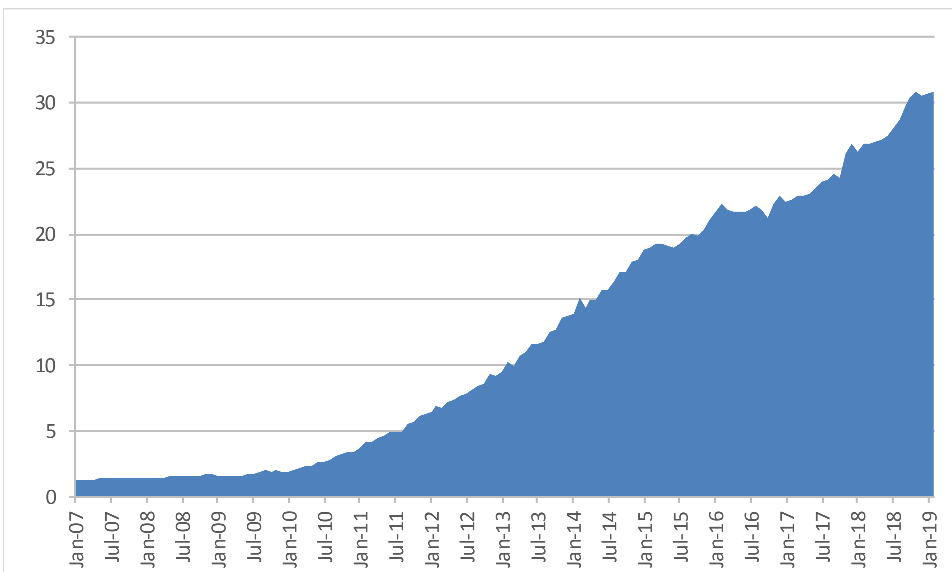


Figure III-12: Marcellus/Utica Historic Shale Gas Production (Bcf/day)[49]



Finally, the increase in supplies to the Dawn Hub has placed downward pressure on the natural gas prices, and increased price stability while maintaining liquidity at the Dawn price index (as discussed further in the following section).

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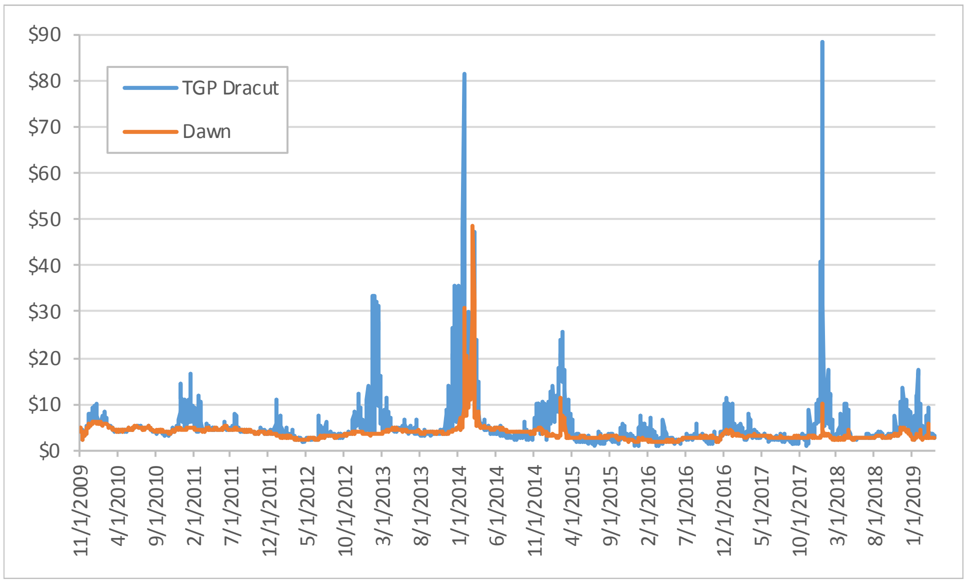
[48] Source: National Energy Board, Canada's Energy Future 2018: Energy Supply and Demand Projections to 2040, October 30, 2018.
[49] Source: U.S. Energy Information Administration, Drilling Productivity Report, March 18, 2019.

4. Natural Gas Price Implications

The regional natural gas market challenges for New England have resulted in high price levels, significant volatility, and liquidity issues at the various New England natural gas price indices. Figure III-13 below illustrates the high price levels of the TGP Dracut price index relative to Dawn Hub over the past ten years.

Figure III-13: Daily Spot Prices ($/MMBtu) – 2009/10 to 2018/19[50]



As shown in Figure III-13 above, the TGP Dracut price index experiences significant price spikes in the winter period. A broader comparison of the various New England delivered natural gas pricing indices (i.e., Algonquin City-gates ("ALGCG"), Tennessee Zone 6 ("TGP Z6"), TGP Dracut price indices) to the Dawn Hub price index not only further illustrates the lower prices at the Dawn Hub, but also shows the relatively lower volatility of the Dawn Hub (see Table III-6 below).

[50] Source: Based on ScottMadden, Inc.'s ("ScottMadden's") analysis of data from S&P Global Market Intelligence.

Table III-6: Average Winter Spot Prices and Volatility – 2009/10 to 2018/19[51]

	Average Winter Spot Prices ($/MMBtu)				Winter Price Volatility			
Winter	TGP Z6	ALGCG	TGP Dracut	Dawn	TGP Z6	ALGCG	TGP Dracut	Dawn
2009/10	$ 5.92	$ 5.96	$ 5.84	$ 5.19	115%	117%	111%	68%
2010/11	$ 6.52	$ 6.57	$ 6.46	$ 4.59	249%	227%	228%	23%
2011/12	$ 3.86	$ 3.86	$ 3.85	$ 3.24	171%	171%	180%	22%
2012/13	$ 9.31	$ 9.64	$ 9.28	$ 3.83	298%	312%	327%	20%
2013/14	$ 14.93	$ 15.09	$ 15.76	$ 8.06	472%	473%	452%	287%
2014/15	$ 8.88	$ 9.27	$ 8.95	$ 3.87	370%	385%	358%	143%
2015/16	$ 2.97	$ 3.02	$ 3.07	$ 2.10	272%	321%	267%	45%
2016/17	$ 4.82	$ 4.69	$ 4.92	$ 3.27	231%	268%	294%	48%
2017/18	$ 8.28	$ 8.13	$ 8.71	$ 3.08	421%	514%	418%	129%
2018/19	$ 5.45	$ 5.40	$ 5.77	$ 3.38	318%	327%	315%	108%

With respect to volatility,[52] as shown in Table III-6 above, over the past ten winter periods, the volatility level for the New England price indices have consistently exceeded 100% every winter, with average winter price levels exceeding $5/MMBtu in seven of the ten winters. In contrast, the Dawn price index has only one observation with relatively higher volatility, which reflected certain price spikes at Dawn in the colder-than-normal winter of 2013/14; three observations with volatility levels between 100% and 150% and price levels below $4/MMBtu; and six observations with volatility levels below 100% and prices levels between $2-6/MMBtu. Focusing on the average prices over the past five years, the average winter price at the Dawn Hub has been approximately $3/MMBtu below the prices of the New England indices.

Finally, in November 2018, the S&P Global Platts' price index for TGP Z6 was split into four price points (TGP Zone 6 delivered, TGP Zone 6 delivered North, TGP Zone 6 delivered South, and TGP Zone 6 (300 Leg) delivered), which will further impact the volatility and liquidity of Tennessee Zone 6 pricing. The level of liquidity of certain New England price indices relative to the Dawn price index is summarized in Table III-7 below.

[51] Source: Based on ScottMadden's analysis of data from S&P Global Market Intelligence.
[52] Price volatility calculated as the standard deviation of daily relative changes in natural gas prices. Source: U.S. Energy Information Administration, An Analysis of Price Volatility in Natural Gas Markets, August 2007.

Table III-7: S&P Global Platts – Liquidity Tiers – 2009/10 to 2018/19[53]

Split-Year (Nov-Oct)	Algonquin City-gates			Tennessee, Zone 6 (delivered)			Dawn, Ontario		
	Avg. Volume (MMBtu/ day)	Average Deals	Average Tier	Avg. Volume (MMBtu/ day)	Average Deals	Average Tier	Avg. Volume (MMBtu/ day)	Average Deals	Average Tier
2008/09	80,847	16	2	114,516	23	1	811,930	132	1
2009/10	125,733	21	1	141,427	26	1	594,463	110	1
2010/11	172,700	32	1	144,547	27	1	623,962	123	1
2011/12	291,095	51	1	154,991	33	1	508,674	97	1
2012/13	127,894	32	2	83,673	22	2	661,873	105	1
2013/14	54,547	15	2	34,223	6	3	394,948	92	1
2014/15	59,588	14	2	29,609	8	3	408,992	105	1
2015/16	56,667	14	2	25,167	8	2	435,083	102	1
2016/17	23,417	6	3	25,500	6	2	348,500	85	1
2017/18	81,117	26	2	15,158	6	3	433,342	103	1
Average	**108,378**	**24**	**2**	**64,108**	**14**	**2**	**476,922**	**101**	**1**

As shown in Table III-7, the Dawn index is currently, and has been consistently, rated a Tier 1 price index, which is the highest level of liquidity by S&P Global Platts; whereas, the ALGCG and TGP Z6 price indices have significantly lower volumes traded, number of transactions, and tier ratings (with Tier 3 being the lowest level of liquidity). While Dawn experiences significantly more trading activity that Tennessee and Algonquin, it is important to note that PNGTS does not have a published index and experiences significantly less trading activity than Tennessee and Algonquin. For example, from April 2018 through March 2019, PNGTS traded on Intercontinental Commodity Exchange ("ICE") only 116 out of 365 days, while Tennessee and Algonquin traded each day with published prices. Absent the WXP Capacity, Northern would be buying those volumes primarily on PNGTS, not Tennessee or Algonquin. As such, the natural gas supply pricing point for the WXP Capacity (i.e., the Dawn Hub), will provide the Company access to a growing natural gas supply pool, which has a highly liquid price signal.

[53] Source: S&P Global Platts, Liquidity in North American Monthly Gas Markets, February 2019. Data represents bidweek activity for first-of-month transactions.

IV. Demand Forecast

Key Takeaways

Key takeaways in this chapter include the following:

- *The Company's projection of growth in annual throughput under normal weather for the five year planning period is 1.5%, which is down from 1.9% observed over the prior five years. The Company's demand forecast is built at the Customer Segment level, with separate regression models for number of customers and use per customer, adjustments for expected energy efficiency savings, Company Use and Lost and Unaccounted for Gas.*
- *Energy Efficiency savings are expected to reduce forecasted throughput under normal weather by nearly 1.0 Bcf over the five year planning period, reducing the throughput forecast in the Maine Division from 1.8% to 1.6% and in the New Hampshire Division from 1.9% to 1.4%.*
- *The Company continues to use a 30 year weather history to perform weather adjustment calculations. Average temperatures observed in the Maine Division have declined steadily since the 1960s, however the pace of warming appears to be slowing. In the New Hampshire Division average temperatures have been stable for the past 4 decades.*

A. Introduction

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 and results of customer segment forecasts and expected energy efficiency savings, then presents the normal year throughput forecast over the five-year planning horizon covering the gas years of 2019/20 through 2023/24.[54]

Section V, Planning Load Forecast, documents the development of the design year and design day throughput forecasts, and the reduction for capacity exempt demand from the throughput forecasts to yield 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 and Normal Year Throughput forecast results;

[54] A gas-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.

Part C, Customer Segment Forecasts, describes the forecasting methodology, data utilized, including an analysis of climate change trends, discussion of key drivers in the forecast models chosen, normal weather demand results and adjustments for energy efficiency for each Customer Segment;

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, Energy Efficiency Impact on Forecast, shows how much higher the Normal Year Throughput forecast would be without projected energy efficiency savings.

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 2019/20 through 2023/24 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. There are no distinctions made between Sales Service and Transportation Service demands in the development of the customer segment demand models and the calculation of Normal Year Throughput.

Table IV-1: Forecast Terminology[55]

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	Aggregate demand of a defined group of customer classes measured at the customer meter on a billing period basis, generally reported in Therms
Throughput (TPUT)	Aggregate usage measured at the gate station or production of on-system gas on a calendar period basis, including Demand, Company Use and Lost and Unaccounted For Gas, generally reported in Dth

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

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 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 to yield expected net demand.[56] The Company made no explicit out of model adjustments, such as for marketing efforts. Customer net demand from each segment was tallied and adjusted further for Company Use and lost and unaccounted for gas to estimate Normal Year Throughput, which is total usage at the Company's gate stations on a calendar month basis under normal weather conditions.

As shown in Table IV-2, which reflects both the Maine Division and the New Hampshire Division, Northern's customer count is projected to increase at an average annual rate of 1.7 percent which reflects the addition of approximately 5,800 customers over the forecast period, which is consistent with prior results.

Table IV-2: Northern Projected Customer Counts

Gas Year	Residential Customers	C&I LLF Customers	C&I HLF Customers	Company Customers
2014/15	46,137	13,352	2,273	61,762
2015/16	47,094	13,445	2,193	62,732
2016/17	47,965	13,567	2,199	63,731
2017/18	49,025	13,767	2,245	65,038
2018/19	50,149	13,880	2,346	66,376
CAGR	2.1%	1.0%	0.8%	1.8%
Gas Year	Residential Customers	C&I LLF Customers	C&I HLF Customers	Company Customers
2019/20	51,141	13,997	2,370	67,508
2020/21	52,171	14,109	2,393	68,673
2021/22	53,208	14,221	2,415	69,844
2022/23	54,250	14,331	2,438	71,019
2023/24	55,298	14,440	2,460	72,199
CAGR	2.0%	0.8%	0.9%	1.7%

Table IV-3 presents the forecast of Northern's Normal Year Throughput. Normal Year Throughput is calculated as the sum of customer segment demand net of incremental energy efficiency

[56] 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.

savings, which is developed in therms on a billing cycle (BC) basis then converted to Dth on a calendar (Cal) basis, plus Company use and lost and unaccounted for gas. Normal Year Throughput is projected to increase at an average annual rate of about 1.5 percent, resulting in approximately 1.5 Bcf of additional annual throughput by the end of the five year planning horizon.

Table IV-3: Northern Normal Year Throughput (Dth)

Gas Year	Company Net Demand (Th)	Company Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Normal Year Throughput
2014/15	185,272,780	18,571,072	11,538	335,883	18,918,493
2015/16	183,988,573	18,433,092	10,357	332,682	18,776,131
2016/17	186,487,333	18,684,753	10,522	337,305	19,032,580
2017/18	192,974,928	19,352,052	12,371	349,492	19,713,915
2018/19	199,178,860	19,988,047	12,281	360,924	20,361,252
CAGR	1.8%	1.9%	1.6%	1.8%	1.9%
Gas Year	Company Net Demand (Th)	Company Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Normal Year Throughput
2019/20	202,245,156	20,283,036	11,899	366,172	20,661,106
2020/21	205,248,510	20,585,154	11,899	371,646	20,968,698
2021/22	208,472,790	20,908,599	11,899	377,560	21,298,057
2022/23	211,622,510	21,224,854	11,899	383,319	21,620,071
2023/24	214,840,012	21,547,940	11,899	389,217	21,949,056
CAGR	1.5%	1.5%	0.0%	1.5%	1.5%

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 Customers
- C&I Low Load Factor ("LLF")[57] Total Customers (i.e., Sales and Transportation)
- C&I High Load Factor ("HLF") Total Customers (i.e., Sales and Transportation)

The demand forecasts for the three Residential and C&I Customer Segments are based on separate econometric models for number of customers and use per customer. Thus, in total, six separate Residential and C&I models were developed for each Division. Currently, there are no Special Contract customers in the Maine Division and there are two Special Contract customers in the New

[57] 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.

Hampshire Division, which were included in the New Hampshire C&I High Load Factor Customer Segment. 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.

The Customer Segment demand forecast models were developed using regression analysis, based on accepted statistical techniques.[58] For the Customer Segment forecasts, regression analysis on monthly frequency data 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, employment levels, time based variables, and population). 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 November 2014 through March 2019.

All regression analysis was conducted using the EViews software package. The "Statistical Techniques and Glossary" section of Appendix 1 provides a full description of the modeling process used to develop the regression models, and also includes all output for the regression models and statistical tests conducted.

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 November 2014 through March 2019, including demand, measured in therms and number of customers 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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58 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.

Table IV-4: Customer Segment Definitions

Class ME	Class NH	Class Description	Customer Segment
R-2	R-5, R-10	Residential Heating	Residential
R-1	R-6, R-11	Residential Non-Heating	
G-40	G-40	C&I Low Annual Use, High Peak Period/ Winter Use	C&I Low Load Factor (LLF)
G-41	G-41	C&I Medium Annual Use, High Peak Period/ Winter Use	
G-42	G-42	C&I High Annual Use, High Peak Period/ Winter Use	
G-50	G-50	C&I Low Annual Use, Low Peak Period/ Winter Use	C&I High Load Factor (HLF)
G-51	G-51	C&I Medium Annual Use, Low Peak Period/ Winter Use	
G-52	G-52	C&I High Annual Use, Low Peak Period/ Winter Use	

b) Weather Variables

Historical daily effective degree day ("EDD") data for the 30 year historical period of November 1, 1988 through October 31, 2018 was utilized by the Company for the Maine Division (measured at the Portland, Maine weather station PWM) and for the New Hampshire Division (measured at the Portsmouth, New Hampshire weather station PSM). 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.[59]

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 in cycles every 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.

[59] The Company used the average temperature and wind speeds to produce daily EDD for each Gas Day for each 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

Historical billing cycle monthly EDD values for the period November 2014 through March 2019 were calculated and used to measure the effect of temperature on natural gas use in the Customer Segment use per customer regression models.[60] 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 EDD pattern was used to restate historical period usage by customer segment for assessment purposes. The normal year and design year EDD patterns were applied to the customer segment models to estimate normal year and design year demand. These EDD patterns are described further and presented in Section V, Planning Load Forecast.

c) Climate Change Analysis

The Company looked at climate change in terms of whether long-term trends in the statistical distribution of weather patterns are impacting the predictive power of historical weather data depending on the length of history used. A statistical analysis was prepared for this IRP to determine whether there is a difference in the ability of distributions comprised of 10, 20, or 30 years of historical EDD data to predict the weather (EDD) in the next year, and if so, which was the best predictor. If climate change is trending significantly, then the 10 year distribution may be a better predictor as it is based on a shorter period more reflective of recent experience; whereas, if climate change is not trending significantly, then the 30 year distribution may be a better predictor as it includes more history providing more statistical significance for establishing planning standards. To test this hypothesis, rolling 10, 20, and 30 year average EDD were calculated and compared to the EDD for the following year. For example, 10, 20, and 30 year averages were calculated for the year ending 2010 and compared with the actual EDD that occurred in 2011. This analysis was conducted for all years available.

The predictive capability of each distribution (i.e., rolling average) was determined by comparing the standard error associated with each rolling average. The standard error (or, root mean square error (“RMSE”)) measures the average error between the rolling average and the actual EDD. The lowest standard error determines the best predictor of the next year’s EDD. Analyses of 10, 20, and 30 year standard errors were prepared using annual (gas year) EDD, winter (November to March) EDD, January EDD, and Max Daily EDD. Results are presented in Table IV-5 below.

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

Table IV-5: Climate Change Analysis – By Division

Maine Results- Most Recent 27 Gas Years

	Standard Error (RSME)			% Improvement over 30 Year	
	10 Year Ave	20 Year Ave	30 Year Ave	10 Year Ave	20 Year Ave
Gas Year	470.7	494.7	554.7	15.1%	10.8%
Winter	399.3	401.6	424.0	5.8%	5.3%
January	147.0	147.4	152.3	3.4%	3.2%
Max Daily	5.6	5.6	5.8	3.0%	3.4%

New Hampshire Results- Most Recent 27 Gas Years

	Standard Error (RSME)			% Improvement over 30 Year	
	10 Year Ave	20 Year Ave	30 Year Ave	10 Year Ave	20 Year Ave
Gas Year	477.0	467.0	464.5	-2.7%	-0.5%
Winter	425.4	414.4	409.6	-3.9%	-1.2%
January	158.8	155.4	153.5	-3.5%	-1.2%
Max Daily	6.5	6.4	6.3	-2.6%	-0.4%

The Winter period, then progressing to January and ultimately the Max Daily are increasingly critical periods for resource planning purposes since these are the periods with the greatest consumption levels and consequently the greatest resource constraints. As highlighted above, for the Maine Division, the 10 or 20 year average is a better predictor of the following year EDD than the 30 year average. For the New Hampshire Division, the 10, 20, and 30 year averages are generally good at predicting the following year EDD, with the 30 year average producing slightly better results.

Further analysis was conducted by comparing the average EDD by decade over the previous 6 decades[61] for monthly EDD, Winter (November to March) EDD, Summer (April to October) EDD, Gas Year EDD and Max Daily EDD, as presented in Table IV-6 below. The general trend has been declines in average EDD from decade to decade, especially in Maine, with Summer EDD actually dropping more than Winter EDD on a percentage basis in both states. Winter EDD in New Hampshire appear relatively steady over the past 4 decades. Bucking the trend of decline, average Max Daily EDD during the 2010s was higher than had been seen in Maine since the 1980s and in New Hampshire since the 1960s. Despite the general decrease in annual and winter EDD over time, the rate of change over the most recent three decades spanning the 1990s through the 2010s has been significantly slower than over the preceding three decades spanning the 1960s through the 1980s.

[61] The available data includes 58 years and 59 winters. The data begins November 1961, so the 1960s decade includes only 9 years. Similarly, the data set ends May 2019, so the 2010s decade includes 9 winters and 8 summers.

Table IV-6: Average EDD by Decade – By Division

	Maine EDD by Decade						New Hampshire EDD by Decade					
	1960s	1970s	1980s	1990s	2000s	2010s	1960s	1970s	1980s	1990s	2000s	2010s
Nov	893	852	848	835	782	810	819	769	768	776	744	776
Dec	1,352	1,317	1,292	1,166	1,191	1,147	1,265	1,214	1,192	1,108	1,153	1,098
Jan	1,486	1,495	1,446	1,403	1,384	1,342	1,388	1,364	1,335	1,339	1,335	1,303
Feb	1,344	1,286	1,164	1,189	1,178	1,164	1,265	1,196	1,085	1,124	1,136	1,118
Mar	1,124	1,086	1,059	1,048	1,047	1,059	1,048	998	977	990	999	1,020
Apr	753	734	695	699	652	667	670	649	614	622	600	610
May	427	399	380	379	374	341	352	308	312	315	322	299
Jun	122	140	123	98	114	108	91	84	96	68	88	90
Jul	27	21	17	15	17	8	14	8	10	10	11	7
Aug	51	42	40	23	23	8	34	28	29	14	19	8
Sep	241	224	200	200	134	137	193	165	154	161	117	119
Oct	543	586	545	535	512	441	455	499	471	469	473	416
Winter	6,199	6,036	5,808	5,641	5,582	5,521	5,785	5,541	5,356	5,336	5,367	5,314
Summer	2,164	2,145	2,001	1,948	1,826	1,710	1,810	1,740	1,687	1,659	1,631	1,549
Gas Year	8,362	8,181	7,809	7,589	7,407	7,231	7,595	7,281	7,043	6,995	6,997	6,863
Max Daily	76.4	73.0	71.8	69.4	66.7	70.2	75.6	69.2	69.2	69.0	66.7	70.8

Based on an examination of these results and the desire to use consistent data sets across both Divisions, it was determined that the 30 year distribution was the most appropriate for predicting the following year EDD at this time. Therefore, the Normal Year EDD forecast and the Design Year and Design Day planning standard EDD were developed using a database of the most recent 30 years of weather data for both the Maine and New Hampshire Divisions.

d) 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 November 2014 through March 2019 (the "historical period") and forecast data was provided from April 2019 through October 2043. The data include employment, population, and housing statistics specific to each state. Due to volatility in pricing, particularly over long periods of time, the Company has removed pricing variables from its Use Per Customer models. Table IV-7 summarizes the Global Insight economic and demographic data evaluated while developing the Customer Segment models.

Table IV-7: Global Insight Variables

Total Population (Thousands)
Households (Thousands)
Housing Starts, Total Private
Labor Force (Thousands)
Employment, Non-manufacturing (Thousands)
Employment, Manufacturing (Thousands)

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 Company's customers fund Energy Efficiency programs administered by Efficiency Maine. Savings from energy efficiency measures installed before the forecast period (prior to April 2019) are assumed to be built into the history of actual customer demand. That is, in the absence of historical energy efficiency measures having been installed, gas sales during the historical period would have been higher than actually occurred. Projected incremental energy efficiency savings, reflecting measures installed during and after April 2019, are tallied and deducted from the Customer Segment demand forecasts. The resulting forecasts after reduction for energy efficiency savings are referred to as "Net Demand".

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-8: Structure of Customer Segment Model Results Section

Sub-Section	Description
a) Residential Forecast	Customer Model results times Use per Customer results
b) Residential Energy Efficiency Savings	Incremental Savings from Residential EE Programs
c) Residential Net Demand	= Residential Forecast - Residential EE Savings
d) C&I Low Load Factor (LLF) Forecast	Customer Model results times Use per Customer results
e) C&I High Load Factor (HLF) Forecast	Customer Model results times Use per Customer results
f) C&I Energy Efficiency Savings	Incremental Savings from C&I EE Programs
g) C&I Net Demand	= C&I LLF Forecast + C&I HLF Forecast - C&I EE Savings
h) Incremental Energy Efficiency Savings	= Residential EE Savings + C&I EE Savings
i) Customer Segment Net Demand	= Residential Net Demand + C&I Net Demand

a) Residential Customer Segment Forecast – Maine Division

The Residential Segment 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 customers, total population was statistically significant. In the final regression equation that was selected to predict Residential use per customer, billing 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-9 below summarizes the Residential customer segment model results for customer growth, use per customer, and residential demand for the forecast period as compared to the historical reference period.[62]

[62] 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.

Table IV-9: Residential Customer Segment Forecast – Maine Division

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2014/15	21,745	736	15,996,883
2015/16	22,172	699	15,498,142
2016/17	22,494	719	16,178,233
2017/18	22,877	727	16,624,507
2018/19	23,322	744	17,347,537
CAGR	1.8%	0.3%	2.0%
Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2019/20	23,686	741	17,552,263
2020/21	24,068	745	17,923,115
2021/22	24,451	748	18,297,755
2022/23	24,835	752	18,676,171
2023/24	25,221	756	19,058,701
CAGR	1.6%	0.5%	2.1%

Over the forecast period, the number of Maine Residential customers is expected to grow at an annual rate of 1.6% compared to a growth rate of 1.8% over the historical reference period. Use per customer for the Residential Customer Segment is expected to increase by 0.5% annually compared to the historical reference period rate of 0.3%. The Residential demand forecast was calculated by multiplying the forecasted number of Residential customers each month by the forecasted Residential use per customer for that month. Over the forecast period, Residential demand is expected to increase at effectively the same rate as over the historical reference period.

b) Residential Energy Efficiency Savings – Maine Division

The Residential demand forecast was reduced by expected incremental energy savings associated with Residential energy efficiency program targets. The estimated incremental energy savings associated with current Residential energy efficiency programs for the forecast period for the Maine Division are listed in the tables below. Historical energy efficiency savings are assumed to already be reflected in metered consumption. Although previously installed efficiency measures will continue to achieve savings, those savings are already embedded in historical usage. Since the historical data used for the demand forecast extends through March 2019, incremental efficiency savings are those associated with measures expected to be installed beginning in April 2019. In determining the pattern and level of efficiency savings, Northern assumed that savings targets are met, that measures are installed ratably over twelve months each year, and that realized savings vary with customer demand patterns. For example, realized savings are expected to be very low in July and August when customer consumption is low and at their highest in January and February when customers use the most natural gas.

Table IV-10 below provides the annual energy efficiency savings targets for Residential EE programs operated by Efficiency Maine, as reflected in the 2020-2022 Proposed Triennial Plan. Northern assumed that target savings would be achieved and that savings would continue throughout the planning period at the level of the last year projected (2022). Since Efficiency Maine administers their programs at the state level, Northern assumed that 66 percent of natural gas related savings projections would apply to Northern customers.

Table IV-10: Residential Energy Efficiency Savings – Maine Division (Annual MMBtu)[63]

	Forecast FY 2019	Forecast FY 2020	Forecast FY 2021	Forecast FY 2022	Forecast FY 2023	Forecast FY 2024
Retail Initiatives	0	166	166	166	166	166
Home Energy Savings Program	4,545	4,042	3,980	3,887	3,887	3,887
Low Income Initiatives	2,954	2,931	2,931	2,900	2,900	2,900
Residential Total	7,499	7,138	7,076	6,953	6,953	6,953
NUI Share (66%)	4,949	4,711	4,670	4,589	4,589	4,589

Table IV-11 demonstrates the conversion of fiscal year energy efficiency savings targets into monthly savings that correlate with Residential customer consumption through the first gas year, which runs from November 2019 through October 2020. The calculation shown in Table IV-11 is carried forward throughout the forecast period. Target savings are shown in MMBtu, so the values shown in Table IV-10 were multiplied by 10 to convert to therms (Th). Measures are assumed to be installed ratably, so the annual savings targets are divided by 12 and listed for each month of the fiscal year. A cumulative tally of the annual savings capability installed each month is calculated then multiplied by the Residential monthly demand pattern. The demand pattern is based on a 4 year history of weather adjusted normal demand from November 2014 through October 2018. The result is the incremental efficiency savings each month. The efficiency savings for the gas year of 2019/20 tallied at the bottom of Table IV-11 tie to the Residential EE Savings shown in the table that follows.

[63] Data from Appendix B of Proposed Triennial Plan for Fiscal Years 2020-2022, Efficiency Maine Trust, October 3, 2018.

Table IV-11: Residential Incremental EE Savings – Maine Division (Th)

Month	New Installs	Cumulative Installs	Residential Demand Pattern	Incremental EE Savings
Jan 2019	4,124		17.9%	
Feb 2019	4,124		18.0%	
Mar 2019	4,124		15.0%	
Apr 2019	4,124	4,124	10.7%	443
May 2019	4,124	8,249	5.9%	488
Jun 2019	4,124	12,373	3.2%	397
Jul 2019	3,926	16,299	2.0%	319
Aug 2019	3,926	20,225	1.8%	365
Sep 2019	3,926	24,151	1.8%	447
Oct 2019	3,926	28,077	3.4%	949
Nov 2019	3,926	32,003	7.1%	2,261
Dec 2019	3,926	35,929	13.2%	4,740
Jan 2020	3,926	39,855	17.9%	7,150
Feb 2020	3,926	43,781	18.0%	7,869
Mar 2020	3,926	47,707	15.0%	7,144
Apr 2020	3,926	51,633	10.7%	5,546
May 2020	3,926	55,559	5.9%	3,285
Jun 2020	3,926	59,485	3.2%	1,911
Jul 2020	3,892	63,377	2.0%	1,239
Aug 2020	3,892	67,269	1.8%	1,214
Sep 2020	3,892	71,161	1.8%	1,316
Oct 2020	3,892	75,053	3.4%	2,537
Gas Year 2019/20				46,211

c) Residential Customer Segment Net Demand – Maine Division

Residential Net Demand for the Maine Division is summarized in Table IV-12 below as Residential customer segment demand less expected residential energy efficiency savings (“EE Savings”). Residential Net Demand is projected to increase by 1.8 percent annually over the forecast period. As highlighted above, the primary driver of residential customer growth is total population growth and the primary driver of residential use per customer is weather.

Table IV-12: Residential Customer Segment Net Demand (Th) - Maine Division

Gas Year	Residential Demand	Residential EE Savings	Residential Net Demand
2019/20	17,552,263	-46,211	17,506,052
2020/21	17,923,115	-93,022	17,830,093
2021/22	18,297,755	-139,158	18,158,597
2022/23	18,676,171	-185,048	18,491,123
2023/24	19,058,701	-230,938	18,827,763
CAGR	2.1%	49.5%	1.8%

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

The C&I LLF 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 customers, total population was statistically significant. In the final regression equation that was selected to predict C&I LLF 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-13 below summarizes the C&I LLF customer model results for customer growth, use per customer, and C&I LLF demand for the forecast period as compared to the historical reference period.

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

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2014/15	7,801	8,208	64,031,625
2015/16	7,801	7,846	61,204,464
2016/17	7,892	7,878	62,173,764
2017/18	8,020	7,982	64,016,253
2018/19	8,094	8,126	65,772,658
CAGR	0.9%	-0.3%	0.7%
Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2019/20	8,151	8,214	66,949,327
2020/21	8,218	8,316	68,343,472
2021/22	8,286	8,419	69,752,875
2022/23	8,353	8,521	71,177,429
2023/24	8,421	8,623	72,617,507
CAGR	0.8%	1.2%	2.1%

Over the forecast period, the number of Maine C&I LLF customers is projected to increase by 0.8% annually compared to the growth rate of 0.9% over the historical reference period. Use per customer for the C&I LLF Customer Segment is expected to grow by 1.2% annually over the forecast. Although the historical use per customer had a growth rate of -0.3% over the historical reference period, the growth rate for the last four years of the historical period, 2015/16 through 2018/19, was 1.2%, which is reflected in the forecast. The C&I LLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I LLF customers each month by the forecasted C&I LLF use per customer for that month. Over the forecast period, C&I LLF demand is expected to increase by 2.1% compared to 0.7% growth seen in the historical reference period; note however that the growth rate for the last four years of the historical period, 2015/16 through 2018/19, was 2.4%, which is reflected in the forecast.

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

The Maine C&I HLF Customer Segment encompasses about 15 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 60 percent more than Residential segment. In the final regression equation that was selected to predict C&I HLF customers, a linear trend variable was statistically significant. In the final regression equation that was selected to predict C&I HLF 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-14 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-14: C&I HLF Customer Segment Forecast – Maine Division

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2014/15	1,143	21,267	24,316,750
2015/16	1,089	23,709	25,816,858
2016/17	1,097	23,416	25,683,533
2017/18	1,150	23,584	27,122,080
2018/19	1,193	23,581	28,130,733
CAGR	1.1%	2.6%	3.7%
Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2019/20	1,204	23,734	28,566,539
2020/21	1,216	23,632	28,726,165
2021/22	1,228	23,689	29,079,145
2022/23	1,240	23,663	29,330,798
2023/24	1,252	23,671	29,625,469
CAGR	1.0%	-0.1%	0.9%

Over the forecast period, the number of Maine C&I HLF customers is projected to grow by 1.0 percent annually, compared to 1.1 % growth experienced over the historical reference period. Use per customer for the C&I HLF Customer Segment is expected to remain essentially unchanged over the forecast period. Although the historical use per customer had a growth rate of 2.6% over the historical reference period, the growth rate for the last four years of the historical period, 2015/16 through 2018/19, was -0.2%, which is reflected in the forecast. The C&I HLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I HLF customers each month by the forecasted C&I HLF use per customer for that month. Over the forecast period, C&I HLF demand growth is expected to increase at an average annual rate of about 1 percent, compared to the historical growth rate of 3.7 percent.

f) C&I Energy Efficiency Savings – Maine Division

Table IV-15 below provides the annual energy efficiency savings targets for C&I EE programs operated by Efficiency Maine, as reflected in the 2020-2022 Proposed Triennial Plan. Northern assumed that target savings would be achieved and that savings would continue throughout the planning period at the level of the last year projected (2022). Since Efficiency Maine administers their programs at the state level, Northern assumed that 66 percent of natural gas related savings projections would apply to Northern customers.

Table IV-15: C&I Energy Efficiency Savings – Maine Division (Annual MMBtu)

	Forecast FY 2019	Forecast FY 2020	Forecast FY 2021	Forecast FY 2022	Forecast FY 2023	Forecast FY 2024
C&I Custom Program	12,371	3,134	3,134	3,134	3,134	3,134
C&I Prescriptive Program	43,651	19,244	19,244	19,244	19,244	19,244
Distributor Initiatives		4,119	4,119	4,119	4,119	4,119
C&I Total	56,022	26,496	26,496	26,496	26,496	26,496
NUI Share (66%)	36,974	17,488	17,488	17,488	17,488	17,488

Table IV-16 provides a similar conversion of fiscal year energy efficiency savings targets to monthly savings for C&I customers to the conversion provided in Table IV-11 for Residential customers. Again, target savings are shown in MMBtu, so the values shown in Table IV-10 were multiplied by 10, and measures are assumed to be installed ratably, so the annual savings targets are divided by 12. A cumulative tally of the annual savings capability installed each month is calculated then multiplied by the C&I monthly demand pattern to yield the incremental efficiency savings each month. The efficiency savings for the gas year of 2019/20 tallied at the bottom of Table IV-11 tie to the C&I EE Savings shown in the table that follows.

Table IV-16: C&I Incremental EE Savings – Maine Division (Th)

Month	New Installs	Cumulative Installs	C&I Demand Pattern	Incremental EE Savings
Jan 2019	30,812		14.2%	
Feb 2019	30,812		13.7%	
Mar 2019	30,812		12.6%	
Apr 2019	30,812	30,812	9.5%	2,917
May 2019	30,812	61,624	6.5%	3,993
Jun 2019	30,812	92,436	4.7%	4,329
Jul 2019	14,573	107,009	4.2%	4,509
Aug 2019	14,573	121,582	4.2%	5,061
Sep 2019	14,573	136,155	4.1%	5,628
Oct 2019	14,573	150,728	6.0%	9,031
Nov 2019	14,573	165,301	8.5%	14,120
Dec 2019	14,573	179,874	11.8%	21,180
Jan 2020	14,573	194,447	14.2%	27,668
Feb 2020	14,573	209,020	13.7%	28,662
Mar 2020	14,573	223,593	12.6%	28,193
Apr 2020	14,573	238,166	9.5%	22,546
May 2020	14,573	252,739	6.5%	16,377
Jun 2020	14,573	267,312	4.7%	12,520
Jul 2020	14,573	281,885	4.2%	11,877
Aug 2020	14,573	296,459	4.2%	12,342
Sep 2020	14,573	311,032	4.1%	12,856
Oct 2020	14,573	325,605	6.0%	19,509
Gas Year 2019/20				227,852

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

C&I Total Net Demand for the Maine Division is summarized in Table IV-17 below as the sum of the C&I LLF customer segment demand and the C&I HLF customer segment demand less expected C&I Total energy efficiency savings. C&I Total Net Demand is projected to increase by 1.5% annually over the forecast period.

Table IV-17: C&I Customer Segment Net Demand (Th) - Maine Division

Gas Year	C&I LLF Demand	C&I HLF Demand	C&I Total EE Savings	C&I Total Net Demand
2019/20	66,949,327	28,566,539	-227,852	95,288,013
2020/21	68,343,472	28,726,165	-402,729	96,666,908
2021/22	69,752,875	29,079,145	-577,605	98,254,415
2022/23	71,177,429	29,330,798	-752,482	99,755,746
2023/24	72,617,507	29,625,469	-927,358	101,315,618
CAGR	2.1%	0.9%	42.0%	1.5%

h) Customer Segment Net Demand Forecast – Maine Division

The result of the Maine Division customer segment modeling is presented below in Table IV-18, where the demand determined by customer segment assuming normal weather and reduced for energy efficiency savings is tallied for the entire Division.

Table IV-18: Customer Segment Net Demand (Th) - Maine Division

Gas Year	Residential Normal Net Demand	C&I Normal Net Demand	Division Normal Net Demand
2019/20	17,506,052	95,288,013	112,794,065
2020/21	17,830,093	96,666,908	114,497,001
2021/22	18,158,597	98,254,415	116,413,011
2022/23	18,491,123	99,755,746	118,246,869
2023/24	18,827,763	101,315,618	120,143,381
CAGR	1.8%	1.5%	1.6%

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.

The Company regularly implements Energy Efficiency under programs developed in coordination with the other New Hampshire gas and electric utilities. Savings from energy efficiency measures installed during the historical period (through March 2019) are assumed to be built into the history of actual customer demand. Projected incremental energy efficiency savings, reflecting measures installed during and after April 2019, are tallied and deducted from the Customer Segment demand forecasts. The resulting forecasts after reduction for energy efficiency savings are referred to as "Net Demand".

a) Residential Customer Segment Forecast – New Hampshire Division

Residential 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 customers, total population was statistically significant. In the final regression equation that was selected to predict Residential 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-19 below summarizes the Residential customer model results for customer growth, use per customer, and Residential demand for the forecast period as compared to the historical reference period.

Table IV-19: Residential Customer Segment Forecast – New Hampshire Division

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2014/15	24,392	731	17,832,949
2015/16	24,922	702	17,497,747
2016/17	25,470	717	18,272,475
2017/18	26,148	721	18,842,386
2018/19	26,827	725	19,460,887
CAGR	2.4%	-0.2%	2.2%
Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2019/20	27,454	719	19,734,859
2020/21	28,104	719	20,201,285
2021/22	28,757	719	20,670,900
2022/23	29,415	719	21,143,563
2023/24	30,077	719	21,618,995
CAGR	2.3%	0.0%	2.3%

Over the forecast period, the number of New Hampshire Residential customers is expected to grow at a rate of 2.3% annually which is consistent with the 2.4% growth rate observed over the historical reference period. Use per customer for the Residential Customer Segment is expected to remain flat over the forecast period, which again is consistent with the growth rate observed over the historical reference period. The Residential demand forecast was calculated by multiplying the forecasted number of Residential customers each month by the forecasted Residential use per customer for that month. Over the forecast period, Residential demand is expected to increase at a rate of 2.3 percent annually, consistent with the growth over the historical reference period.

b) Residential Energy Efficiency Savings – New Hampshire Division

As was done in the Customer Segment forecasts for the Maine Division, the demand forecasts are reduced by expected incremental energy savings associated with energy efficiency program targets. The estimated incremental energy savings for Residential Customers in the New Hampshire Division over the forecast period are listed in the tables below. Historical energy efficiency savings are assumed to already be reflected in metered consumption. Although previously installed efficiency measures will continue to achieve savings, those savings are already embedded in historical usage. Since the historical data used for the demand forecast extends through March 2019, incremental efficiency savings are those associated with measures expected to be installed beginning in April 2019. In determining the pattern and level of efficiency savings, Northern assumed that savings targets are met, that measures are installed ratably over twelve months each year, and that realized savings vary with customer demand patterns. For example, realized savings are expected to be very low in July and August when customer consumption is low and at their highest in January and February when customers use the most natural gas.

Table IV-20 below provides the annual energy efficiency savings targets for Residential EE programs operated by the Company, as reflected in the most recent Triennial Plan, which covers the years of 2018-2020. Northern assumed that target savings would be achieved and that savings would continue throughout the planning period at the level of the last year projected (2020).

Table IV-20: Residential Energy Efficiency Savings – New Hampshire Division (Annual MMBtu)

	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024
Home Energy Assistance (Low Inc)	1,947	2,055	2,055	2,055	2,055	2,055
Home Performance w/Energy Star	1,655	1,547	1,547	1,547	1,547	1,547
Energy Star Homes	1,441	1,486	1,486	1,486	1,486	1,486
Energy Star Products	4,032	4,351	4,351	4,351	4,351	4,351
Home Energy Reports / Behavior	3,252	2,110	2,110	2,110	2,110	2,110
Residential Total	12,328	11,550	11,550	11,550	11,550	11,550

Table IV-21 demonstrates the conversion of annual energy efficiency savings targets into monthly savings that correlate with Residential customer consumption through the first gas year, which runs from November 2019 through October 2020. The calculation shown in Table IV-21 is carried forward throughout the forecast period. Target savings are shown in Therms (Th), so the values shown in Table IV-20 were multiplied by 10, and measures are assumed to be installed ratably, so the annual savings targets are divided by 12 and listed for each month of the year. A cumulative tally of the annual savings capability installed each month is calculated then multiplied by the New Hampshire Division Residential monthly demand pattern. The demand pattern is based on a 4 year history of weather adjusted normal demand from November 2014 through October 2018. The result is the incremental efficiency savings each month. The efficiency savings for the gas year of 2019/20 tallied at the bottom of Table IV-21 tie to the Residential EE Savings shown in the table that follows.

Table IV-21: Residential Incremental EE Savings – New Hampshire Division (Th)

Month	New Installs	Cumulative Installs	Residential Demand Pattern	Incremental EE Savings
Jan 2019	10,273		18.0%	
Feb 2019	10,273		18.1%	
Mar 2019	10,273		15.2%	
Apr 2019	10,273	10,273	10.8%	1,111
May 2019	10,273	20,546	5.7%	1,179
Jun 2019	10,273	30,819	3.2%	981
Jul 2019	10,273	41,092	2.0%	836
Aug 2019	10,273	51,365	1.9%	958
Sep 2019	10,273	61,638	1.9%	1,182
Oct 2019	10,273	71,910	3.2%	2,320
Nov 2019	10,273	82,183	6.8%	5,549
Dec 2019	10,273	92,456	13.1%	12,112
Jan 2020	9,625	102,081	18.0%	18,410
Feb 2020	9,625	111,706	18.1%	20,211
Mar 2020	9,625	121,331	15.2%	18,494
Apr 2020	9,625	130,955	10.8%	14,160
May 2020	9,625	140,580	5.7%	8,068
Jun 2020	9,625	150,205	3.2%	4,780
Jul 2020	9,625	159,830	2.0%	3,252
Aug 2020	9,625	169,454	1.9%	3,159
Sep 2020	9,625	179,079	1.9%	3,433
Oct 2020	9,625	188,704	3.2%	6,089
Gas Year 2019/20				117,718

c) Residential Customer Segment Net Demand – New Hampshire Division

Residential Net Demand for the New Hampshire Division is summarized in Table IV-22 below as Residential customer segment demand less expected residential energy efficiency savings. Residential Net Demand is projected to increase by 1.8% annually over the planning period. As highlighted above, the primary drivers of residential demand growth are weather and customer growth.

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

Gas Year	Residential Demand	Residential EE Savings	Residential Net Demand
2019/20	19,734,859	-117,718	19,617,141
2020/21	20,201,285	-233,259	19,968,026
2021/22	20,670,900	-348,756	20,322,144
2022/23	21,143,563	-464,253	20,679,311
2023/24	21,618,995	-579,750	21,039,245
CAGR	2.3%	49.0%	1.8%

d) C&I Low Load Factor Customer Segment Forecast – New Hampshire Division

The C&I LLF Customer Segment is the New Hampshire Division's second largest Customer Segment in terms of demand and comprises about five times as many customers as the C&I HLF Customer Segment. In the final regression equation selected to predict C&I LLF customers, total population was statistically significant. In the final regression equation used to predict C&I LLF 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-23 below summarizes the C&I LLF customer model results for customer growth, use per customer, and C&I LLF demand for the forecast period as compared to the historical reference period.

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

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2014/15	5,551	5,241	29,089,600
2015/16	5,644	5,148	29,053,965
2016/17	5,676	5,310	30,136,119
2017/18	5,747	5,485	31,518,922
2018/19	5,786	5,428	31,404,840
CAGR	1.0%	0.9%	1.9%
Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2019/20	5,846	5,509	32,208,318
2020/21	5,891	5,550	32,696,497
2021/22	5,935	5,591	33,182,211
2022/23	5,978	5,632	33,665,188
2023/24	6,019	5,672	34,143,261
CAGR	0.7%	0.7%	1.5%

Over the forecast period, the number of New Hampshire C&I LLF customers is projected to increase by 0.7% annually compared to the 1.0% annual growth rate over the historical reference period. Use per customer for the C&I LLF Customer Segment is expected to grow by 0.7% annually which is comparable to the 0.9% growth rate over the historical reference period. The C&I LLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I LLF customers each month by the forecasted C&I LLF use per customer for that month. Over the forecast period, C&I LLF demand is expected to increase by 1.5% annually, driven primarily by continued customer growth, resulting in a moderate decline in demand growth relative to the historical reference period.

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

The New Hampshire C&I HLF Customer Segment has about one fifth as many customers as the C&I LLF segment, but is the largest Customer Segment in terms of demand. In the final regression equation that was selected to predict C&I HLF customers, a trend variable was statistically significant. In the final regression equation that was used to predict C&I HLF 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-24 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-24: C&I HLF Customer Segment Forecast – New Hampshire Division

Gas Year	Average Customers Historical	Use Per Customer (Th/Customer)	Demand (Th) Normal Historical
2014/15	1,130	30,104	34,004,973
2015/16	1,104	31,616	34,917,396
2016/17	1,102	30,897	34,043,209
2017/18	1,095	31,815	34,850,781
2018/19	1,153	32,220	37,142,089
CAGR	0.5%	1.7%	2.2%
Gas Year	Average Customers Forecast	Use Per Customer (Th/Customer)	Demand (Th) Normal Forecast
2019/20	1,167	32,479	37,893,955
2020/21	1,177	32,824	38,641,963
2021/22	1,188	33,169	39,397,338
2022/23	1,198	33,513	40,159,993
2023/24	1,209	33,858	40,929,913
CAGR	0.9%	1.0%	1.9%

Over the forecast period, the number of New Hampshire C&I HLF customers is projected to increase slightly by 0.9% annually compared to an annual growth rate of 0.5% over the historical reference period. Use per customer for the C&I HLF Customer Segment is expected to grow by 1.0% annually over the forecast period compared to 1.7% over this historical reference period. The C&I HLF Customer Segment demand forecast was calculated by multiplying the forecasted number of C&I HLF customers each month by the forecasted C&I HLF use per customer for that month. Over the forecast period, C&I HLF customer demand is expected to increase by about 1.9 percent annually, which is effectively the same as the 2.2% annual growth over the historical reference period.

f) C&I Energy Efficiency Savings – New Hampshire Division

Table IV-25 below provides the annual energy efficiency savings targets for C&I programs operated by the Company, as reflected in the 2018-2020 Triennial Plan. Northern assumed that target savings would be achieved and that savings would continue throughout the planning period at the level of the last year projected (2020).

Table IV-25: C&I Energy Efficiency Savings – New Hampshire Division (Annual MMBtu)

	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024
Large Business Energy Solutions	16,150	19,311	19,311	19,311	19,311	19,311
Small Business Energy Solutions	8,229	9,383	9,383	9,383	9,383	9,383
C&I Total	24,379	28,694	28,694	28,694	28,694	28,694

Table IV-26 provides a similar conversion of year energy efficiency savings targets to monthly savings for C&I customers to the conversion provided in Table IV-21 for Residential customers. Again, target savings are shown in Therms (Th), so the values shown in Table IV-25 were multiplied by 10, and measures are assumed to be installed ratably, so the annual savings targets are divided by 12. A cumulative tally of the annual savings capability installed each month is calculated then multiplied by the C&I monthly demand pattern to yield the incremental efficiency savings each month. The efficiency savings for the gas year of 2019/20 tallied at the bottom of Table IV-26 tie to the C&I EE Savings shown in the table that follows.

Table IV-26: C&I Incremental EE Savings – New Hampshire Division (Th)

Month	New Installs	Cumulative Installs	C&I Demand Pattern	Incremental EE Savings
Jan 2019	20,316		13.4%	
Feb 2019	20,316		13.0%	
Mar 2019	20,316		12.1%	
Apr 2019	20,316	20,316	9.3%	1,891
May 2019	20,316	40,632	6.8%	2,759
Jun 2019	20,316	60,949	5.3%	3,245
Jul 2019	20,316	81,265	5.0%	4,103
Aug 2019	20,316	101,581	5.0%	5,092
Sep 2019	20,316	121,897	5.1%	6,217
Oct 2019	20,316	142,213	6.4%	9,133
Nov 2019	20,316	162,530	7.9%	12,803
Dec 2019	20,316	182,846	10.7%	19,621
Jan 2020	23,911	206,757	13.4%	27,618
Feb 2020	23,911	230,669	13.0%	29,911
Mar 2020	23,911	254,580	12.1%	30,706
Apr 2020	23,911	278,491	9.3%	25,918
May 2020	23,911	302,403	6.8%	20,535
Jun 2020	23,911	326,314	5.3%	17,375
Jul 2020	23,911	350,226	5.0%	17,683
Aug 2020	23,911	374,137	5.0%	18,754
Sep 2020	23,911	398,048	5.1%	20,302
Oct 2020	23,911	421,960	6.4%	27,098
Gas Year 2019/20				268,323

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

C&I Total Net Demand for the New Hampshire Division is summarized in Table IV-27 below as the sum of the C&I LLF customer segment demand and the C&I HLF customer segment demand less expected C&I Total energy efficiency savings. C&I Total Net Demand is projected to increase by 1.3% annually over the forecast period.

Table IV-27: C&I Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	C&I LLF Demand	C&I HLF Demand	C&I Total EE Savings	C&I Total Net Demand
2019/20	32,208,318	37,893,955	-268,323	69,833,950
2020/21	32,696,497	38,641,963	-554,977	70,783,482
2021/22	33,182,211	39,397,338	-841,914	71,737,634
2022/23	33,665,188	40,159,993	-1,128,851	72,696,330
2023/24	34,143,261	40,929,913	-1,415,788	73,657,386
CAGR	1.5%	1.9%	51.6%	1.3%

h) Customer Segment Net Demand Forecast – New Hampshire Division

The end result of the New Hampshire Division customer segment modeling is presented below in Table IV-28, where the demand determined by customer segment, assuming normal weather and reduced for energy efficiency savings is tallied for the entire Division.

Table IV-28: Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	Residential Normal Net Demand	C&I Normal Net Demand	Division Normal Net Demand
2019/20	19,617,141	69,833,950	89,451,091
2020/21	19,968,026	70,783,482	90,751,508
2021/22	20,322,144	71,737,634	92,059,778
2022/23	20,679,311	72,696,330	93,375,641
2023/24	21,039,245	73,657,386	94,696,631
CAGR	1.8%	1.3%	1.4%

D. Normal Year Throughput Forecast

Normal Year Throughput represents the total gas required to be delivered to the Company's system in a given year to provide service to all customers under normal weather conditions. The Normal Year Throughput forecasts are developed by adjusting the Customer Segment Model net demand forecasts to reflect calendar months and then adding Company Use and Lost and Unaccounted for Gas.

1. Company Use

Company Use includes natural gas used to heat Company buildings, to run the Lewiston LNG plant, and to pre-heat gas[64]. In the regression equations that were selected to predict Company Use for the Maine and New Hampshire Divisions, Bill Cycle EDD and monthly dummy variables 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-29 below. For convenience, both normal year and design year Company Use are listed below. Design year Company Use will be utilized in Section V, Planning Load Forecast.

Table IV-29: Northern Company Use - Normal Year, Design Year (Dth)

	Normal Year			Design Year		
Gas Year	Maine Division	NH Division	Total Company	Maine Division	NH Division	Total Company
2019/20	10,012	1,887	11,899	11,130	2,016	13,146
2020/21	10,012	1,887	11,899	11,130	2,016	13,146
2021/22	10,012	1,887	11,899	11,130	2,016	13,146
2022/23	10,012	1,887	11,899	11,130	2,016	13,146
2023/24	10,012	1,887	11,899	11,130	2,016	13,146
CAGR	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

2. Lost and Unaccounted for Gas

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, the Customer Segment and Company Use forecasts were adjusted for lost and unaccounted for gas. 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"), from June 2014 through May 2018, was compiled to develop forecasts of percentage lost and unaccounted for gas sales by Division. Table IV-30 below shows the lost and unaccounted for sales percentage calculations for the Maine Division, and Table IV-31 below shows the lost and unaccounted for sales percentage calculations for the New Hampshire Division. The tables also show the Company Gas Allowance, which is the sum of Company Use and Lost and Unaccounted for Gas. Retail marketers serving Transportation Service customers are required to deliver gas to the Company's gate stations to meet their customers' metered usage grossed up by the Company Gas Allowance. The Company Gas Allowance will come into play in Section V, Planning Load Forecast.

64 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-30: Lost and Unaccounted For Sales (Dth) – Maine Division

Period	Total System Throughput	Total Retail Billed Sales	Company Use	Lost and Unaccounted For	Company Gas Allowance
6/14-5/15	10,717,095	10,478,132	9,287	229,677	238,963
6/15-5/16	9,872,198	9,635,209	8,405	228,584	236,989
6/16-5/17	10,422,296	10,131,586	8,822	281,889	290,710
6/17-5/18	10,773,384	10,632,504	10,648	130,232	140,880
Period	41,784,973	40,877,430	37,161	870,381	907,543
Percent			0.09%	2.08%	2.17%

Table IV-31: Lost and Unaccounted For Sales (Dth) – New Hampshire Division

Period	Total System Throughput	Total Retail Billed Sales	Company Use	Lost and Unaccounted For	Company Gas Allowance
6/14-5/15	8,480,896	8,364,399	2,316	114,180	116,497
6/15-5/16	7,867,945	7,744,368	1,988	121,589	123,577
6/16-5/17	8,173,451	8,002,990	1,505	168,956	170,461
6/17-5/18	8,562,780	8,484,260	1,746	76,775	78,521
Period	33,085,072	32,596,016	7,555	481,500	489,056
Percent			0.02%	1.46%	1.48%

3. Normal Year Throughput Forecasts

As indicated in Table IV-1, throughput is measured on a calendar basis and reported in Dth. Calculation of the Normal Year Throughput forecast starts by first adjusting the net demand forecast as developed using the Customer Segment models, which utilize normal billing cycle monthly weather data, to reflect calendar months. Calendarization factors were developed using the average relationship between monthly billed sales and monthly calendar throughput over the 48-month period of June 2014 through May 2018. The Calendarization process does not increase or decrease the demand forecast, but rather restates the monthly pattern of demand. Since the Customer Segment Models are developed in therms (Th), the unit used for retail billing, and throughput is expressed in dekatherms (Dth), the adjusted net demand is divided by 10.[65] Finally, Company Use and Lost and Unaccounted for Gas are added to yield normal throughput. Again, Normal Year Throughput represents the total gas required to be delivered to the Company's system in a given year to provide service to all customers under normal weather conditions.

[65] 1 dekatherm is equal to 10 therms or 1 MMBtu.

Table IV-32 and Table IV-33 below present the Normal Year Throughput forecasts for the Maine Division and New Hampshire Division, respectively. Normal Year Throughput for the Maine Division is projected to grow by about 1.6 percent annually over the forecast period. Normal Year Throughput for the New Hampshire Division is projected to grow by 1.4 percent annually over the forecast period.

Table IV-32: Normal Year Throughput (Dth) – Maine Division

Gas Year	Division Net Demand (Th)	Division Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Normal Year Throughput
2019/20	112,794,065	11,309,393	10,012	235,575	11,554,979
2020/21	114,497,001	11,481,068	10,012	239,151	11,730,231
2021/22	116,413,011	11,673,297	10,012	243,155	11,926,464
2022/23	118,246,869	11,857,572	10,012	246,993	12,114,577
2023/24	120,143,381	12,048,160	10,012	250,963	12,309,135
CAGR	1.6%	1.6%	0.0%	1.6%	1.6%

Table IV-33: Normal Year Throughput (Dth) – New Hampshire Division

Gas Year	Division Net Demand (Th)	Division Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Normal Year Throughput
2019/20	89,451,091	8,973,643	1,887	130,597	9,106,127
2020/21	90,751,508	9,104,085	1,887	132,495	9,238,468
2021/22	92,059,778	9,235,302	1,887	134,405	9,371,594
2022/23	93,375,641	9,367,282	1,887	136,326	9,505,494
2023/24	94,696,631	9,499,780	1,887	138,254	9,639,921
CAGR	1.4%	1.4%	0.0%	1.4%	1.4%

E. Energy Efficiency Impact on Demand Forecast

Incremental energy efficiency savings expected over the planning period are documented for Residential customers and C&I customers in the Customer Segment Model section for each Division. To show the impact of energy efficiency savings on the Normal Year Throughput forecasts, tables were built to hypothetically "add back" the projected Energy Efficiency savings over the planning period. In addition to the energy savings at the customer's location, energy efficiency also avoids lost and unaccounted for gas associated with the avoided consumption, since the Company would not need to receive gas at its city gates and deliver that gas to customer locations.

As Table IV-34 shows, in the absence of energy efficiency efforts, the Normal Year Throughput forecast in Maine would be higher by approximately 120,000 Dth in 2023/24, the final year of the planning horizon, and the growth rate over the period would be 1.8% rather than the expected 1.6%. In total, Normal Year Throughput in Maine is expected to be lower by 365,000 Dth over the planning period due to energy efficiency savings. Similarly, Table IV-35 shows that in New Hampshire in the absence of the expected efficiency savings the Normal Year Throughput forecast in 2023/24, the final year of the planning horizon, would be higher by approximately 200,000 Dth, and the growth rate over the planning period would have been 1.9% rather than the expected 1.4%. Normal Year Throughput in New Hampshire is expected to be lower by 600,000 Dth over the planning period due to energy efficiency savings.

Table IV-34: Energy Efficiency Impact on Normal Year Throughput (Dth) – Maine Division

Gas Year	Normal Year Throughput	Residential EE Savings	C&I EE Savings	Avoided Lost & Unaccted For	Total EE Savings	Normal Year Tput w/out EE Savings
2019/20	11,554,979	-4,621	-22,785	-571	-27,977	11,582,956
2020/21	11,730,231	-9,302	-40,273	-1,033	-50,608	11,780,838
2021/22	11,926,464	-13,916	-57,761	-1,493	-73,169	11,999,633
2022/23	12,114,577	-18,505	-75,248	-1,953	-95,706	12,210,283
2023/24	12,309,135	-23,094	-92,736	-2,413	-118,242	12,427,377
CAGR	1.6%	49.5%	42.0%	43.4%	43.4%	1.8%
PERIOD					-365,702	

Table IV-35: Energy Efficiency Impact on Normal Year Throughput (Dth) – New Hampshire Division

Gas Year	Normal Year Throughput	Residential EE Savings	C&I EE Savings	Avoided Lost & Unaccted For	Total EE Savings	Normal Year Tput w/out EE Savings
2019/20	9,106,127	-11,772	-26,832	-562	-39,166	9,145,293
2020/21	9,238,468	-23,326	-55,498	-1,147	-79,971	9,318,438
2021/22	9,371,594	-34,876	-84,191	-1,733	-120,800	9,492,394
2022/23	9,505,494	-46,425	-112,885	-2,319	-161,629	9,667,123
2023/24	9,639,921	-57,975	-141,579	-2,904	-202,458	9,842,379
CAGR	1.4%	49.0%	51.6%	50.8%	50.8%	1.9%
PERIOD					-604,023	

Taken together, as shown in Table IV-36, Company-wide expected energy efficiency savings are expected to reduce normal weather throughput requirements by nearly 1.0 Bcf over the 5-year planning horizon. Approximately three-quarters of expected savings are from the C&I sector.

Table IV-36: Energy Efficiency Impact on Normal Year Throughput (Dth) – Northern Utilities

Gas Year	Normal Year Throughput	Residential EE Savings	C&I EE Savings	Avoided Lost & Unaccted For	Total EE Savings	Normal Year Tput w/out EE Savings
2019/20	20,661,106	-16,393	-49,618	-1,133	-67,143	20,728,249
2020/21	20,968,698	-32,628	-95,771	-2,180	-130,578	21,099,277
2021/22	21,298,057	-48,791	-141,952	-3,226	-193,969	21,492,026
2022/23	21,620,071	-64,930	-188,133	-4,271	-257,335	21,877,406
2023/24	21,949,056	-81,069	-234,315	-5,317	-320,700	22,269,756
CAGR	1.5%	49.1%	47.4%	47.2%	47.8%	1.8%
PERIOD					-969,726	

V. Planning Load Forecast

Key Takeaways

Key takeaways in this chapter include the following:

- *Northern's use of a 30 year weather history is comparable to peer natural gas LDCs; Northern used a 1-in-30 year design planning standard for both design year and design day, which is on the low side (less extreme criteria) relative to peer natural gas LDCs.*
- *Changes to the Northern's Retail Choice tariffs have resulted in significant consistency in both the Maine and New Hampshire Divisions and critically, have stabilized the Company's Planning Load obligations.*
- *Northern's Planning Load is projected to grow at a rate of 1.5% over the 5-year planning period, with Design Day Planning Load approaching nearly 150,000 Dth at the end of the period (2023/24), and Design Year Planning Load approximately 23 Bcf.*

A. Introduction

Section V presents Northern's Planning Load forecasts. 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. Conceptually, although the numbers are the same, demand is viewed primarily from the perspective of understanding customer usage while load is viewed from the perspective of understanding supply requirements that must be served to meet customer demand. The demand forecast is adjusted in two fundamental ways in order to establish the Planning Load forecast. First, design standard weather conditions are established and then applied to the demand forecasts to establish design condition forecasts. Second, the projected loads of Capacity Exempt customers are removed, leaving the loads of customers for whom the Company plans.

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

Table V-1: Planning Load and Capacity Assignment Terminology

Term	Definition
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 30 year (1:30) likelihood of occurrence.
Design Throughput	Estimated Throughtput under Design weather conditions for Design Year and Design Day
Cold Snap	The coldest weather expected during a 10-day period. The Design Year forecast includes a Design Cold Snap and a Design Day
Sales Service Load	Load of Sales Service customers which the Company supplies directly
Capacity Assigned Load	Load of Transportation customers who are subject to Capacity Assignment under the Delivery Service Terms and Conditions
Capacity Exempt Load	Load of certain Transportation customers who are not subject to Capacity Assignment under the Delivery Service Terms and Conditions
Planning Load (PL)	Throughput associated with Capacity Assigned Load and Sales Service Load. Equals Total Throughput less Capacity Exempt Load demand grossed up for Company Gas Allowance, which adjusts for measurement at the gate station.

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). The Company pursues Energy Efficiency in order to reduce supply requirements. Supply 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 are also be purchased at inlets to the Company's system, although as detailed in the Regional Market Overview portion of Section III, such supplies are subject to erratic pricing and uncertain availability. The Company does not plan for customers, who have availed themselves of provisions of the Company's Delivery Service Tariffs that allow for capacity exempt status.

The Planning Load forecast reflects the gas usage of those customers to whom Northern expects to provide supply or assign capacity under design weather conditions. Planning Load forecasts were created for Design Year and Design Day conditions for both the Maine Division and the New Hampshire Division.[66] Planning Load is the measure Northern uses to assess the adequacy of its long-term resource portfolio.

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

[66] Planning Load forecasts under Normal conditions were also prepared, but are not presented.

Part B, Planning Standards and Design Weather, reviews Northern's design condition planning standards, including a survey of regional LDCs, and presents the normal and design weather assumptions used in the forecasting process;

Part C, 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 D, 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;

Part E, Overview of Capacity Assignment, summarizes the capacity assignment rules in Northern's Delivery Service Tariffs and their impact on planning in order to provide context for the Planning Load calculations;

Part F, Planning Load Forecasts, presents the Planning Load requirements under design conditions.

B. Planning Standards and Design Weather

Northern needs to be prepared to provide supply to customers during extremely cold weather conditions. In projecting customer requirements under extreme weather conditions, the Company applies its design planning standards. Design standards define how extreme are the weather conditions under which the Company plans its resources to meet. The development of design condition forecasts begins with establishing design planning criteria or standards. Northern developed this Integrated Resource Plan using a design standard of 1-in-30 years. That is, Northern's design forecasts are meant to establish supply requirements sufficient to meet the coldest conditions expected to occur during a 30 year period.[67]

Given the trend of temperature warming reviewed in the Climate Change portion in the Customer Segment Forecasts portion of the Demand Forecast Section, the length of the historical period of weather data used to calculate design condition weather can impact the design forecasts. As discussed in the Climate Change subsection, Northern chose to use a 30 year history of weather data in establishing its normal and design weather data, covering the gas years of 1988/89 through 2017/18. The 30 year period was determined to reasonably balance concerns over the warming trend by not relying on weather observations taken very long ago when temperatures were generally colder with

67 In the Company's two prior IRPs, a 1-in-33 year standard was used. The impact between 1-in-33 and 1-in30 is small, and the change allows the Company to maintain a common standard with its affiliate Fitchburg Gas and Electric Light Company.

concerns of maintaining a long enough history to allow for sufficient variation in weather that reflects conditions the Company may face.[68]

In order to assess whether Northern's weather history and planning standards are comparable to other gas LDCs in the region, Northern reviewed recent Integrated Resource Plans / Forecast and Supply Plans submitted by other LDCs in Massachusetts and New Hampshire.[69] In terms of weather history, the periods relied upon for planning range from 20 years to 50 years, and the average period, excluding Northern's affiliate Fitchburg, is 29.7 years. Thus, Northern's use of a 30 year history is comparable to other gas LDCs in the region. Design standards of neighboring LDCs range from 1-in-30 years to 1-in-44 years for design year and from 1-in-30 years to 1-in-50-years for design day. Thus, Northern's use of the 1-in-30 year standard is comparable to other LDCs in the region while also less likely to overstate the need for design condition resources.

Table V-2: Weather Data History and Design Planning Standards in recent IRP Forecasts

Gas LDC	Docket	Filing Date	Weather History	Design Year Standard	Design Day Standard
Bay State Gas Company	DPU 17-166	Oct 30, 2017	50 Years	1:33	1:33
Berkshire Gas Company	DPU 18-107	Nov 20, 2018	20 Years	1:30	1:30
Blackstone Gas	DPU 18-154	Nov 15, 2018	40 Years	1:30	1:30
Eversource (Nstar)	DPU 18-47	May 2, 2018	20 Years	1:33	1:50
Liberty Utilities (Energy North)	DG 17-152	Oct 2, 2017	38 Years	1:44	1:44
Liberty Utilities (NE Gas)	DPU 18-68	Jul 9, 2018	20 Years	1:35	1:35
National Grid (Boston Gas)	DPU 18-148	Nov 1, 2018	20 Years	1:34.5	1:44.5
Fitchburg Gas and Electric	DPU 19-02	Jan 14, 2019	30 Years	1:30	1:30
Northern Utilities	2011-00526, DG 11-290	Dec 30, 2011	20 Years	1:33	1:33
Northern Utilities	2015-00018, DG 15-033	Jan 16, 2015	30 Years	1:33	1:33
Northern Utilities	TBD	Jul 2019	30 Years	1:30	1:30

68 The 2011 IRP Settlement stipulated the use of a 30 year historical weather period, but the settlement does not apply beyond Northern's 2015 IRP.

69 No LDCs in Maine other than Northern submit IRPs.

C. 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 design planning standards of 1-in-30 year probably of occurrence for both design year and design day. The Design Year Throughput forecast was developed to determine the total load on the system that needs to be served during an extremely cold year. To estimate forecast throughput under design weather conditions, the Customer Segment Models 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 PWM, located at the Portland International Jetport) and for the New Hampshire Division (measured at the Portsmouth, New Hampshire weather station PSM, located at Pease International Tradeport). The Normal Year EDD was determined to be 7,448 EDD for Maine and 6,955 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, 1988 to October 31, 2018, the most recent 30 gas years of weather data available. The 30 year monthly averages, seasonal and total annual EDD for both Divisions are shown in Table V-3 below.

Table V-3: Normal Year and Design Year Billing Cycle Monthly EDD

	Maine Division		New Hampshire Division	
Month	Normal Year	Design Year	Normal Year	Design Year
Nov	652	732	603	684
Dec	998	1,121	948	1,076
Jan	1,291	1,450	1,235	1,401
Feb	1,315	1,477	1,258	1,427
Mar	1,125	1,264	1,073	1,217
Apr	867	867	809	809
May	522	522	460	460
Jun	234	234	194	194
Jul	45	45	33	33
Aug	13	13	9	9
Sep	69	69	55	55
Oct	317	317	278	278
Winter	5,381	6,044	5,117	5,806
Summer	2,067	2,067	1,838	1,838
Total	7,448	8,111	6,955	7,644

The Design Year EDD represents extreme winter conditions with a statistically defined probability of occurring on a very infrequent basis (once in 30 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 EDD was determined to be 8,111 EDD for Maine and 7,644 EDD for New Hampshire. The Company's Design Year EDD reflects design conditions of 1-in-30 year frequency of occurrence during the winter period (November through March) and normal weather for the summer months (April through October). The statistical probability associated with the design standard was applied to the winter period EDD. Design winter EDD were calculated by first summing the billing cycle EDD for each winter from 1988/89 through 2017/18 (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-30 year probability of occurrence. The design winter EDD were then allocated to the winter months based by multiplying the normal EDD for each winter month by adjustment factor equal to the design winter EDD divided by normal winter EDD. The Design Year monthly, seasonal and total annual EDD for both Divisions are shown above in Table V-2.

To determine the throughput associated with Design Year weather in each Division, the Company re-ran the Customer Segment and Company Use models containing EDD independent variables (i.e., Residential use per customer, C&I LLF use per customer, C&I HLF use per customer, and Company Use) using the 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 net customer segment demand. Note that design condition energy efficiency savings are expected to be higher than normal condition energy efficiency savings.

The Maine Division customer segment net demand forecasts under design conditions are provided below in Table V-4 for Residential customers, Table V-5 for C&I customers and Table V-6 for the combined Maine Division customer segment net demand.

Table V-4: Design Residential Customer Segment Net Demand (Th) - Maine Division

Gas Year	Residential Demand	Residential EE Savings	Residential Net Demand
2019/20	18,857,597	-49,223	18,808,374
2020/21	19,249,162	-99,418	19,149,744
2021/22	19,644,563	-148,845	19,495,718
2022/23	20,043,797	-197,959	19,845,839
2023/24	20,447,233	-247,030	20,200,203
CAGR	2.0%	49.7%	1.8%

Table V-5: Design C&I Customer Segment Net Demand (Th) - Maine Division

Gas Year	C&I LLF Demand	C&I HLF Demand	C&I Total EE Savings	C&I Total Net Demand
2019/20	71,248,193	28,786,686	-237,285	99,797,594
2020/21	72,677,131	28,948,499	-420,397	101,205,232
2021/22	74,121,416	29,303,677	-603,372	102,821,722
2022/23	75,580,927	29,557,532	-786,282	104,352,177
2023/24	77,056,056	29,854,406	-969,063	105,941,399
CAGR	2.0%	0.9%	42.2%	1.5%

Table V-6: Design Customer Segment Net Demand (Th) - Maine Division

Gas Year	Residential Design Net Demand	C&I Design Net Demand	Division Design Net Demand
2019/20	18,808,374	99,797,594	118,605,968
2020/21	19,149,744	101,205,232	120,354,976
2021/22	19,495,718	102,821,722	122,317,440
2022/23	19,845,839	104,352,177	124,198,016
2023/24	20,200,203	105,941,399	126,141,602
CAGR	1.8%	1.5%	1.6%

To produce the Design Year Throughput forecast, the design customer segment net demand was calendarized, converted to Dth, and design Company Use and lost and unaccounted for gas was added, similar to the process used to develop the Normal Year Throughput forecast. The Maine Division Design Year Throughput forecast is provided in Table V-7.

Table V-7: Design Year Throughput (Dth) – Maine Division

Gas Year	Division Net Demand (Th)	Division Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Design Year Throughput
2019/20	118,605,968	11,905,654	11,130	246,877	12,163,660
2020/21	120,354,976	12,082,054	11,130	250,551	12,343,735
2021/22	122,317,440	12,279,048	11,130	254,655	12,544,832
2022/23	124,198,016	12,468,115	11,130	258,593	12,737,838
2023/24	126,141,602	12,663,532	11,130	262,663	12,937,325
CAGR	1.6%	1.6%	0.0%	1.6%	1.6%

The customer segment net demand forecasts under design conditions for the New Hampshire Division are provided below in Table V-8 for Residential customers, Table V-9 for C&I customers and Table V-10 for the combined New Hampshire Division customer segment net demand.

Table IV-8: Design Residential Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	Residential Demand	Residential EE Savings	Residential Net Demand
2019/20	21,395,076	-126,542	21,268,534
2020/21	21,900,757	-251,756	21,649,001
2021/22	22,409,896	-376,922	22,032,974
2022/23	22,922,342	-502,088	22,420,253
2023/24	23,437,792	-627,254	22,810,538
CAGR	2.3%	49.2%	1.8%

Table V-9: Design C&I Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	C&I LLF Demand	C&I HLF Demand	C&I Total EE Savings	C&I Total Net Demand
2019/20	34,781,609	38,234,034	-277,367	72,738,276
2020/21	35,289,337	38,985,161	-575,938	73,698,560
2021/22	35,794,088	39,743,657	-874,638	74,663,106
2022/23	36,295,627	40,509,433	-1,173,173	75,631,887
2023/24	36,791,645	41,282,474	-1,471,542	76,602,577
CAGR	1.4%	1.9%	51.8%	1.3%

Table V-10: Design Customer Segment Net Demand (Th) - New Hampshire Division

Gas Year	Residential Design Net Demand	C&I Design Net Demand	Division Design Net Demand
2019/20	21,268,534	72,738,276	94,006,810
2020/21	21,649,001	73,698,560	95,347,562
2021/22	22,032,974	74,663,106	96,696,080
2022/23	22,420,253	75,631,887	98,052,141
2023/24	22,810,538	76,602,577	99,413,115
CAGR	1.8%	1.3%	1.4%

To produce the Design Year Throughput forecast, the design customer segment net demand was calendarized, converted to Dth, and design Company Use and lost and unaccounted for gas was added, similar to the process used to develop the Normal Year Throughput forecast. The New Hampshire Division Design Year Throughput forecast is provided in Table V-11.

Table V-11: Design Year Throughput (Dth) – New Hampshire Division

Gas Year	Division Net Demand (Th)	Division Net Cal Demand (Dth)	Company Use	Lost and Unaccounted For	Design Year Throughput
2019/20	94,006,810	9,443,051	2,016	137,299	9,582,366
2020/21	95,347,562	9,577,648	2,016	139,258	9,718,923
2021/22	96,696,080	9,713,011	2,016	141,228	9,856,255
2022/23	98,052,141	9,849,132	2,016	143,209	9,994,357
2023/24	99,413,115	9,985,751	2,016	145,197	10,132,964
CAGR	1.4%	1.4%	0.0%	1.4%	1.4%

Lastly, since Northern is a single company that manages a single portfolio, the throughput forecast for the two divisions are summed to yield the Company level Design Year Throughput, as shown in Table V-12.

Table V-12: Design Year Throughput (Dth) – Northern Utilities

Gas Year	Company Net Demand (Th)	Company Net Demand (Dth)	Company Use	Lost and Unaccounted For	Design Year Throughput
2019/20	212,612,778	21,348,704	13,146	384,176	21,746,026
2020/21	215,702,538	21,659,703	13,146	389,809	22,062,658
2021/22	219,013,520	21,992,059	13,146	395,882	22,401,087
2022/23	222,250,156	22,317,247	13,146	401,802	22,732,195
2023/24	225,554,717	22,649,283	13,146	407,860	23,070,290
CAGR	1.5%	1.5%	0.0%	1.5%	1.5%

Table V-13 presents the design condition version of Table IV -36 from the Demand Forecast section, which shows the impact of expected energy efficiency savings on Design Year Throughput. Approximately three-quarters of expected savings are from the C&I sector. Taken together, expected energy efficiency savings in both divisions are expected to reduce design weather throughput by more than 1.0 Bcf over the 5-year planning horizon.

Table V-13: Energy Efficiency Impact on Design Year Throughput (Dth) – Northern Utilities

Gas Year	Design Year Throughput	Residential EE Savings	C&I EE Savings	Avoided Lost & Unaccted For	Total Design EE Savings	Design Year Tput w/out EE Savings
2019/20	21,746,026	-17,577	-51,465	-1,185	-70,226	21,816,252
2020/21	22,062,658	-35,117	-99,633	-2,287	-137,038	22,199,696
2021/22	22,401,087	-52,577	-147,801	-3,388	-203,766	22,604,853
2022/23	22,732,195	-70,005	-195,945	-4,488	-270,438	23,002,634
2023/24	23,070,290	-87,428	-244,061	-5,588	-337,076	23,407,366
CAGR	1.5%	49.3%	47.6%	47.4%	48.0%	1.8%
PERIOD					-1,018,545	

D. 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 standard Peak Day EDD 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 under the design standard.

The Design Day effective degree-days using Northern's 1-in-30 year planning standard was determined to be 78.9 EDD for the Maine Division and 80.1 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 1988/89 through 2017/18 (i.e., the most recent thirty gas years, consistent with Design Year). The 30 year average and standard deviation of the Peak Days was calculated and used to calculate the Design EDD associated with a 1-in-30 year probability of occurrence. The Normal and Design standard Peak Day EDD for both Divisions are shown in Table V-14 below, along with the maximum recorded EDD in each division, the maximum daily Throughput recorded in each division and the associated EDD. In addition to Peak Day EDD, Table V-14 provides normal and design 10-Day Cold Snap EDD, the maximum recorded EDD over a 10-Day period and the maximum recorded Throughput over a 10-day period and the associated EDD.

Table V-14: Normal and Design Peak Day and 10-Day Cold Snap EDD

	Maine Division		New Hampshire Division	
	Normal EDD	Design EDD (1:30)	Normal EDD	Design EDD (1:30)
Peak Day EDD	68.8	78.9	68.7	80.1
Cold Snap EDD	541.7	648.8	524.4	642.4
	Maine Division		New Hampshire Division	
	Max Recorded[1]	Date	Max Recorded[1]	Date
Peak Day EDD	79.8	Jan 2, 2014	83.0	Jan 15, 2004
Cold Snap EDD	655.8	thru Jan 6, 2019	646.3	thru Jan 6, 2018
	Maine Division		New Hampshire Division	
	Max Throughput[2]	Date	Max Recorded[2]	Date
Peak Day TPUT	80,279	Jan 21, 2019	66,470	Jan 21, 2019
Actual EDD	67.3	Jan 21, 2019	72.4	Jan 21, 2019
Cold Snap TPUT	740,691	thru Jan 6, 2019	572,851	thru Jan 6, 2018
Cold Snap EDD	655.8	thru Jan 6, 2019	646.3	thru Jan 6, 2018

[1] *Max EDD recorded during 30 Year Weather History (1988/89 to 2017/18)*
[2] *Max Throughput recorded since 11/1/2009*

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 April 1, 2018 through March 31, 2019 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; (3) EDD calculated to reflect very cold temperatures (i.e., EDD base 15)[70]; and (4) 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, which results in Peak Day throughput for the 2018/19 winter calibrated to design standard conditions. The resulting the 2018/19 Design Day Throughput was then adjusted based on the growth in Design Year Throughput for each Division to extend the Design Day Throughput forecast throughout the planning period. This approach assumes that current load factors remain the same over the forecast period. Table V-15 presents the Design Day Throughput forecast for the Maine Division and the New Hampshire Division and the Company totals for the forecast period.

Table V-15: Design Peak Day Throughput (Dth)

Gas Year	ME Design Peak Day TPUT	ME Annual Growth Rate	NH Design Peak Day TPUT	NH Annual Growth Rate	NUI Design Peak Day TPUT
2018/19	89,461		71,966		161,427
2019/20	90,563	1.2%	73,122	1.6%	163,685
2020/21	91,903	1.5%	74,164	1.4%	166,067
2021/22	93,400	1.6%	75,212	1.4%	168,613
2022/23	94,837	1.5%	76,266	1.4%	171,104
2023/24	96,323	1.6%	77,324	1.4%	173,646
CAGR	1.5%		1.4%		1.5%

Since very cold Peak Days are rare, there are limited data for forecasting and limited observations for model assessment. As shown in Table V-14, on January 21, 2019, Northern experienced a new system record Peak Day Throughput. Weather conditions that day were much warmer than Northern's Design Day EDD. In the Maine Division, the 67 EDD recorded were lower than even Normal Peak Day EDD (69) and much lower than Design Peak Day EDD (79). In the New Hampshire Division, the 72 EDD recorded was lower than Design Peak Day EDD (80). Northern applied the actual EDD values to its design day model and calculated estimated daily throughput of 77,188 Dth for Maine and 65,099 Dth for New Hampshire, for a total daily forecast of 142,287 Dth. Actual throughput on

[70] EDD are typically calculated to 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 base 15 EDD and days that are colder than 15 degrees have EDD = 15 – average temperature (adjusted for wind).

January 21, 2019, was 80,279 Dth in the Maine Division and 66,470 Dth in the New Hampshire Division, for a daily total of 146,749 Dth. The Maine model under predicted by 3,091 Dth, or 3.8%, while the New Hampshire model under predicted by 1,371 Dth, or 2.1%. Collectively, the models were off by 3.0%. These results suggest Northern's design day throughput model is reasonably accurate, and does not show a bias towards over-predicting Design Day demand.

E. 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 impact Northern's Planning Load.

1. Capacity Assignment Rules

At the time Northern's 2015 IRP was filed, there were significant differences in the terms of the Delivery Service Tariffs in the two Divisions and certain program attributes lead to unstable Planning Load obligations, which significantly impacted the approach taken in the 2015 IRP. However, during the intervening years changes have been made to the Delivery Service Tariffs in both states that have brought the two tariffs into close alignment. Effective November 1, 2019, Capacity Assignment in the Maine Division will be based on 100 percent of a Transportation Service customer's peak day demand, which will be consistent with the approach taken in the New Hampshire Division. Since the planning horizon begins with Gas Year 2019/20, the IRP has been developed assuming 100 percent capacity assignment in the Maine Division.

The following basic Capacity Assignment provisions are or will be common to the Delivery Service Tariffs of both the Maine Division and New Hampshire Division starting November 1. 2019:

1. Any Customer who received Sales Service from the Company, who then initiates Transportation Service, is assigned capacity with a Total Capacity Quantity (TCQ) equal to 100 percent of the Customer's estimated Peak Day demand times the Capacity Ratio.
2. A Capacity Ratio, equal to the amount of capacity divided by estimated requirements of sales and capacity assigned transportation customers on the Peak Day, is used to allocate capacity on a proportionately among sales and transportation customers.

3. Each transportation customer's TCQ is reviewed annually by re-estimating their Peak Day demand and updating the Capacity Ratio. The customer's TCQ is adjusted if their updated TCQ differs from their prior TCQ by a threshold amount.[71]
4. Any Customer at a new service location who commences Transportation Service within 60 days of initiating service is not assigned capacity, and is therefore Capacity Exempt, subject to an annual usage demonstration threshold of 25,000 therms in the Maine Division.
5. Any Capacity Exempt customer who chooses to receive Sales Service will become subject to Capacity Assignment if they subsequently choose a retail supplier.
6. With the exception of off-system supply purchases, retail suppliers are assigned resources from Northern's entire capacity portfolio. The majority of assigned capacity is released directly to retail suppliers through each pipeline's Electronic Bulletin Board or comparable process for Canadian resources. A small portion of the assigned capacity is provided as a "Company-Managed" service, which is controlled by the Company.
7. Delivered Supply purchases made by Northern are solely for serving Sales Service customer load, and are not assignable to retail suppliers. Thus, apart from the assignment of limited Company-managed resources, retail suppliers directly control their own supply purchases.

2. Impact on Planning Load

The changes to the Delivery Service Terms and Conditions since Northern's 2015 IRP have been very critical to stabilizing the Company's Planning Load, which has allowed the Company to define its Planning Load obligations and commit to incremental long term capacity additions to its gas supply portfolio.

If Northern operated a system without retail access, where all customers were served by Northern, then the Planning Load Forecast would equal the Throughput Forecast. Starting in November 2019, Northern's planning obligations will be to supply Sales Service loads and to assign capacity to retail suppliers of Capacity Assigned transportation customers, based on 100 percent of their Peak Day requirements. The only customers Northern does not plan for are Capacity Exempt transportation customers. Thus, as shown in the next section, Northern calculates its Planning Load by subtracting Capacity Exempt load from total Throughput.

[71] In the Maine Division, a customer's TCQ is adjusted if their TCQ changes by more than 5 percent; in the New Hampshire Division, a customer's TCQ is adjusted if their TCQ changes by more than 10 percent.

F. Design Year and Design Day Planning Load

Planning Load is calculated by subtracting Capacity Exempt load from total Throughput. Although this section documents the Design condition Planning Load calculations, Planning Load was also calculated under Normal conditions.

1. Design Year Planning Load

In order to separately estimate Capacity Exempt Net Demand, the Company calculated Capacity Exempt Net Demand expressed as a percentage of C&I Total Net Demand for the last 12 months of the historical period. These monthly percentages were applied to the design forecast of C&I Total Net Demand in order to develop the design forecast of Capacity Exempt Transportation Demand. Table V-16 shows these calculations for the Maine Division.

Table V-16: Design Year Capacity Exempt Net Demand (Th) – Maine Division

Gas Year	C&I Total Net Demand	Capacity Exempt PCT C&I Demand	Capacity Exempt Net Demand
2019/20	99,797,594	30.5%	26,718,122
2020/21	101,205,232	30.5%	27,129,124
2021/22	102,821,722	30.5%	27,591,849
2022/23	104,352,177	30.5%	28,038,986
2023/24	105,941,399	30.5%	28,496,035
CAGR	1.5%	0.0%	1.6%

Table V-17 shows the subtraction of design Capacity Exempt Net Demand and the Company Gas Allowance required to be delivered by the retail suppliers of Capacity Exempt customers from Design Year Throughput with the result being the Design Year Planning Load for the Maine Division.

Table V-17: Design Year Planning Load (Dth) – Maine Division

Gas Year	Design Year Throughput	Capacity Exempt Net Demand	Company Gas Allowance	Design Year Planning Load
2019/20	12,163,660	2,671,812	58,030	9,433,818
2020/21	12,343,735	2,712,912	58,923	9,571,900
2021/22	12,544,832	2,759,185	59,928	9,725,720
2022/23	12,737,838	2,803,899	60,899	9,873,040
2023/24	12,937,325	2,849,603	61,892	10,025,830
CAGR	1.6%	1.6%	1.6%	1.5%

Table V-18 shows the calculation of design Capacity Exempt Net Demand for the New Hampshire Division. Notably, Capacity Exempt Net Demand in the two divisions is almost identical;

however Capacity Exempt load accounts for a greater portion of total C&I load in New Hampshire than in Maine.

Table V-18: Design Year Capacity Exempt Net Demand (Th) – New Hampshire Division

Gas Year	C&I Total Net Demand	Capacity Exempt PCT C&I Demand	Capacity Exempt Net Demand
2019/20	72,738,276	40.9%	26,788,199
2020/21	73,698,560	40.9%	27,170,766
2021/22	74,663,106	40.9%	27,555,611
2022/23	75,631,887	40.9%	27,942,651
2023/24	76,602,577	40.9%	28,331,086
CAGR	1.3%	0.0%	1.4%

Table V-19 shows the subtraction of design Capacity Exempt Net Demand and the Company Gas Allowance required to be delivered by the retail suppliers of Capacity Exempt customers from Design Year Throughput with the result being the Design Year Planning Load for the New Hampshire Division.

Table V-19: Design Year Planning Load (Dth) – New Hampshire Division

Gas Year	Design Year Throughput	Capacity Exempt Net Demand	Company Gas Allowance	Design Year Planning Load
2019/20	9,582,366	2,678,820	39,598	6,863,948
2020/21	9,718,923	2,717,077	40,163	6,961,683
2021/22	9,856,255	2,755,561	40,732	7,059,962
2022/23	9,994,357	2,794,265	41,304	7,158,788
2023/24	10,132,964	2,833,109	41,878	7,257,977
CAGR	1.4%	1.4%	1.4%	1.4%

Lastly, since Northern is a single company that manages a single portfolio, the Design Year Planning Load forecasts for the two divisions are summed to yield the Company level Design Year Planning Load, as shown in Table V-20. Recall from the presentation of Design Year EDD in the Design Year Throughput section that during the summer period, April through October, normal weather is assumed.

Table V-20: Design Year Planning Load (Dth) – Northern Utilities

Gas Year	Design Year Throughput	Capacity Exempt Net Demand	Company Gas Allowance	Design Year Planning Load
2019/20	21,746,026	5,350,632	97,628	16,297,766
2020/21	22,062,658	5,429,989	99,086	16,533,583
2021/22	22,401,087	5,514,746	100,660	16,785,682
2022/23	22,732,195	5,598,164	102,203	17,031,828
2023/24	23,070,290	5,682,712	103,770	17,283,808
CAGR	1.5%	1.5%	1.5%	1.5%

2. Design Day Planning Load

The same as with Design Year Planning Load, to establish the Design Day Planning Load forecast, Design Day Capacity Exempt customer load is subtracted from the Design Day Throughput forecast.

Design Day Planning Load models for each Division, similar to the Design Day Throughput models described earlier, were specified to estimate the Design Day Planning Load, which was then subtracted from Design Day Throughput to calculate Capacity Exempt load. The dependent variable in these Design Day Planning Load models was historical daily Planning Load for the period April 1, 2018 through March 31, 2019 by Division and the independent variables were identical to the independent variables used in the Design Day Throughput Models, including (1) days of the week; (2) winter months; (3) EDD calculated to reflect very cold temperatures (i.e., EDD base 15); and (4) the prior day's EDD. The regression models are presented in Appendix 1.

After the Design Day Planning Load models were specified for each Division, the regression equations were adjusted by replacing the EDD-based variables with Design Day EDD, which results in Peak Day Planning Load for the 2018/19 winter calibrated to design standard conditions. The resulting 2018/19 Design Day Planning Load was then subtracted from the 2018/19 Design Day Throughput to calculate Design Day Capacity Exempt load. Table V-21 presents the Design Capacity Exempt Peak Day Load forecast, which reflects both net demand and the Company Gas Allowance, for the Maine Division and the New Hampshire Division and the Company totals for the forecast period.

Table V-21: Design Capacity Exempt Peak Day Load (Dth)

Gas Year	ME Design CE Peak Day + CGA	ME Annual Growth Rate	NH Design CE Peak Day + CGA	NH Annual Growth Rate	NUI Design CE Peak Day + CGA
2018/19	12,734		9,289		22,023
2019/20	12,932	1.6%	9,460	1.8%	22,393
2020/21	13,131	1.5%	9,596	1.4%	22,727
2021/22	13,355	1.7%	9,731	1.4%	23,087
2022/23	13,571	1.6%	9,868	1.4%	23,440
2023/24	13,793	1.6%	10,005	1.4%	23,798
CAGR	1.6%		1.5%		1.6%

The Company total forecast of Design Capacity Exempt Peak Day Load was then subtracted from the Company Design Peak Day Throughput to calculate Company Design Day Planning Load, as shown in Table V-22.

Table V-22: Design Peak Day Planning Load (Dth)

Gas Year	NUI Design Peak Day Tput	NUI Design CE Peak Day + CGA	NUI Design Peak Day Planning Load
2018/19	161,427	22,023	139,404
2019/20	163,685	22,393	141,292
2020/21	166,067	22,727	143,341
2021/22	168,613	23,087	145,526
2022/23	171,104	23,440	147,664
2023/24	173,646	23,798	149,848
CAGR	1.5%	1.6%	1.5%

3. Daily Planning Load for Sendout®

Normal and Design daily Planning Load forecasts were prepared for the full planning period for analysis in the Sendout® program. The monthly forecasts described and summarized above were allocated to days according to the historical daily throughput pattern observed during the Gas Year 2013/14 (November 1, 2013 – October 31, 2014). In addition, adjustments were made to the daily distribution of monthly Planning Load during the months of January. First, a daily pattern of EDD was established for Januaries. The pattern distributed EDD such that the last day of January has Design Peak Day EDD, the last 10 days of January have Design Cold Snap EDD and the balance of daily January EDD are adjusted downward proportionately to match the design January EDD shown in Table V-14. The pattern for the 10-day Cold Snap was taken from the 10 day period ended January 6, 2018, which was both the coldest (highest EDD total) 10-day period on record in both Divisions and also the period with the highest 10 consecutive day throughput on record in both Divisions, as shown on Table V-14. The balance of the January daily pattern was from January 2014. Second, base (intercept) and space (slope) factors were calculated by regressing actual daily throughput against actual daily EDD observed in the month of January 2014. The design daily January EDD pattern was then applied and the daily throughput was calculated using the base and space factors. The resulting daily throughput pattern was used to allocate the monthly forecasts to days. Lastly, each year the calculated Design Day Planning Load was set as the daily value for January 31 each year and any residuals were allocated among the other 30 days of each January.

VI. Current Portfolio

Key Takeaways

Key takeaways in this chapter include the following:

- *Northern has identified several Resource Impact categories that help to better define the impacts associated with each resource or resource type in Northern's portfolio, including possible resource additions to be discussed in Section VIII.*
- *Current energy efficiency programs in both Maine and New Hampshire deliver cost-effective energy savings and are integrated into the Company's long-term resource plan. Energy efficiency resources have favorable Resource Impacts, reducing future Planning Load requirements, improving the environment and stimulating local economic development.*
- *Northern's current portfolio of long-term capacity resources provides a maximum daily quantity of 72,128 Dth of supply to Northern's system. Pending capacity resources, Atlantic Bridge and Portland XPress, and the currently proposed capacity resource, Westbrook XPress, will increase this volume to 99,558 Dth by November 2022. These additions will reduce, but not eliminate, Northern's reliance upon the availability of Delivered Supplies. Northern's Capacity Resources cost effective and provide resource capability that cannot be replaced with other resources.*
- *Northern solicits for Asset Management services and supplemental supplies annually in order to fill its capacity, mitigate costs to customers and minimize pipeline scheduling risk. Northern's contracting strategies for physical supply provide price risk management benefits.*

A. Introduction

Section VI provides an overview of Northern's current portfolio, including a review of current Energy Efficiency programs, an overview of the Company's current, pending and proposed long-term capacity resources, narrative descriptions of each capacity resource by path, and a brief discussion of the Company's supply procurement practices. In addition to general descriptions, available data on various Resource Impact categories are provided to provide a more thorough understanding of the pros and cons of each resource or resource category.

As supporting information, Appendix 2 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 2 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"), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point. To supplement the Appendix 2 capacity path diagrams, Appendix 3 provides a set of maps showing each capacity path from supply source to the Company's system as well as individual maps of each pipeline.

The remainder of the Current Portfolio section is organized as follows:

Part B, Resource Impact Categories, outlines the various areas explored relative to each resource or resource category for the Current Portfolio resources presented in this Section VI and the Incremental Resources presented in Section VIII;

Part C, Review of Energy Efficiency Resources, provides narrative updates and program level data, via Appendix 4, regarding the Energy Efficiency programs expected to be implemented under Efficiency Maine's latest Triennial Plan in the Maine Division and by Northern under the Three-Year EERS Plan in the New Hampshire Division, along with narrative regarding resource impacts;

Part D, Long-Term Supply Resources, summarizes the amount of long-term capacity under contract by resource type and the supply sources accessed, including contract renewal dates, how the capacity is assigned to retail marketers under the Delivery Service Terms and Conditions, and provides resource narratives that describe each path in more detail, as well as information available regarding impacts of these resources;

Lastly, Part E, Short-Term Supply and Price Risk Management, provides a summary describing how the Company uses its long-term resources to purchase supply and mitigate cost to customers from year to year.

B. Resource Impact Categories

This is Northern's first IRP to address the newer requirements set out in the New Hampshire statutes on Least Cost Integrated Resource Plan, specifically RSA 378:38 parts V, VI and VII. As such, the IRP introduces new Resource Impact categories which are used to better define the attributes of the resources in the portfolio. In order to better understand how various resources compare, the Company has attempted to compile various data and comments on all of its resources, including existing ones. Please note that Section III, Planning Environment, includes a summary of the Clean Air Act and State Energy Policies.

1. Financial Cost

Financial Cost is the most fundamental aspect in determining whether an IRP is Least Cost. Financial Cost is shown in terms of average Cost per Dth (or MMBtu) of supply delivered or avoided. For supply resources, the average cost reported is the evaluated cost based on the expected utilization of each resource as determined via a Sendout® analysis. That is, the Company's Planning Load obligations vary with weather conditions and are not the same every day, therefore all supply resources are not used fully every day. Appendix 5 reports expected utilization by supply resource as well as commodity cost, demand cost and resulting average delivered cost. In accordance with contractual requirements and to protect the Company's vendors in cases where new capacity has not yet been brought into service, and to protect the Company's leverage in future supply negotiations, the Company has sought to protect some of the Financial Cost of supply resources.

For Energy Efficiency resources, the Company has adopted the savings target and budget assumptions reflected in the triennial plans in each state and divided Total Costs of program spending and customer investments by projected Lifetime Savings to estimate average Cost per Dth (MMBtu), without time value of money discounts or other adjustments.

2. Resource Capability

Resource capability can be measured by the yearly Dth and peak day Dth deliverability of each resource. The Design Year and Design Day capability of resources is the primary focus, since the goal of the IRP is to demonstrate how Planning Load can be met under design conditions. Certain resources may be ideal from one or more perspectives (low cost, favorable environmental impact), but may also be limited in capability. In assessing Resource Capability, the Company seeks to understand how much of a resource can effectively be deployed to meet its planning obligations.

3. Deployment Timing

Deployment timing is an important consideration because some resources take longer than others to implement. Deployment timing can be taken together with Resource Capability to better understand how quickly a resource can be made available to meet Planning Load requirements. For example, while very scalable, pipeline expansion capacity can take approximately 4 years to bring into service. In the case of Energy Efficiency resources, multiple years of incremental investment are needed to build savings levels sufficiently to displace existing and forecasted service requirements.

4. Fuel Security

Fuel Security can be thought of as reliability of supply, or avoided supply requirements due to Energy Efficiency investments. Fuel Security relates to control over resources and assurances in deliverability and performance over time. Without Fuel Security, future supplies may be uncertain or unavailable. In terms of traditional supply resources, Fuel Security can be provided by contractual renewal rights, access to liquid supply points and proven success on the part of the pipeline or storage operator in properly operating and maintaining their facilities. Fuel Security from an Energy Efficiency standpoint is enhanced by training of installers, improvements in new technologies and building envelope insulation techniques and also by appropriate Evaluation, Measurement, and Verification ("EM&V") of expected efficiency savings.

5. Price Stability

Price stability is similar to Financial Cost in that it relates to the prices customers pay for supply. Significant information was provided in the Regional Market Overview part of Section III, including data on how natural gas prices for supply delivered into New England are generally higher and more volatile than prices available at other locations, such as the Dawn Hub which is a Liquidity Tier 1 supply point. Other things being equal, customers value stable and predictable energy prices. Therefore, resources that promote stable pricing have a positive impact.

6. Environmental Impact

The Company purchases and delivers natural gas to customers. Natural gas is primarily methane (CH4), which as explained in the Clean Air Act part of the Planning Environment Section, is a Greenhouse Gas ("GHG"). The Company has made extensive efforts to improve its handling of the gas we deliver to customers as have companies that operate in other segments of the natural gas supply chain. In terms of Resource Impact, the Company seeks to understand the degree to which certain gas supply resources differ from others in terms of Environmental Impact. The Company presents later in this Section VI below its initial findings with respect to its existing, pending and proposed supply resources, as well as the favorable Environmental Impact provided by Energy Efficiency. In Section VIII, the Company also discusses opportunities to add Renewable Natural Gas.

7. Economic Development and Jobs

Economic Development and Jobs impact of various resource options evaluates the degree to which investment is the resource option can stimulate local investment, tax savings and employment. Local opportunity provides benefits to customers and the communities the Company serves.

8. Health & Safety

Health and Safety impact is viewed generally as the risk of injury or illness relative to a resource option, including whether certain resource options can reduce the risk of injury or illness. Examples include safety incidences related to the construction, operation and maintenance of natural gas facilities and also the installation of Energy Efficiency measures.

C. Review of Energy Efficiency Resources

1. Maine Energy Efficiency

Given the recent passage of L.D. 1757,[72] which requires Commission deference to the EMT on matters such as avoided costs and cost effectiveness, the Company has adopted the natural gas

[72] 129th Maine Legislature, First Regular Session-2019, H.P. 1251 - L.D. 1757, An Act to Clarify Certain Standards for the Efficiency Maine Trust's Triennial Plan, May 21, 2019.

efficiency savings estimates contained in the EMT's 2020-2022 Triennial Plan as filed with the Commission. Appendix 4 provides Efficiency Maine's budget and performance metrics for the fiscal year Plans through 2022, truncated to show only natural gas programs.[73] Efficiency savings targets for fiscal year 2022 are assumed to continue each year throughout the planning period. Given that Efficiency Maine implements its programs on a statewide basis, the Company assumed that 66 percent of natural gas savings would accrue to Northern customers.

Another notable recent piece of legislation is L.D. 1766, An Act To Transform Maine's Heat Pump Market To Advance Economic Security and Climate Objectives.[74] The legislation establishes a statewide goal to install 100,000 new, high-performance, air source heat pumps in Maine to provide heating in both residential and nonresidential spaces. Among other things, the new legislation specifies that in the construction, remodeling or renovation of a multifamily residential structure funded in whole or in part by public funds, guarantees or bond proceeds, high-performance air source heat pumps may be used as the primary heating system without requiring a waiver from the Commission. The goal set forth is especially notable in Maine, where the residential home heating fuel mix is made up of approximately 61% fuel oil versus approximately 8% natural gas. The IRP forecast does not reflect any adjustments for this new legislation.

2. New Hampshire Energy Efficiency

Northern's energy efficiency programs in New Hampshire are informed by nearly two decades of experience working with stakeholders, consultants, our colleagues at the other gas and electric utilities, as well as customers. Our internal energy efficiency staff of more than a dozen planners, implementers and administrators work across jurisdictions (in Massachusetts) and are supported by a deep complement of vendors, contractors, builders and evaluation firms, all with deep knowledge of demand side efficiency and conservation.

As a result of the NH Energy Efficiency Resource Standard ("EERS") described in Section III, the Company's investment in Energy Efficiency for New Hampshire customers has grown from approximately $1.4 million in 2017 to a proposed $2.4 million in 2020, a 70 percent increase over just the past three years. The Company's existing portfolio of gas efficiency programs focuses on customers in three categories: non-low income residential customers, low income residential customers, and commercial and industrial ("C&I") customers.

The backbone of our residential offerings is the Home Performance with Energy Star® Program for non-low income customers and the Home Energy Assistance Program for those customers with

73 PROPOSED TRIENNIAL PLAN FOR FISCAL YEARS 2020–2022, Efficiency Maine Trust, Appendix B - Budget and Performance Metrics, provided in Excel format.

74 129th Maine Legislature, First Regular Session-2019, L.D. No. 1766, S.P. 597, IN Senate, May 21, 2019, An Act to Transform Maine's Heat Pump Market to Advance Economic Security and Climate Objectives, page 4.

household income under 60% of area median income ("AMI"). Both of these programs take a whole-house approach to existing homes where there is opportunity to make them more efficient in their use of heat, hot water and electricity. By contracting with home energy auditors, weatherization contractors, and, for the low income program, the Community Action Agencies in our service territory, the Company targets those homes that can cost effectively benefit from improvements to building envelope, heating and hot water system insulation, servicing and even replacement. These residential programs are designed to serve the whole home. To optimize the opportunity of having trained professionals on site, both gas saving measures and services as well as high efficiency LED lighting, and other electricity-saving measures are provided to customers.

In addition to the weatherization programs, the Company operates in the retail space as well, providing incentives that drive residential customers and their contractors to choose high performing gas heating and hot water heating appliances and controls. By moving consumers and contractors away from lower performing appliances, our rebates are helping to transform the market for equipment and train customers to consider not just up-front cost but lifecycle costs. To that end, low- or no-cost borrowing options, such as on-bill financing, are also made available to residential customers participating in the weatherization program. For those participating customers who are income-eligible, the Company pays 100% of the cost of energy improvements, eliminating one of the major barriers to participation.

For the C&I sector, the Company also works closely with retailers and distributors to ensure that high efficiency boilers, furnaces, kitchen equipment, water heaters, steam traps, and controls are an attractive choice for contractors, builders and end use customers. By providing a cash incentive, the programs are designed to reduce the barrier that a higher up front cost presents to C&I customers. In 2019, a loan program was introduced for C&I gas customers to help offset the remaining up-front cost not covered by the program's cash incentive.

For both residential and C&I customers, new construction programs provide both technical assistance and training, as well as cash incentives to ensure that new buildings are built and equipped to high energy efficiency standards. This assistance is provided not only by Northern's key account managers, but supplemented by engineering and design-build firms that are familiar with both good building design and with our incentive programs, which can help customers cover the additional cost of more efficient designs.

Over the 2018-2020 Energy Efficiency Resource Standard term, Northern proposed to spend a total of $5.8 million in program costs, to be matched by $2.9 million in participants contributions, to achieve more than 110,000 MMBtu of natural gas savings in the first year of installation, and an estimated 1.7 million MMBtu in natural gas savings over the life of all the energy efficiency measures to be installed by our programs. In the residential programs, approximately one third of the lifetime savings is realized from the weatherization of existing homes in our territory, while about 18 percent comes from new construction; the remainder comes from high efficiency HVAC and hot water appliances.

For the commercial and industrial sector, which comprises more than 70% of total portfolio savings, the majority of savings come from custom projects performed in large businesses and manufacturers. The ability to realize such energy savings is dependent on a relationship of trust developed between the Company and customers and contractors over years of service. Beyond that, technical assistance, professional referrals and financial assistance help customers to overcome various barriers to the adoption energy efficient equipment and operations.

Current Energy Efficiency savings targets in the New Hampshire Division stem from the Three Year Plan for 2018-2020, as approved by the NH PUC in Docket No. DE 17-136. Target Residential and C&I customer efficiency savings from the 2018-2020 Plan were modeled in Section V, Demand Forecast. Appendix 4 provides the Company's annual plans for each of the three years, as well as actual results for 2018. In the IRP, the Company assumes that 2020 savings targets are extended throughout the planning period, which ends in 2024.

In addition to approving the EERS Settlement, the NHPUC Order in DE 17-136 also set the stage for the next Three-Year Plan. Specifically, the Order requires the parties to continue to meet in working groups to address areas such as Funding, Benefit-Cost, and Performance Incentive. The parties continue to meet and consider the outstanding issues that came out of the initial EERS development process. The Commission has retained a consulting firm to advise and facilitate the Evaluation, Measurement and Evaluation ("EM&V") working group regarding program evaluation.

Along with the other New Hampshire gas and electric utilities, Northern is in the very early stages of undertaking a statewide baseline and energy efficiency potential study to inform the development of the second Three-Year Plan under the EERS. Together with Staff from the Commission, along with their evaluation consultants, and the Office of Consumer Advocate, the utilities have selected a consulting firm that has recently undertaken three potential studies in Massachusetts. This baseline study, which is expected to kick off in July of 2019 and be completed within 12 months, will undertake a detailed analysis of the penetration and saturation of various kinds of gas-using equipment in both the residential and commercial/industrial sectors. This information, including the age and efficiency of such equipment, will provide the basis of a modeled estimate by end use (e.g., HVAC, hot water, process, etc.) of energy efficiency potential. It will also investigate the rates of adoption of high efficiency equipment occurring both naturally in the marketplace, and model the potential impact that energy efficiency programs can have to accelerate that adoption through incentives, loans, technical assistance and other interventions.

In the fall of 2019, a new facilitated process to plan for the 2021-2023 EERS Three Year Plan will commence. Commission Staff has issued a request for proposals and will select a facilitator to help guide stakeholders through a process expected to be similar to the one undertaken in the development of the first Three Year plan under the EERS. The utilities are scheduled to provide a draft plan in April of 2020, which will be followed by facilitated discussions with the parties. A final plan is to be submitted in September of 2020 and vetted in a formal proceeding before the Commission similar to the process used to establish the prior plan.

Because many of the strategies aimed at reducing natural gas consumption during peak periods include an increase in the use of electricity for heat and other end uses, and because the generation of electricity in our region is also dependent on the supply of natural gas, it is critical that utilities and regulators take a holistic approach to fuel use reduction. This approach, which takes all fuels into consideration, is often referred to as 'energy optimization'. Because reducing natural gas use by end users is not in and of itself a complete solution to the problem of limited capacity and high peak prices, the Company's gas and electric energy efficiency programs are integrated into a coherent whole.

Several studies in New Hampshire are investigating many of these inter-related opportunities, including one on fuel switching and energy optimization and is focused primarily on electric heat pump technologies; another focuses on the method by which energy efficiency programs' cost effectiveness is measured (namely with or without customer impacts included), and finally, the baseline / potential study described above. Together, these studies will help the utilities to develop a coherent suite of programs aimed at optimizing energy use for our customers, and capturing the opportunity to reduce both natural gas and electricity use while promoting economic development among our customers and within our communities over the next Three Year EERS period.

3. Energy Efficiency Resource Impacts

For the Maine Division, the Company added calculations to Efficiency Maine tables provided in Appendix 4, which are truncated to show only natural gas programs in order to estimate the average cost per MMBtu. The Company took the simple average of all residential and all C&I measures listed in Appendix L to the 2020-2022 Triennial Plan,[75] and multiplied by the annual MMBtu savings for residential and C&I customers provided in Appendix B to get lifetime MMBtu savings. The Company then divided the cost of residential and C&I measures, which includes EMT's program and administrative costs as well as participant costs, by lifetime savings to yield an average cost per MMBtu. This calculation makes no adjustments for time value of money and assumes 100 percent persistence of savings over the life of the measures to be installed. The results for FY 2022 were $4.87 per MMBtu for residential customers and $2.74 per MMBtu for C&I customers. Please see page 4 of Appendix 4.

Similarly, the Company modified its "Program Cost-Effectiveness - 2020 PLAN" table from the EERS Settlement to add average cost per MMBtu calculations. Again, the Company calculated the average cost as Total Cost, including both Company and Customer Cost and divided by lifetime savings. For the New Hampshire Division, the results were $8.85 per MMBtu for residential customers and $4.31

[75] PROPOSED TRIENNIAL PLAN FOR FISCAL YEARS 2020–2022, Efficiency Maine Trust, Appendix L – Measure List and Screening, provided in Excel format.

per MMBtu for C&I customers. Again, this calculation makes no adjustments for time value of money and assumes 100 percent persistence of savings over the life of the measures to be installed. Specific underlying differences in assumed savings per dollar of investment in energy efficiency in each state are not known, but the results in both divisions appear reasonable. Table VI-1 provides the New Hampshire Division calculation.

Table VI-1: Northern New Hampshire 2020 Energy Efficiency Plan

	Total Resource Benefit / Cost Ratio	Utility Costs ($000)	Customer Costs ($000)	Total Costs ($000)	Annual MMBTU Savings	Lifetime MMBTU Savings	Total Cost / Lifetime MMBTU
Program Cost-Effectiveness - 2020 PLAN							
Residential Programs							
Home Energy Assistance	0.98	$ 410.2	$ -	$ 410.2	2,055.3	41,991.6	$ 9.77
ENERGY STAR Homes	1.13	$ 201.7	$ 86.9	$ 288.6	1,486.0	36,212.0	$ 7.97
Home Performance with Energy Star	1.02	$ 218.4	$ 62.1	$ 280.5	1,547.1	26,682.0	$ 10.51
ENERGY STAR Products	1.26	$ 337.0	$ 221.7	$ 558.7	4,351.3	72,102.4	$ 7.75
Home Energy Reports	0.82	$ 93.3	$ -	$ 93.3	2,110.0	7,320.0	$ 12.75
Sub-Total Residential	**1.10**	**$ 1,260.7**	**$ 370.8**	**$ 1,631.5**	**11,549.7**	**184,308.0**	**$ 8.85**
Commercial, Industrial & Municipal							
Large Business Energy Solutions	1.93	$ 726.1	$ 500.5	$ 1,226.6	19,311.0	285,853.4	$ 4.29
Small Business Energy Solutions	1.83	$ 407.5	$ 268.4	$ 675.9	9,382.7	159,340.6	$ 4.24
C&I Education	0.00	$ 18.6	$ -	$ 18.6	-	-	$ -
Sub-Total Commercial & Industrial	**1.87**	**$ 1,152.1**	**$ 768.9**	**$ 1,921.0**	**28,693.7**	**445,194.0**	**$ 4.31**
Total - 2020 PLAN	**1.52**	**$ 2,412.8**	**$ 1,139.6**	**$ 3,552.4**	**40,243.4**	**629,502.0**	**$ 5.64**

In terms of Resource Capability and Deployment Timing, the Company is interested in the Design Year and Design Day impact on Planning Load due to the implementation of Energy Efficiency measures over the planning period. In order to assess this impact, the Company temporarily adjusted its forecasting model remove the Energy Efficiency savings and recorded the Design Year and Design Day Planning Load in the fifth year of the planning period. These were compared to the Design Year and Design Day Planning Load in the fifth year of the planning period with Energy Efficiency savings modeled as described in the Section IV, Demand Forecast. The results showed that in the fifth year of the planning period, the residential programs in both divisions reduced Design Year Planning Load by 88,604 Dth and reduced Design Day Planning Load by 662 Dth. By comparison, the C&I programs in both divisions reduced Design Year Planning Load by 166,909 Dth and reduced Design Day Planning Load by 1,519 Dth in the fifth year of the planning period. Taken together, the Energy Efficiency programs are projected to reduce Northern's Design Day requirements by over 2,000 Dth by the end of the planning period.

In terms of Fuel Security and Price Stability, Energy Efficiency is a favorable investment. So long as the measures installed remain in place and the buildings remain occupied, efficiency savings are expected persist over the lifetimes of the measures installed. Once a unit of demand is no longer required, the incremental fuel once needed to serve the need is no longer needed. Similarly, the avoided incremental fuel will not be purchased so there is no exposure to price volatility. The ongoing reduction in the need for fuel to heat a building or provide other services also means a reduction in environmental emissions.

Energy Efficiency provides meaningful local economic development and job opportunities. New Hampshire has 11,733 jobs in Energy Efficiency in 2019, an increase of 3.5% from 2018 to 2019. The largest number of these energy efficiency employees work in high efficiency HVAC and renewable heating and cooling firms, followed by ENERGY STAR and efficient lighting, and Energy Efficiency employment is primarily found in the construction industry.[76] Maine has 8,647 jobs in Energy Efficiency in 2019, an increase of 4.0% from 2018 to 2019. The largest number of these energy efficiency employees work in high efficiency HVAC and renewable heating and cooling firms, followed by other energy efficiency products and services, and Energy Efficiency employment is primarily found in the construction industry.[77]

EMT's Triennial Plan reports jobs impact at approximately 10 job-years annually. In a study done by UMASS Amherst in April 2019, job creation estimates were evaluated for the state of Colorado regarding energy efficiency investments. Estimates show 6.2 direct jobs per $1 million in investments in building retrofits and industrial efficiency in Colorado, and another 6 indirect and induced jobs, as shown in Table VI-2 below.[78] Total spending for natural gas Energy Efficiency in Maine, including both EMT and Customer costs, is approximately $2 million annually, and Northern's New Hampshire total Energy Efficiency costs are approximately $3.5 million annually. Taken together, this level of Energy Efficiency spending would support up to 66 jobs using the UMASS Amherst study estimates.[79]

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[76] Energy Employment by State — 2019, A Joint Project of NASEO & EFI, U.S. Energy and Employment Report 2019, New Hampshire section, page 1-4 of 7.

[77] Ibid, Maine section, page 5 of 7.

[78] Department of Economics and Political Economy Research Institute (PERI), University of Massachusetts-Amherst: A Green Growth Program for Colorado, April 2019, page 50

[79] 5.5 ($million) times 12 (Direct, Indirect + Induced Jobs) = 66.

Table VI-2: Estimate of Job Creation from Energy Efficiency

TABLE 13
Job Creation in Colorado through Energy Efficiency Investments
Job creation per $1 million in efficiency investments

	Direct Jobs	Indirect Jobs	Direct + Indirect Jobs total	Induced Jobs	Direct, Indirect + Induced Jobs Total
Building retrofits	6.2	2.7	8.9	3.3	12.2
Industrial efficiency	6.2	2.4	8.6	3.7	12.3
Electrical grid upgrades	3.9	1.4	5.3	2.1	7.4
Public transport expansion/upgrades	10.1	2.6	12.7	3.2	16.0
Expanding high efficiency automobile fleet	0.0	0.0	0.0	0.0	0.0

Sources: See Appendix 2.

Lastly, in terms of Health and Safety, there could be limited health risks associated with the work required to install insulation and various efficiency measures. However, efficiency assessments are likely to identify any existing hazards, such as mold or structural issues, which improves safety by alerting residents or occupants and any remedies implemented will improve Health and Safety.

D. Long-Term Capacity Resources

Northern has acquired a portfolio of long-term capacity 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 vaporization 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 capacity portfolio with short-term supplies delivered by others to its distribution system or to Granite interconnects ("Delivered Service" or "Delivered Supply").

1. Overview of Capacity Portfolio

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, TGP and MN US to Northern city gates along the Granite system

- Interconnections between Portland Natural Gas Transmission System ("PNGTS") and Granite, located in Westbrook, Maine, Eliot, Maine and Newington, New Hampshire
- Interconnections between Tennessee Gas Pipeline Company ("Tennessee" or "TGP") and Granite, located in Haverhill, Massachusetts and 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 city gates

Northern's long-term resource portfolio is summarized below in Table VI-3, 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-3: Northern Long-Term Resources by Capacity Path (MDQ in Dth)

Capacity Path	Resource Type	Max Daily Quantity	Method of Assignment	Status
Iroquois Receipts Path	Pipeline	6,434	Company-managed	Existing
Tennessee Niagara Capacity	Pipeline	2,327	Capacity Release	Existing
Tennessee Long-haul Capacity	Pipeline	13,109	Capacity Release	Existing
Algonquin Receipts Path	Pipeline	1,251	Company-managed	Existing
Tennessee Firm Storage Capacity	Storage	2,644	Capacity Release	Existing
Dawn Storage Path	Storage	39,863	Capacity Release	Existing
Lewiston On-System LNG Plant	Peaking	6,500	Company-managed	Existing
Existing Long-Term Capacity		**72,128**		**Existing**
Portland XPress Project (11/2020)	Pipeline	9,965	Capacity Release	Pending
Atlantic Bridge Capacity (11/2020)	Pipeline	7,500	Capacity Release	Pending
Pending Long-Term Capacity		**89,593**		**Pending**
Westbrook XPress Project (11/2022)	Pipeline	9,965	Capacity Release	Proposed
Proposed Long-Term Capacity		**99,558**		**Proposed**

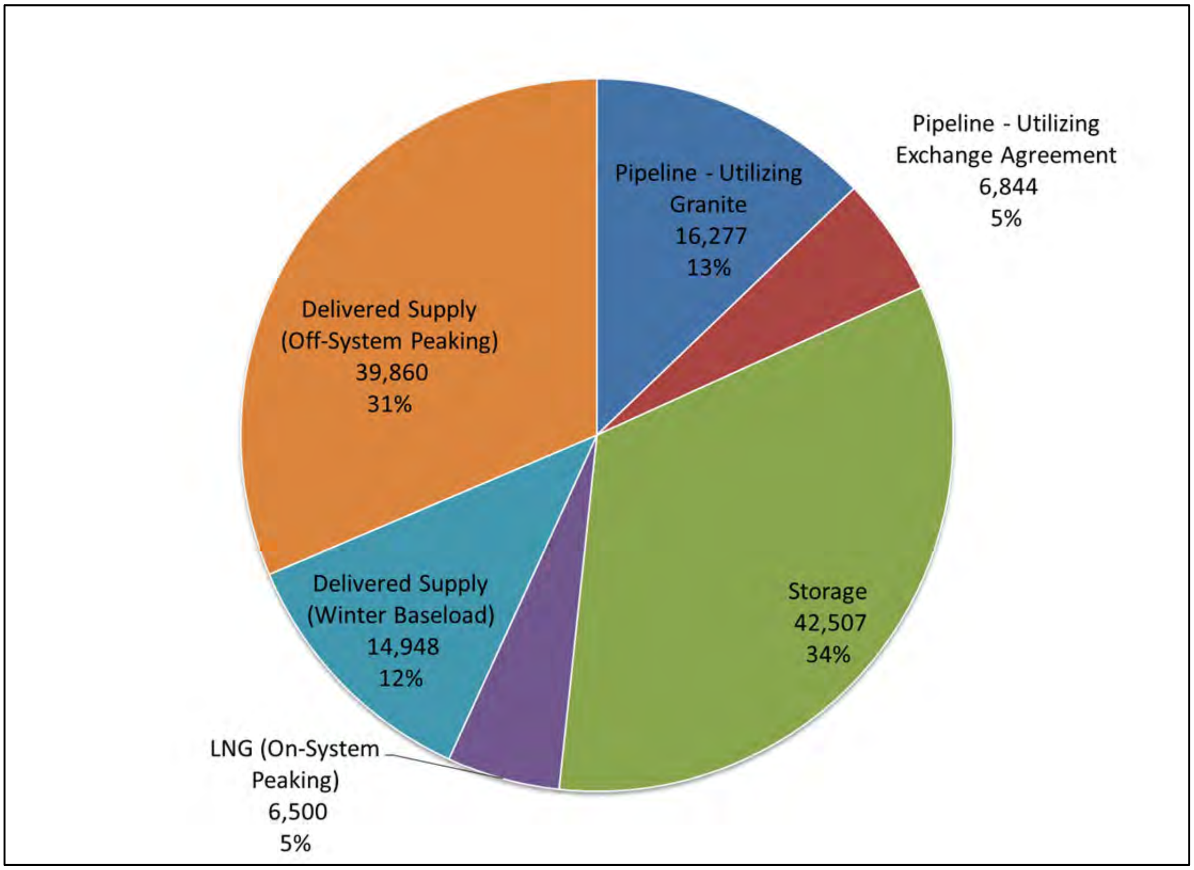
Resource narratives for each long-term resource path listed in Table VI-3 are provided below. Although not listed in the table above, Granite capacity is essential to Northern's portfolio and is used to deliver most of the capacity paths above. Also not listed above is the Bay State Exchange Agreement, 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.

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 sales service load requirements. Delivered Supplies are not assigned to retail marketers under the Delivery Tariffs, so Northern considers only the requirements of Sales Service customers when evaluating its need for Delivered Supplies. The actual amount of Delivered Supplies varies and is projected year to year. For the upcoming winter of 2019/20, 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. These Delivered Supplies comprise 43% of the Company's total MDQ of 126,936 Dth for the upcoming 2019/20 Winter Period. Clearly, the MDQ of these delivered supplies is very significant relative to the MDQ of Northern's long-term resources. The addition of pending Atlantic Bridge and Portland XPress Capacity Paths for the 2020/21 Winter Period and of the proposed Westbrook XPress Capacity Path for the 2022/23 Winter Period will reduce the Company's need for Delivered Supplies. Table VI-4 provides a summary of Northern's 2019/20 Winter Period portfolio by resource type, including Delivered Supply. Figure VI-1 provides this information in graphical form. Table VI-4 also reflects additional Granite capacity that currently has no associate upstream supply. Northern's contract quantity on Granite will increase from 115,000 Dth to 122,000 Dth for the 2019/20 Winter Period. This additional Winter Period Granite capacity will either be assigned to retail marketers or held by Northern for flexibility to purchase additional Delivered Supplies for the 2019/20 Winter Period, if needed.

Table VI-4: Current Northern 2019/20 Winter Period Portfolio by Resource Type

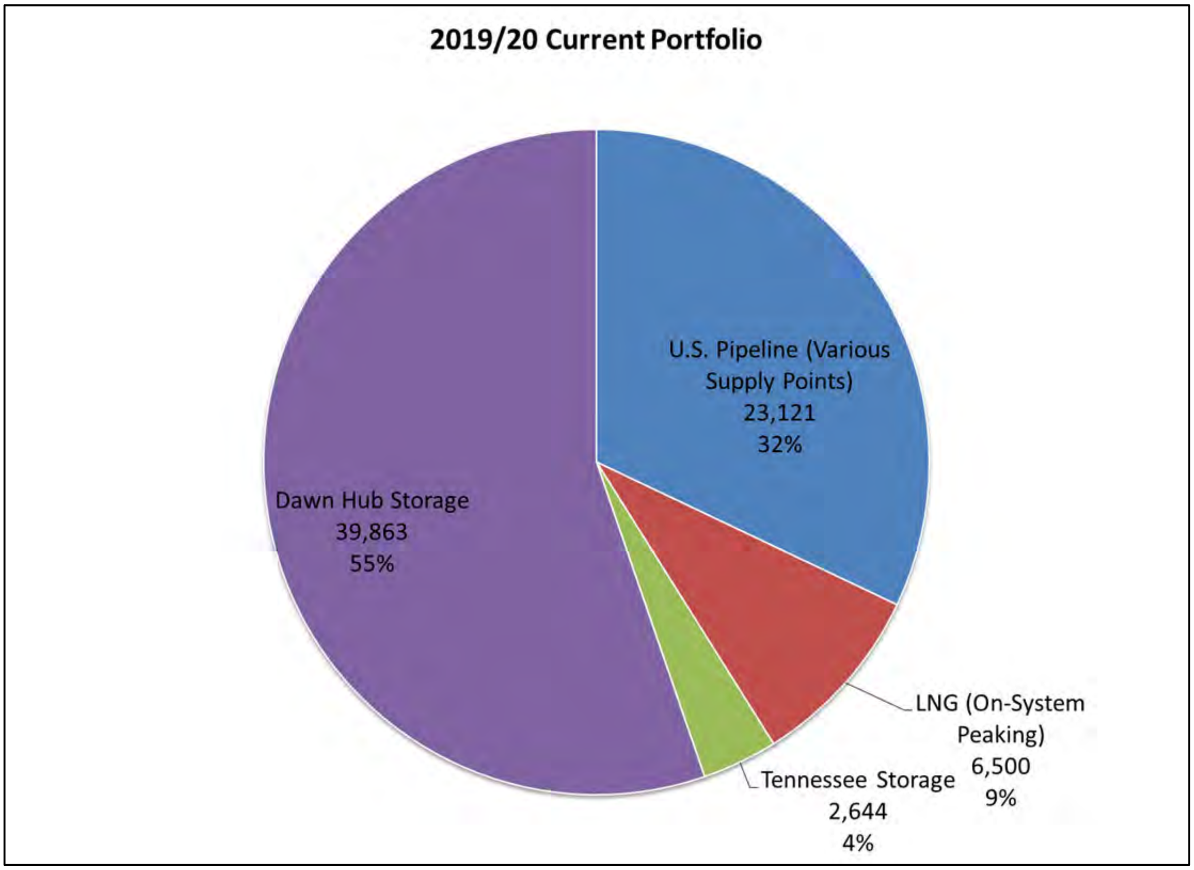
Resource Type	MDQ (Dth)
Pipeline - Utilizing Granite	16,277
Pipeline - Utilizing Exchange Agreement	6,844
Storage	42,507
LNG (On-System Peaking)	6,500
Delivered Supply (Winter Baseload)	14,948
Delivered Supply (Off-System Peaking)	39,860
Total Supply Resources	**126,936**
Additional Granite Capacity (Currently No Upstream Supply)	8,408
Total Capacity Resources	**135,344**

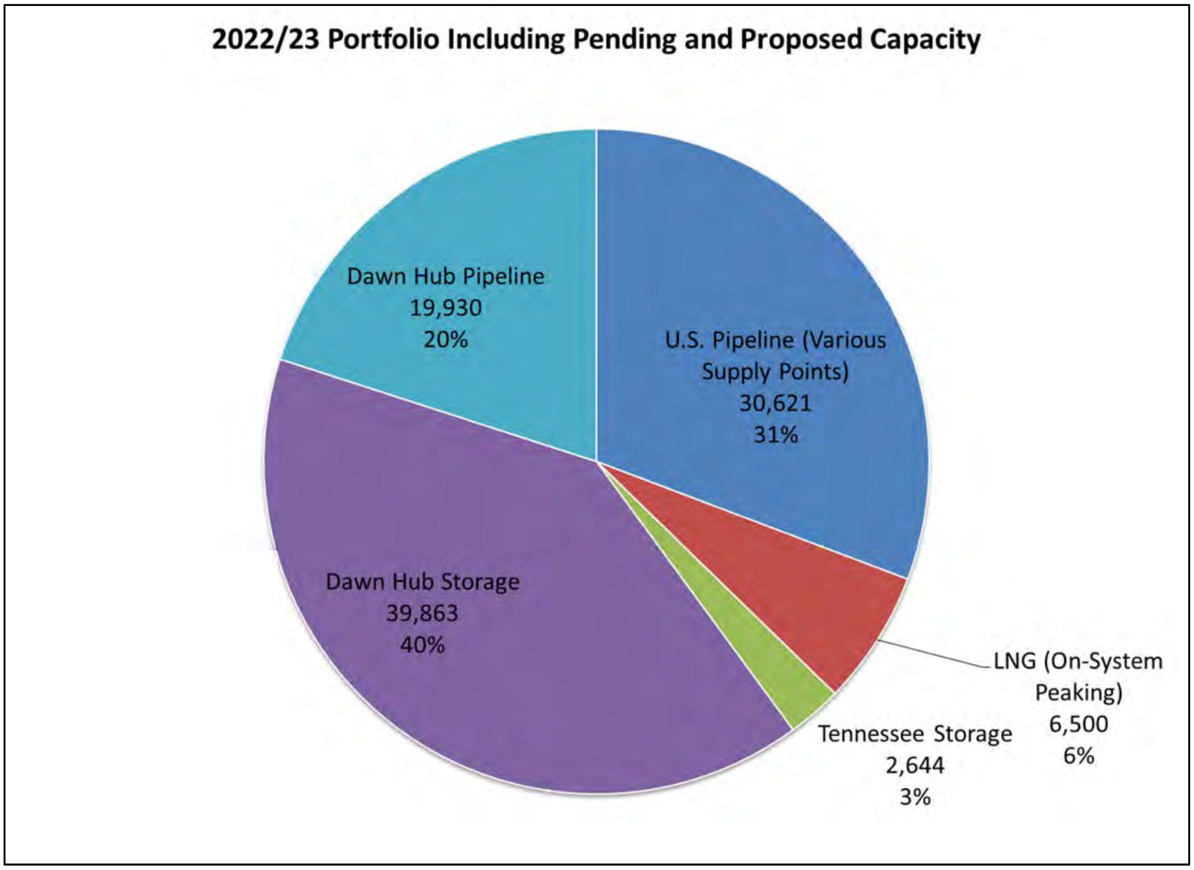
Figure VI-1: Current Northern 2019/20 Winter Period Portfolio by Resource Type



Northern seeks to maintain diversity among its long-term resources in terms of delivering upstream pipelines and supply sources. Dawn Hub Storage and Dawn Hub Pipeline supplies access Northern's system via PNGTS. Current U.S. Pipeline and Tennessee Storage supplies access Northern's system via TGP or the Bay State Exchange Agreement. When Atlantic Bridge is added to the long-term portfolio, this will add new U.S. Pipeline supply, which will access Northern's system via MN US. Northern's LNG plant is located in Lewiston, Maine on its distribution system and accesses supply via annual contracts for LNG supply and trucking. 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. However, Northern's ability to enhance diversity has been limited by the fact that expansion projects from the south have been limited relative to expansion projects from the north. 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 for the upcoming 2019/20 gas year and the long-term portfolio expected for the 2022/23 gas year, including both pending and proposed resources.

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





2. Existing Supply Resource Narratives

Northern Utilities' long-term capacity 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-5 provides a listing of Northern's long-term pipeline and underground storage existing, pending and proposed contracts, organized by capacity path, including contract end / renewal dates, and receipt and delivery zones.

Table VI-5: Pipeline Transportation and Underground Storage Contracts by Capacity Path

Capacity Path	Vendor	Contract ID	Contract End Date	Receipt Zone	Delivery Zone
Iroquois Receipts	Iroquois	181003	10/31/2024	Waddington	Wright
Iroquois Receipts	Tennessee	95196	10/31/2022	TGP Zone 5	TGP Zone 6
Iroquois Receipts	Tennessee	41099	10/31/2022	TGP Zone 5	TGP Zone 6
Iroquois Receipts	Algonquin	93002F	10/31/2020	Mendon, MA	Brockton, MA
TGP Niagara	Tennessee	5292	3/31/2025	TGP Zone 5	TGP Zone 6
TGP Niagara	Tennessee	39735	3/31/2025	TGP Zone 5	TGP Zone 6
TGP Long-haul	Tennessee	5083	10/31/2023	TGP Zone 0, L	TGP Zone 6
Algonquin Receipts	Texas Eastern	800384	10/31/2024	Leidy Storage	Lambertville, NJ
Algonquin Receipts	Algonquin	93201A1C	10/31/2020	Lambertville, NJ	Taunton, MA
TGP Firm Storage	Tennessee	5195	3/31/2025	TGP Zone 4	TGP Zone 4
TGP Firm Storage	Tennessee	5265	3/31/2025	TGP Zone 4	TGP Zone 6
Dawn Storage	Enbridge	LST086	3/31/2023	Dawn Hub	Dawn Hub
Dawn Storage	Enbridge	M12256	10/31/2033	Dawn Hub	Parkway
Dawn Storage	TransCanada	57901	3/31/2033	Parkway	East Hereford
Dawn Storage	TransCanada	57055	10/31/2032	Parkway	East Hereford
Dawn Storage	PNGTS	FTN-NUI-0001	10/31/2033	Pittsburg, NH	Newington, NH
Portland Xpress	Enbridge	TBD	10/31/2040	Dawn Hub	Parkway
Portland Xpress	TransCanada	TBD	10/31/2040	Parkway	East Hereford
Portland Xpress	PNGTS	TBD	10/31/2040	Pittsburg, NH	Newington, NH
Westbrook Xpress	Enbridge	TBD	10/31/2037	Dawn Hub	Parkway
Westbrook Xpress	TransCanada	TBD	10/31/2037	Parkway	East Hereford
Westbrook Xpress	PNGTS	TBD	10/31/2037	Pittsburg, NH	Newington, NH
All Capacity Paths	Granite	16-100-FT-NN	10/31/2020	NA	Northern

a) Iroquois Receipts Path

The ‘Iroquois Receipts’ path initiates at the Iroquois Gas Transmission (“Iroquois”) interconnect with TransCanada in Waddington, New York, which delivers into Tennessee at Wright, New York. A small portion of deliveries on this path feed into Granite at the Pleasant Street interconnect with Tennessee in Haverhill, Massachusetts, while the majority feeds into the Bay State Gas system at Agawam, Massachusetts and Brockton, Massachusetts via Tennessee and Algonquin. This path utilizes the Bay State Exchange Agreement. The portion of this path that delivers into Granite is assigned via capacity release and the portion that delivers to Bay State is assigned to marketers of delivery service customers as a Company-managed resource.

b) Tennessee Niagara Capacity

Northern has entitlements on two transportation contracts on the Tennessee Gas Pipeline 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 Tennessee to Pleasant Street on its corresponding firm Granite capacity for transport to Northern city gates. This path is assigned to marketers of delivery service customers via capacity release.

c) *Tennessee Long-haul Capacity*

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. This path is assigned to marketers of delivery service customers via capacity release.

d) *Algonquin Receipts Path*

Northern combines Texas Eastern Transmission Company ("TETCO") capacity with Algonquin long-haul capacity to access Leidy storage in Pennsylvania, which is a liquid supply hub. Northern's Algonquin contract includes receipt capacity at the interconnection between Algonquin and TETCO's Zone M3 at Lambertville, New Jersey and at the interconnection between Algonquin and Transcontinental Gas Pipe Line ("Transco") in Zone 6 at Centerville, New Jersey. This capacity has primary delivery rights to Bay State's Algonquin city-gate at Taunton, Massachusetts. This path utilizes the Bay State Exchange Agreement and is assigned to marketers of delivery service customers as a Company-managed resource.

e) *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 maximum withdrawal quantity is up to 4,243 Dth/day. The primary receipt meter in this transportation contract is the FS-MA storage withdrawal meter, and the primary delivery meter is at Pleasant Street, the interconnection between Tennessee and Granite. Northern receives this gas on its corresponding Granite capacity to make deliveries to Northern city gates. This path is assigned to marketers of delivery service customers via capacity release.

f) *Dawn Storage Path*

The Dawn Storage Path provides 4.0 Bcf of storage that can deliver up to 39,863 Dth/day, sourced from Dawn Storage during the winter or via purchases at the Dawn Hub year round. Northern holds firm transportation capacity for this path on Enbridge, TransCanada and PNGTS which resulted from contract restructuring and incremental commitments under PNGTS' C2C project and TransCanada's 2015 New Capacity Open Season. The Dawn Storage Path is assigned to marketers via capacity release.

g) Lewiston On-System LNG

The Lewiston LNG facility is an important resource within Northern's portfolio. Northern relies on the Lewiston plant to produce up to 6,500 Dth per day, which corresponds to approximately two days of onsite storage. The Lewiston LNG facility offers advantages not available from other supply resources such as flexibility that cannot be attained by the pipeline deliveries since pipeline supplies require steady takes over the course of the gas day (10 am – 10 am EST). In contrast to the ratable schedule of pipeline deliveries, 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. 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. LNG is assigned to marketers of delivery service customers as a Company-managed resource.

h) Atlantic Bridge

Atlantic Bridge is pending capacity in the Company's portfolio, which was approved by the Maine Commission in Docket 2016-00229. Northern's capacity on the project is 7,500 Dth/day. Atlantic Bridge involves expanding the Algonquin pipeline system and adding compression in Weymouth, Massachusetts, in order to provide adequate pressure to deliver gas northward into Maritimes. The Algonquin capacity provides for receipts from either Millennium at Ramapo, New Jersey or Tennessee's Zone 5, 300 Leg at Mahwah, New Jersey. When the Algonquin capacity goes into service, Northern will acquire downstream capacity on Maritimes with a primary delivery point in Lewiston, Maine.

The southern portion of the Atlantic Bridge project, providing for deliveries to customers on the Algonquin system, is in service. Deliveries to customers on Maritimes require the construction of the Weymouth compressor station, which has been delayed due to permitting challenges. The project has received its critical permits and the projected in-service date of the full Atlantic Bridge path is mid-2020. Deliveries to customers on Maritimes, including Northern, require the construction of the Weymouth compressor station, which has been delayed due to permitting challenges. Enbridge has received critical air quality permits related to the proposed new compressor station in Weymouth, Massachusetts, and the full project is expected to be in service by mid-2020. This capacity will be assigned to marketers via capacity release.

i) Portland Xpress Project (PXP)

PXP is pending capacity in the Company's portfolio, which was approved by the Maine Commission in Docket 2018-00040. Northern's capacity on the project is 10,000 Dth/day. The PXP project enhances Portland Natural Gas Transmission System ("PNGTS") capacity by adding a compressor in Eliot, Maine. Northern's capacity is on Phase III of the project, which has an expected in service date of November 2020. This capacity will allow Northern to transport gas from the Dawn Hub in Ontario, Canada to Granite State Gas Transmission, Inc. ("Granite") at Newington, New Hampshire and other delivery points on the PNGTS system for a 20 year initial term. PNGTS has acquired corresponding upstream capacity on TransCanada and Enbridge and will assign that capacity to Northern for effect on the in service date. PNGTS received approval of their PXP Phase III certificate February 21, 2019 and accepted the certificate on March 6, 2019. This capacity will be assigned to marketers via capacity release.

j) Westbrook Xpress Project (WXP)

WXP is proposed capacity in the Company's portfolio, which was submitted for approval of the Maine Commission in Docket 2019-00101 and for approval of the New Hampshire Commission in Docket DG 19-116. Northern's capacity on the project is 10,000 Dth/day. The WXP project enhances Portland Natural Gas Transmission System ("PNGTS") capacity by adding a compressor in Westbrook, Maine. Northern's capacity is on Phase III of the project, which has an expected in service date of November 2022. This capacity will allow Northern to transport gas from the Dawn Hub in Ontario, Canada to Granite State Gas Transmission, Inc. ("Granite") at Newington, New Hampshire and other delivery points on the PNGTS system for a 15 year initial term. Northern has separately acquired corresponding upstream capacity on TransCanada and Enbridge, and seeks approval from both commissions of the full capacity path. This capacity will be assigned to marketers via capacity release.

k) 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. Granite 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. Northern releases portions of its Granite capacity as part of released capacity paths and also assigns portions of its Granite capacity as peaking capacity.

l) 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 base load 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 Iroquois Receipts path. 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.

3. Capacity Portfolio Resource Impacts

In terms of Financial Cost, Appendix 5 includes annual detail of commodity charges, demand charges, utilization rates and average cost per Dth of Northern's Capacity Resources by capacity path over the planning period. Much of this information is redacted to protect Northern's leverage with its counterparties and vendors. Northern's portfolio includes several legacy contracts, which are largely depreciated and have very low demand charges. Certain of Northern's newer capacity contracts are tied to pipeline expansion projects and therefore involve higher demand charges. Most of Northern's capacity reaches to liquid supply points, which allows for the purchase of affordable commodity. Northern's average cost per Dth reflects the expected utilization of each resource. Although there is a wide range of unit cost across the different capacity paths, taken as broad groups, Northern's pipeline and storage capacity are comparable to the evaluated prices shown earlier for Energy Efficiency. The delivered cost per unit of LNG supply is higher than pipeline and storage resources because LNG involves the cost of liquefaction, over the road transport, storage and eventual vaporization. Although average LNG costs are higher than pipeline and storage, LNG is needed for fewer days during the year. The flexibility of LNG adds value to the portfolio.

Northern's existing Capacity Resources provide significant Resource Capability that could not be replaced in today's marketplace at comparable prices. Indeed, acquiring expansion capacity on pipeline and storage projects requires long-term commitments and high fixed charges. Constructing new LNG facilities is similarly a costly endeavor. However, Capacity Resources such as those in the portfolio can provide significant Resource Capability. Deployment Timing for pipeline expansions is currently approximately 4 years. Timing to construct a new LNG facility is likely comparable.

In terms of Fuel Security, the Capacity Resources in Northern's portfolio are renewable, meaning that Northern has an ongoing right to retain the capacity for use well into the future. In addition, the capacity accesses locations where supply is generally plentiful and reliably available. The same cannot be said for Delivered Supplies. In addition to high availability of supply, pricing at the supply sources the

Capacity Resources access is generally competitive which provides for low and stable pricing. Again, the same cannot be said for Delivered Supplies.

In terms of Environmental Impact of the Capacity Resources, Northern researched relevant data for each capacity path. Northern compiled CO2e emissions by state as reported by several of the pipelines in Table VI-6 below. Though Northern mapped out the approximate length of each capacity path, sufficient data was not available to correlate reported emissions with the length of the capacity path and total pipeline deliveries in order to estimate the share of reported emissions associated with Northern's use of the capacity paths. Thus, it is important to note that the reported pipeline emissions in Table VI-6 represents the aggregate emissions for all path states, and is not specifically reflective of Northern's use of these paths. Northern notes that some capacity paths have a "null point" along the path such that aggregate flows do not physically flow the entire length of the path. For example, the Tennessee Long-haul Capacity path is 1,780 mile long however significant volumes of gas are injected into the pipeline including in the Marcellus region such that Gulf of Mexico receipts to not physically flow through to New England. Northern was able to identify the number of compressor stations along each capacity path, but was unable to identify the size (horsepower) associated with each station. Lastly, Northern estimated the diesel emissions associated with over the road trucking of LNG to its facility in Lewiston, Maine. Assuming 100 round trip deliveries from Everett, Massachusetts annually, Northern estimates CO2 emissions to be 46 metric tons. The recent pipeline expansions Northern has participated in, including the Portland Xpress, Atlantic Bridge and Westbrook Xpress projects have involved the addition of compression facilities rather than new pipeline. These expansions also provide incremental energy supply to the states in which Northern operates.

Table VI-6: Reported Emissions and Pipeline Characteristics for Current Portfolio

Existing / Pending and Proposed Capacity	Resource Type	Status	Max Daily Quantity	Total Reported Pipeline Emissions for Path States (Metric Tons of CO2e)*	Appx. Path Length (mi)	Total Compressor Stations along Path	Supply Basin(s)
Iroquois Receipts Path	Pipeline	Existing	6,434	NA	410	9	WCSB or Marcellus/Utica
Tennessee Niagara Capacity	Pipeline	Existing	2,327	3,568	450	10	WCSB or Marcellus/Utica
Tennessee Long-haul Capacity	Pipeline	Existing	13,109	93,417	1,780	31	LA/ Gulf Coast
Algonquin Receipts Path	Pipeline	Existing	1,251	24,230	510	8	Leidy Storage
Tennessee Firm Storage Capacity	Storage	Existing	2,644	3,636	440	10	Western Marcellus
Dawn Storage Path	Storage	Existing	39,863	NA	800	2	WCSB or Marcellus/Utica
Portland XPress Project	Pipeline	Pending	9,965	NA	800	2	WCSB or Marcellus/Utica
Atlantic Bridge Capacity	Pipeline	Pending	7,500	24,230	335	8	Eastern Marcellus
Westbrook XPress Project	Pipeline	Proposed	9,965	NA	800	2	WCSB or Marcellus/Utica

*Self reported data, available from the EPA: https://ghgdata.epa.gov/ghgp/main.do

Existing LNG Plant	Resource Type	Status	Max Daily Quantity	Diesel Emissions Assoc. with Trucking (Metric tons of CO2)	Appx. Over Road (mi)
Lewiston On-System LNG Plant	Peaking	Existing	6,500	46	26,800

*Trucking emissions source: http://business.edf.org/files/2014/07/EDF-Green-Freight-Handbook.pdf page 13

Existing / Pending and Proposed Capacity	99,558

In terms of Economic Development and Jobs, the Capacity Resources reflect traditional energy industry infrastructure and employment. Although most of the capacity paths are upstream of Maine and New Hampshire, the pipelines that deliver to and interconnect with Granite and Northern do require inspection and operations and maintenance work. As of 2019, Maine has 85 workers in natural gas[80] and New Hampshire has 35 workers in natural gas.[81] In terms of local job creation associated with recent pipeline expansion projects, PNGTS reports in their application for the Portland Xpress Project that approximately 40 worker would be required in Westbrook, Maine, another 85 workers would be required at the Eliot, Maine Compressor Station and 15 workers would be required at the Dracut, Massachusetts Meter and Regulator station as part of project construction.[82] These are local jobs in and around the Company's service area; both Eliot and Dracut are border towns to New Hampshire.

E. Short Term Supply and Price Risk Management

1. Annual Resource Acquisition

While the Company's acquisition of capacity resources is a long-term endeavor, each year the Company purchases supplies to fill the capacity and arranges for asset management services to mitigate costs for customers and to reduce pipeline scheduling risk. The Company's supply activity is explained in detail and reviewed by both the Maine and New Hampshire Public Utilities Commissions in periodic Cost of Gas filings.

The Company's supply procurement process begins with an Annual Sales Forecast. In determining its supply requirements, the Company utilizes its latest forecasts of monthly gas supply requirements under Normal Year, Design Year and Design Day scenarios, as well as recent sendout experience from the outgoing winter period, adjustments to account for projected retail choice activity and capacity assignment requirements, and upcoming changes to the retail program.

In advance of each spring, the Company conducts an annual asset management arrangement ("AMA") and Delivered Baseload supply Request for Proposals (RFP). The annual RFP for asset management services is used to fill existing long term capacity, to ensure that scheduling services will be provided by experienced and reliable counterparties, and to provide revenue that offsets the cost of capacity for the benefit of customers. Since Northern's gas supply portfolio is not currently sufficient to cover its design requirements during the winter, market area baseload delivered supplies are purchased along with the AMA RFP. These baseload supplies are typically purchased as a common daily volume for the 151 day period of November through March and the 90 day period of December through February, with prices indexed to the NYMEX Last Day Settle each month plus a fixed physical basis price. This

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80 Energy Employment by State — 2019, A Joint Project of NASEO & EFI, U.S. Energy and Employment Report 2019, Maine section, page 3 of 7.

81 Ibid, New Hampshire section, page 3 of 7.

82 PNGTS PXP Application, Table 2 Land Requirements, 20181127-3006 FERC PDF (Unofficial), 11/27/2018.

pricing structure insulates customers from the volatility of daily index prices. The pending and proposed capacity is expected to replace Delivered Baseload purchases.

Notwithstanding the additional need for peaking supply, the Company structures its delivered baseload purchases and AMA contracts to ensure that supply available under the portfolio will satisfy design forecast requirements to the maximum extent possible while providing an economic combination of baseload and swing supplies, and reserving sufficient flexibility to adjust volumes on a monthly or daily basis as needed. Where practical, AMAs are structured to give prospective asset managers information about how often the capacity will be unencumbered by Northern over the course of the year, for example during summer periods where assets are determined to fall outside of the economic dispatch and are therefore not needed to meet customer needs, so they can provide their best (highest value) offers for the right to manage the capacity. Table VI-7 provides a six-year history of the revenue received under Asset Management Arrangements, which have served to reduce the cost of capacity to customers.

Table VI-7: History of Asset Management Revenue [REDACTED]

Year	Demand Costs	AMA Revenue	AMA Revenue as % of Demand Costs
2019-2020	$ 39,947,225	[redacted]	
2018-2019	$ 42,757,127		
2017-2018	$ 37,059,380		
2016-2017	$ 39,763,664		
2015-2016	$ 40,788,808		
2014-2015	$ 44,506,260		
Period Average	$ 40,803,744		

In addition to the AMA and Delivered Baseload supply purchases, the Company purchases Delivered Peaking supplies and LNG via RFPs. The Company's current long-term supply portfolio is not capable of meeting design day requirements. To ensure adequate supply during the coldest days, the Company conducts an RFP for delivered peaking supply and an RFP for LNG supply. The Company compares the Design Day and Design Year forecasts to the supplies available following the AMA and Baseload RFP and from the LNG plant, and then determines how much delivered peaking supply is needed to meet forecast requirements on the coldest day and throughout the winter. These requirements are reflected in the peaking RFP and resulting contracts as the Maximum Daily Quantity (MDQ) and the Annual Contract Quantity (ACQ) or Maximum Seasonal Quantity (MSQ). When possible, RFPs for delivered peaking supply are structured to ensure availability of adequate supply to meet locational needs and provide operational flexibility, such as non-ratable, day ahead and intraday nominations that allow for increases or decreases over weekends, while limiting exposure to daily market area index pricing which can be extreme on the coldest days, when peaking supply is most likely to be needed. Earlier in 2019, Northern purchased delivered peaking supply on multi-year basis, which will meet the majority of the Company's delivered peaking requirements for the coming winters.

Adequate LNG is purchased to fill the Company's LNG plant in Lewiston, ME. Since Northern's LNG plant has limited storage capability, Northern issues RFPs for LNG supply that are structured to provide daily refill capability sufficient to maintain the plant's planning capability of 6,500 Dth/day throughout the winter. The current LNG contract provides for delivery of up to 5 truckloads per day. Refill deliveries are received during the summer for replacement of LNG that has boiled off.

2. Price Risk Management

The Company operated a financial hedging program on behalf of customers in both Divisions which had been in place when Unitil purchased Northern Utilities from NiSource in December 2008. The original financial hedging program was structured to purchase NYMEX futures contracts under both price-based and time-based criteria in order to stabilize prices, with sales of NYMEX contracts occurring upon futures contract expiration. After experiencing financial losses under the program, Northern redesigned the hedging program to eliminate price-based purchases of futures contracts, recognize the hedging value of physical resources such as underground storage and introduce criteria whereby purchases of futures contracts were suspended in response to high as prices rise and futures contracts that appreciated significantly would be sold before they expire. After continued losses, Northern redesigned the hedging program again to introduce out of the money call options on futures contracts instead of futures contract, with the goal of protecting against exposure to very high price increases. Options contracts had the advantage of avoiding downside price risk, such that if prices fell after options were purchased, Northern's customers would still realize the lower prices while having protection from price increases above the option strike prices, whereas purchasing futures contracts simply locked in price. After assessing different option budget levels (shares of the futures prices to apply toward option purchases), Northern consistently saw the options contracts expire worthless and proposed to suspend the hedging program in 2017 and then terminate the hedging program in 2018.

A primary reason Northern terminated its financial hedging program was that the program sought to hedge NYMEX price risk even though NYMEX prices, reflecting the Henry Hub, had been stable with a stable outlook, while basis differentials between NYMEX pricing and index prices in New England were high, growing and volatile.

Northern provides price risk management by way of its physical procurement strategies. In the near term, as explained under Annual Resource Acquisition above, as feasible Northern structures its Delivered Supply and LNG contracts to be indexed to monthly rather than daily prices, in order to insulate customers from daily index pricing, which can become extreme particularly on very cold days when delivered peaking supplies are needed. Longer term, Northern has sought to acquire additional physical assets that allow greater access to supplies at locations where gas is plentiful and prices are competitive. For example, in 2018 Northern increased its underground storage capacity by 15 percent. in recent years and has regularly added pipeline capacity to its Capacity Portfolio that will allow for purchases are more liquid supply points such as the Dawn Hub. Northern's pending and proposed pipeline capacity, including its commitments to the Portland Xpress, Atlantic Bridge and Westbrook Xpress projects, will significantly reduce the Company's purchases of market area Delivered Supply and increase the purchases of gas at locations where gas is more plentiful and prices are more stable.[83]

Examples of the disparity in pricing among different supply points are provided in the Regional Market Overview part of Section III. See Figure III-13, Table III-6 and Table III-7.

[83] The pricing benefits of Northern's commitments to recent pipeline projects are in addition to the primary benefit of providing access to supply needed to reliably serve customers.

VII. Resource Balance

Key Takeaways

Key takeaways in this chapter include the following:

- *The Company has modified its Resource Balance calculations by comparing expected annual utilization rather than Annual Capacity Quantity to Normal and Design Year Planning Load to more accurately depict the adequacy of its Long-Term Capacity Portfolio to meet Planning Load.*
- *The Long-Term Capacity Portfolio is insufficient to meet Planning Load under Normal Year, Design Year and Design Day conditions throughout the Planning Period, covering the 2019/20 through 2023/24 gas years. The addition of Pending Capacity Resources (Atlantic Bridge and Portland XPress) beginning November 2020 and Proposed Capacity Resources (Westbrook XPress) beginning November 2022 will reduce the gap between Expected Long-Term Portfolio utilization and Planning Load, but additional capacity resources are needed.*
- *The Company addresses this gap for its Sales Service customers with delivered supply purchases, including baseload delivered supplies and off-system peaking supplies. Delivered supplies are purchased solely to meet the needs of Sales Service customer loads because they are not assignable the retail marketers. The Company has entered into a multi-year off-system peaking supply arrangement to address gap between the Normal Year, Design Year and Design Day Planning Load requirements and the capabilities of the Capacity Portfolio for Sales Service customer loads while the Company evaluates longer-term solutions.*

A. Introduction

Section VII provides information showing the difference between the Planning Load forecast, as determined in Section V, and the capacity of Northern's existing long-term resources, as shown in Section VI, Current Portfolio. The difference is known as the Resource Balance. Separate comparisons are provided, based on Normal Year requirements, Design Year requirements and Design Day requirements.

The approach to Normal and Design Year Resource Balance has been updated from the Company's 2015 IRP to better reflect the adequacy of the portfolio to meet the Normal and Design Year Planning Load forecasts. In the 2015 IRP, the Resource Balance compared the Annual Capacity Quantity ("ACQ") to the annual Normal and Design Year Planning Load forecasts, respectively. The Resource Balance in this IRP compares the expected resource utilization under Normal and Design Year conditions to the respective Planning Loads. This provides a more accurate assessment of Resource Balance, because excess capacity in periods of low demand is not artificially shown to offset capacity deficiencies in periods of high demand. Table VII-1 lists the Normal and Design Year utilization 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.

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

Normal Year Resource Utilization	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Iroquois Receipts Pipeline Path	982,351	975,890	975,890	975,890	982,351
Tennessee Niagara Pipeline Path	375,538	350,461	350,959	341,761	345,504
Tennessee Long-Haul Pipeline Path	2,033,343	1,934,404	1,937,546	1,846,736	1,872,034
Algonquin Receipts Pipeline Path	457,866	456,615	456,615	456,615	457,866
Tennessee FS-MA Storage Path	967,599	964,956	964,956	964,956	967,599
Union Dawn Storage Path	9,156,923	6,202,799	6,386,473	5,517,873	5,674,008
Lewiston LNG	125,000	125,000	125,000	123,938	124,120
Utilization of Existing Long-Term Capacity	**14,098,621**	**11,010,124**	**11,197,439**	**10,227,768**	**10,423,483**
PXP Dawn Pipeline Path	0	1,519,514	1,522,734	1,526,549	1,540,490
Atlantic Bridge Ramapo Pipeline Path	0	2,737,500	2,737,500	2,737,500	2,745,000
Utilization of Pending Long-Term Capacity	**14,098,621**	**15,267,138**	**15,457,672**	**14,491,817**	**14,708,973**
WXP Dawn Pipeline Path	0	0	0	1,491,003	1,502,118
Utilization of Proposed Long-Term Capacity	**14,098,621**	**15,267,138**	**15,457,672**	**15,982,820**	**16,211,091**

Design Year Resource Utilization	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Iroquois Receipts Pipeline Path	982,351	975,890	975,890	975,890	982,351
Tennessee Niagara Pipeline Path	375,538	351,351	351,351	346,595	349,024
Tennessee Long-Haul Pipeline Path	2,033,343	1,945,548	1,948,568	1,889,642	1,910,528
Algonquin Receipts Pipeline Path	457,866	456,615	456,615	456,615	457,866
Tennessee FS-MA Storage Path	967,599	964,956	964,956	964,956	967,599
Union Dawn Storage Path	9,420,640	6,690,809	6,859,839	6,100,442	6,271,880
Lewiston LNG	125,000	125,000	125,000	125,000	125,000
Utilization of Existing Long-Term Capacity	**14,362,338**	**11,510,169**	**11,682,219**	**10,859,139**	**11,064,249**
PXP Dawn Pipeline Path	0	1,519,514	1,522,734	1,526,549	1,540,490
Atlantic Bridge Ramapo Pipeline Path	0	2,737,500	2,737,500	2,737,500	2,745,000
Utilization of Pending Long-Term Capacity	**14,362,338**	**15,767,183**	**15,942,452**	**15,123,189**	**15,349,739**
WXP Dawn Pipeline Path	0	0	0	1,494,980	1,506,008
Utilization of Proposed Long-Term Capacity	**14,362,338**	**15,767,183**	**15,942,452**	**16,618,169**	**16,855,747**

The Resource Balance analysis provides guidance as to the adequacy of the current portfolio and the level of additional long-term resources that are required to reliably and cost-effectively meet Northern's planning load during the five-year planning period (i.e., the 2019/20 gas year through the 2023/24 gas year) covered in this IRP.

The remainder of this section includes table and charts depicting the following:

Part B, Normal Year Resource Balance;

Part C, Design Year Resource Balance;

Part D, Design Day Resource Balance.

B. Normal Year Planning Load Resource Balance

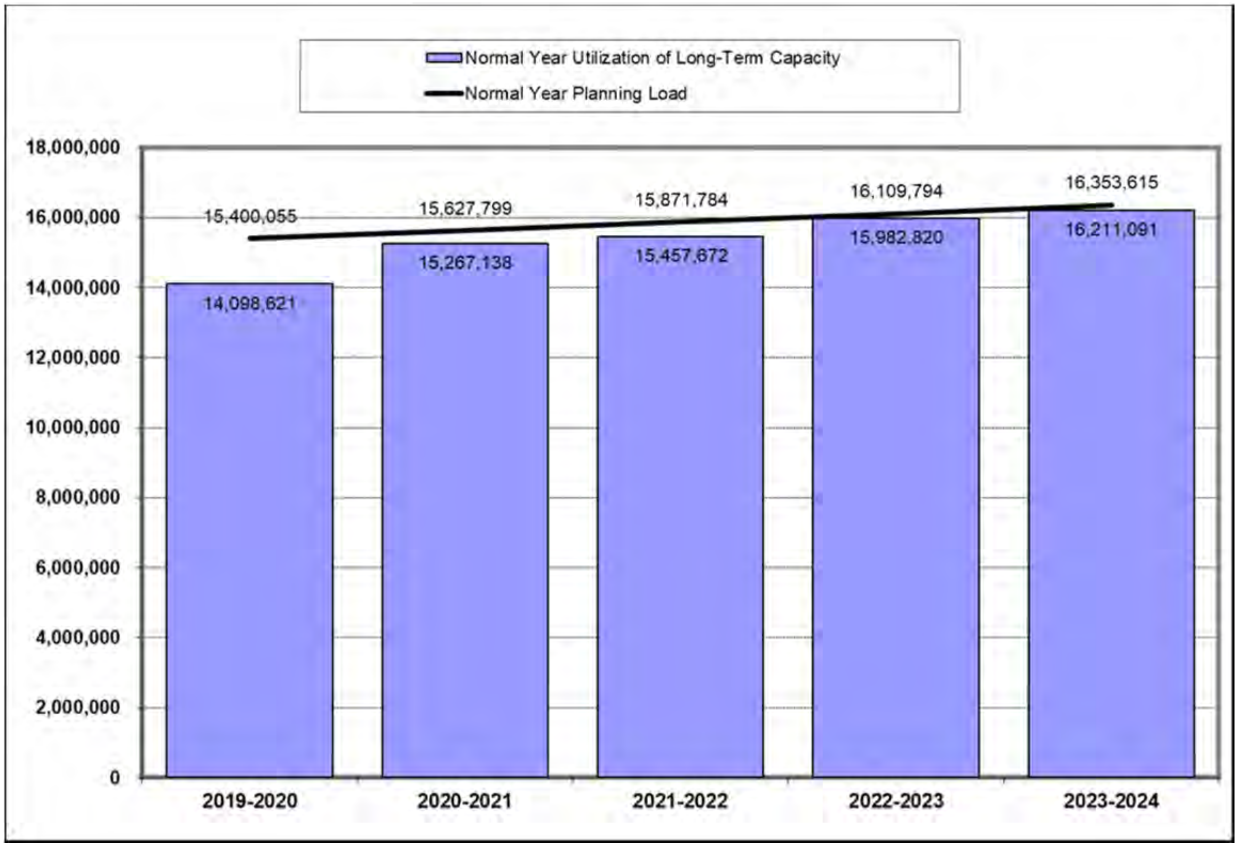
In calculating Resource Balance, Northern assumes renewal or replacement of all existing long-term resources, a November 2020 in-service date of the Atlantic Bridge and Portland Xpress projects and a November 2022 in-service date of the Westbrook Xpress project. All of Northern's current, pending and proposed long-term capacity resources provide reliable, cost-effective service.

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's Normal Year Planning Load Forecast is greater than the expected utilization of its Long-Term Capacity. In other words, Northern requires incremental supply to meet its Planning Load forecast under Normal Year weather conditions. However, the addition of the Pending Capacity Resources (Atlantic Bridge and Portland XPress) in November 2020 and the addition of the Proposed Capacity Resources (Westbrook XPress) in November 2022 starts a trend of decreasing requirements for incremental supply through the Planning Period covered by this IRP.

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

	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Normal Year Utilization of Long-Term Capacity	14,098,621	15,267,138	15,457,672	15,982,820	16,211,091
Normal Year Planning Load	15,400,055	15,627,799	15,871,784	16,109,794	16,353,615
Normal Year Resource Balance	**(1,301,434)**	**(360,661)**	**(414,112)**	**(126,974)**	**(142,524)**

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



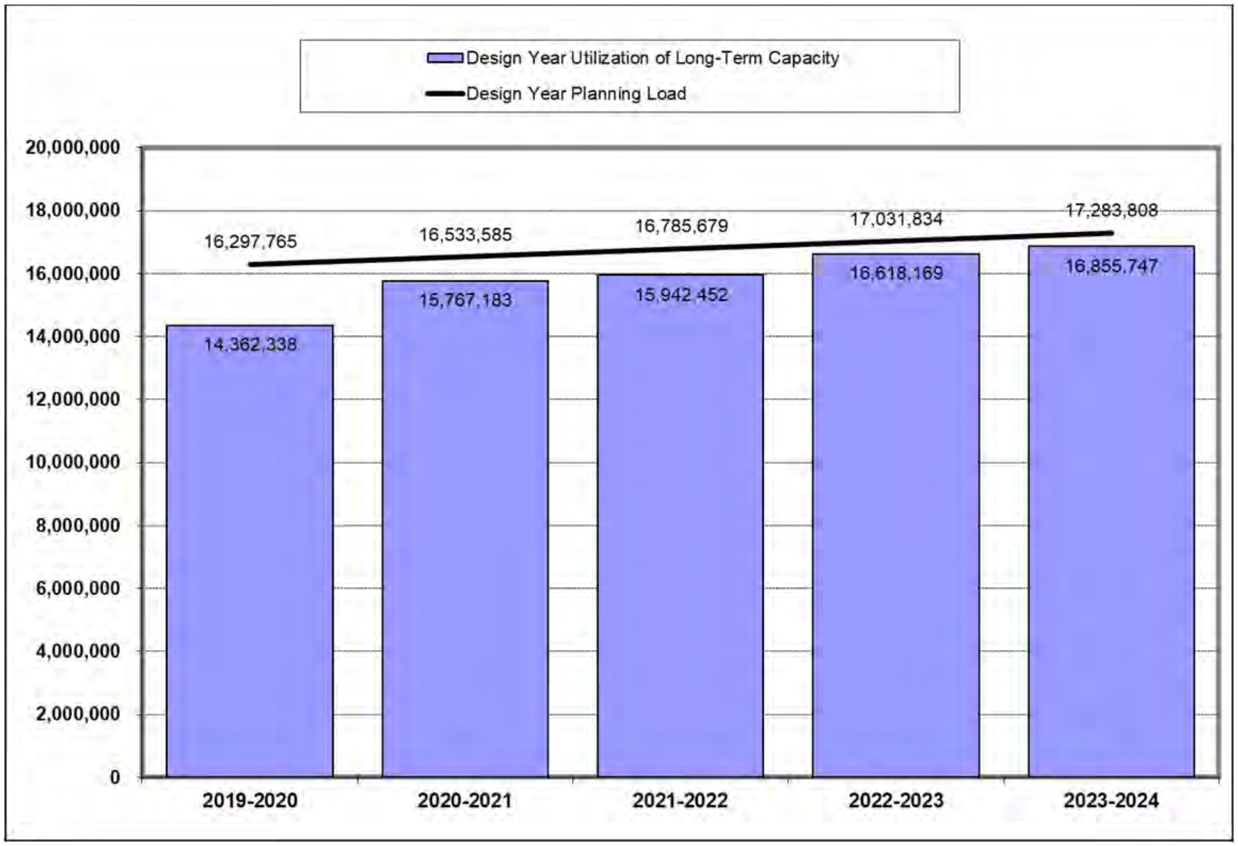
C. Design Year Planning Load Resource Balance

Table VII-3 provides the Design Year Resource Balance over the planning horizon and Figure VII-2 depicts the data graphically. As with the Normal Year Resource Balance, the Company's Long-Term Capacity is not sufficient to meet the Design Year Planning Load throughout the Planning Period, but the need for incremental supplies decreases because of the addition of the Pending and Proposed Capacity Resources.

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

	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Design Year Utilization of Long-Term Capacity	14,362,338	15,767,183	15,942,452	16,618,169	16,855,747
Design Year Planning Load	16,297,765	16,533,585	16,785,679	17,031,834	17,283,808
Design Year Resource Balance	**(1,935,427)**	**(766,402)**	**(843,227)**	**(413,665)**	**(428,061)**

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



D. Design Day Planning Load Resource Balance

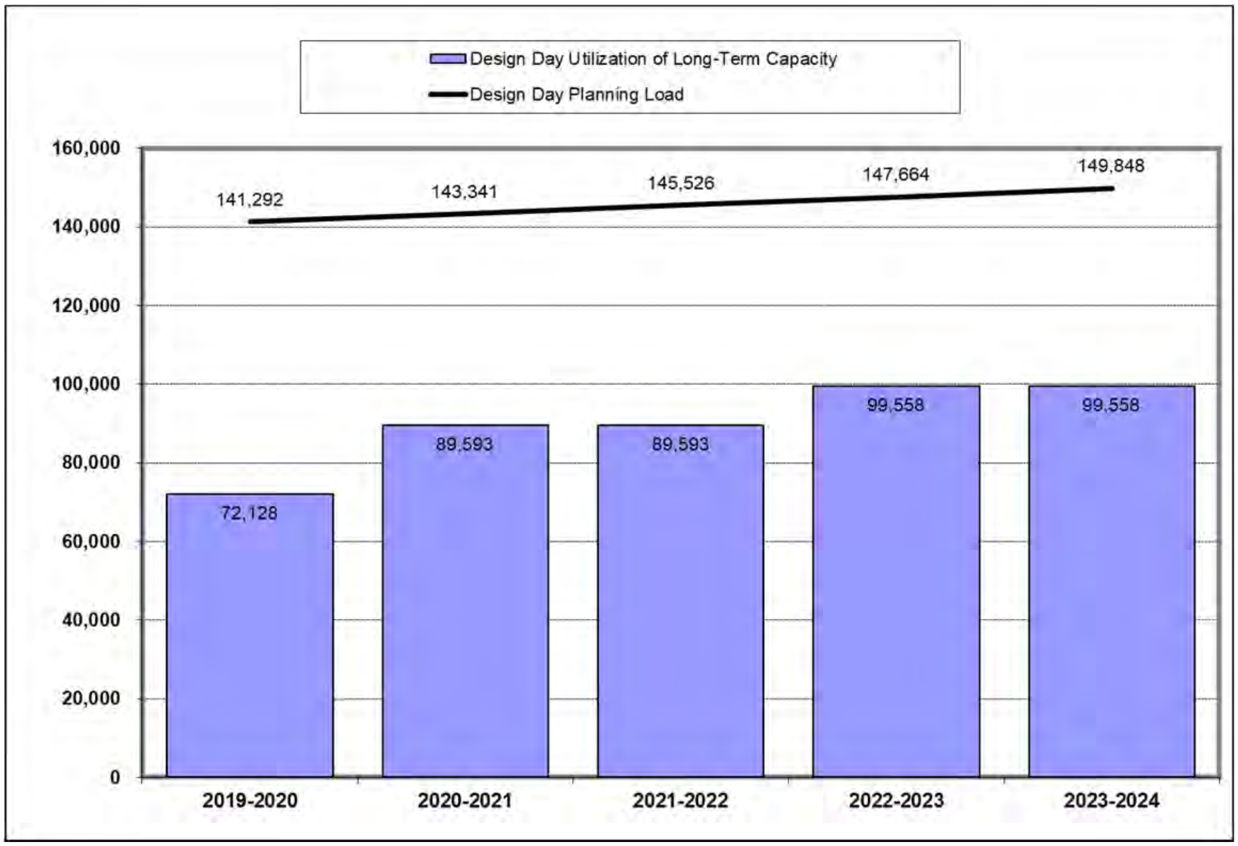
In order to align the timing of resource need with resource availability, the resource balance is was also prepared under Design Day conditions. Table VII-4 provides the Design Day Resource Balance over the planning horizon and Figure VII-3 depicts the data graphically.

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

	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Design Day Utilization of Long-Term Capacity	72,128	89,593	89,593	99,558	99,558
Design Day Planning Load	141,292	143,341	145,526	147,664	149,848
Design Year Resource Balance	**(69,164)**	**(53,748)**	**(55,933)**	**(48,106)**	**(50,290)**

The Design Day comparison of planning load and available resources tells a similar story as did the annual comparisons, indicating that Northern's long-term resources are not adequate to meet Planning Load under design day conditions. Northern's long-term resources are projected to be short of Design Day Planning Load by 69,164 Dth in 2019/20. The addition of the Pending and Proposed Capacity Resources helps to reduce the design day deficiency, but this is also offset by projected load growth through the planning period. 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)



As seen in both tabular and graphic form above, under Normal Year, Design Year and Design Day conditions, Northern's Long-Term Capacity Portfolio is insufficient to meet the forecast Planning Load. Northern addresses this deficiency on behalf of its Sales Service customers through the purchase of delivered supplies. Pursuant to both Maine and New Hampshire Delivery Service Terms and Conditions, delivered supplies are not assignable to retail marketers and so the Company considers only Sales Service customer requirements when entering into these types of purchases. Notably, as discussed in Section VI, the Company has entered into a four-year off-system peaking supply contract beginning November 2019. The Company expects that this off-system peaking supply contract will provide sufficient daily and annual supply volumes to address the Resource Balance deficiency for its Sales Service customers while the Company evaluates and develops longer-term capacity options.

In its Amended AESC 2018 Report, Synapse provided a summary of "Potential design day deficit" for each New England LDC.[84] The Report reasonably reflects Northern's capacity deficiency relative to Design Day Planning Load during the planning period, as shown above in Table VII-4 and Figure VII-3, particularly for gas year 2022/23. Note that absent the approval and timely placement into service of the proposed WXP capacity, which is for 10,000 Dth/day, and which was not known when Synapse published the Report, Northern's Design Day deficiency would be approximately in 2022/23 would be 58,100 Dth.[85]

Table VII-5: Design Day Deficit for Regional LDCs (MDth)

Table 9. Potential design day deficit (MDth)

	2017–18	2022–23	2027–28
National Grid (MA)	23.7	289.0	414.4
NSTAR Gas	10.6	7.4	57.0
Columbia of MA	-	-	-
Liberty (MA)	14.4	12.4	12.0
Berkshire Gas	14.5	3.3	4.9
Fitchburg Gas	-	-	-
National Grid (RI)	-	11.3	38.6
Yankee Gas	-	25.4	115.0
CT Natural	-	-	45.4
Southern CT	-	-	40.3
Liberty (NH)	-	16.4	40.8
Northern Utilities	47.0	59.3	76.4
Vermont Gas	-	-	-
Total	**100.2**	**324.4**	**844.7**

The comparison above of Design Day deficit by LDC highlights Northern's need for additional peaking capacity, and how large Northern's need is relative to other LDCs, many of whom are much larger than Northern. In the near term, Northern has met the majority of this shortfall by executing a multi-year contract for Delivered Peaking Supply. Section VIII reviews possible Long-Term resource options available to meet this deficiency on a long-term basis.

84 "Avoided Energy Supply Components in New England: 2018 Report", as amended October 24, 2018, Synapse Energy Economics, *et.al.* Table 9, p. 38.

85 48,106 Dth + 9,965 Dth (10,000 Dth less Granite losses of 0.35%, see Table VI-3) equals 58,071 Dth.

VIII. Incremental Resources Options

Key Takeaways

Key takeaways in this chapter include the following:

- *Potential future resource options that can meet Northern's Design Year and Design Day deficiency identified in the Resource Balance section include continuing to purchase Delivered Service, ideally under Long-Term arrangements if available, and pursuing Non-Pipeline Supply Resources.*
- *The Company has retained a consultant to help identify Non-Pipeline Supply Resources. Possible projects include adding storage to Northern's existing LNG facility in Lewiston, exploring options to construct a new LNG facility and looking for opportunities to purchase renewable natural gas (RNG).*
- *In support of the requirements of New Hampshire RSA 378:38, Northern developed a Resource Impact table that summarizes existing and potential resource options in terms of the Resource Impacts defined in Section VI.B. The summary includes the Company's 2023/24 Planning Load and Resource Balance in order to put resource capability into context.*

A. Introduction

In Section VIII, Northern identifies potential supply resource options that could meet the portfolio needs identified in the Resource Balance Section. Those needs, which reflect a lack of peaking resources, are refined further in Section IX, Preferred Portfolio, with the use of Load Duration Curves. As discussed in Section VI, Current Portfolio, the Company has entered into a multi-year peaking supply agreement to meet the majority of its anticipated peaking needs over the coming winter periods. The Company will also pursue all Energy Efficiency approved in each Division.

Northern intends to renew all existing Capacity Resources. Renewal dates are provided in Table VI-5. 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; and (iii) certain of the pipeline capacity is physically connected to Northern (or Granite) or is used to effectuate the exchange arrangement. Moreover, once turned back, legacy capacity typically cannot be reacquired.

As discussed in earlier sections, the Company has proposed to add new pipeline capacity to its Capacity Portfolio via the Westbrook Xpress Project. The Company submitted petitions to the Maine Commission in Docket No. 2019-00101, and the New Hampshire Commission in Docket No. DG 19-116 seeking approval of precedent agreements for the project. This proposed capacity has common features and impacts associated with the rest of the current portfolio. The capacity from Westbrook Xpress is already reflected in the Resource Balance calculations presented in Section VII.

Northern monitors new supply alternatives and opportunities by staying informed of 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 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, suppliers and other parties pursuing or offering solutions to supply challenges. These activities help Northern to identify developers and projects that could meet the needs Northern may require.

The rest of Section VIII includes the following:

Part B, Long-Term Delivered Supply, ;

Part C, Non-Pipeline Supply Resources, ;

Lastly, Part D, Resource Impact Summary, provides a tabular summary of Northern's existing portfolio and future resource options in terms of the Resource Impact categories identified in Section VI.

B. Delivered Supply

The Company currently relies on Delivered Supply to meet a significant portion of its supply requirements. Note that under the Delivery Service Terms and Conditions, Capacity resources in Northern's portfolio are allocated equitably among Sales Service and capacity assigned Transportation Service customers. However, incremental supply requirements due to shortfalls of the capacity portfolio are to be purchased by each retail marketer or by Northern to serve their respective customers. Thus, Northern's delivered supply purchases are intended for Sales Service customers.

Northern's Resource Balance in 2023/24 is projected to be approximately 50,000 Dth on Design Day and 428,000 Dth on Design Year. In recent years and as mentioned for upcoming years, Northern has been able to purchase comparable volumes as Delivered Supply. However, there are very few parties willing and able to provide a delivered peaking service sufficient to meet Northern's remaining requirements. The limited availability creates questions about the long-term certainty and availability of Delivered Supply and also impacts prices Northern can expect to pay for such service. If circumstances prevent a single or small group of suppliers from offering Delivered Supply at any point in the future, Northern would be unable to meet its supply obligations. This dynamic prompted Northern to contract for a multi-year service that commences this coming winter.

In terms of Resource Impacts, purchasing Delivered Supply under long-term arrangements provides additional fuel security relative to short-term (year-to-year) purchases. Northern has no specific information with regard to sourcing of such gas and associated environmental or health related impacts, and Northern would expect little if any economic development associated with such a resource option.

C. Non-Pipeline Supply Resources

Given the identified peaking need, Northern hired a full-time consultant to assist in identifying non-pipeline gas supply options. The consultant began working with Northern in March 2019. Working with the consultant, Northern has increased its awareness of non-pipeline activities in the region and begun to identify possible projects. Although this work is ongoing and to date no specific project commitments have been made, the Company has identified three potential project types it is either exploring already or intends to explore.

First, the Company is exploring the addition of expanded storage capability at its existing Lewiston LNG facility. The Company currently relied on the plant to produce 6,500 Dth/day during the coldest days of the year. The limiting factor on the plant's daily capability is the availability of storage. At the current plant rating, the facility has less than two days of onsite storage and the daily production target can be met in as few as 10 hours of operation. If the Company is able to cost-effectively add incremental storage capacity, it could better leverage existing vaporization capacity. Initial projections suggest onsite storage could be increased by approximately 50 percent, which might support an increase in daily production capability from 6,500 Dth to 10,000 Dth. Project economics have not been calculated although if such an upgrade were implemented, the average cost of supply may be on par or close to the current price Northern pays for LNG production. Deployment time associated with this type of project is initially projected to be between 12 and 18 months. Incremental capability that might be added would provide a high level of fuel security and support some local jobs during construction. Environmental and health and safety impacts are expected to be on par with the existing facility.

Second, the Company is assessing the feasibility of adding a new LNG facility to its system. Other LDCs are in the process of making similar investments, such as National Grid's Fields Point facility.[86] Based on the identified Resource Balance deficiency, Northern could utilize a LNG vaporization of up to 50,000 Dth/day and over 400,000 Dth seasonally. However, Northern may have locational limitations on its ability to receive LNG produced on its system at a single location, unless the project was to deliver into Granite. As such, a smaller facility(ies) may be effective. Lead time for a new LNG facility is projected to be 4 to 5 years, with a project delivering into Granite requiring longer lead time, due to FERC filing requirements. Although the Company is exploring the addition of a new LNG facility,

[86] https://www.ferc.gov/industries/gas/enviro/eis/2018/06-25-18-EA/CP16-121-EA.pdf

the effort is still in the exploratory phase. No project economics have yet been developed. If a new LNG facility were to provide adequate storage that allows for summer refill, lower and more stable commodity prices would be expected. Similarly, no qualitative assessments have yet been made such as those required under Northern RSA 378:38 or those otherwise included in Northern's qualitative assessment approach to resource evaluation, described in Section IX, Preferred Portfolio.

Lastly in terms of non-pipeline supply alternatives, the Company has been learning about renewable natural gas (RNG) and intends to monitor and assess opportunities to participate in RNG projects or simply purchase RNG from others. To date there have been no substantive opportunities identified.

D. Resource Impact Summary

The Company has assessed its current and identified incremental resource options to the extent they are defined and data is available in accordance with the Resource Impact categories identified in Section VI.B. Existing resources were discussed in Section VI, and possible future resource options have been discussed in this Section VIII. Table VIII-1 summarizes the various existing and future resources in terms of the Resource Impact categories. In addition, Table VIII-1 depicts the Company's long-term Resource Balance as of 2023/24, the fifth year of the planning period to provide context for the outstanding portfolio needs and relative capability of different resources. As reflected in the summary, there are pros and cons to be weighted with respect to each resource option or group of resource options and tradeoffs to be considered as incremental future resource options are considered. The following Section IX, Preferred Portfolio, discusses the Company's approach to resource evaluation including consideration of the factors shown in Table VIII-1 below. The Company envisions using this table (or some future version) serving as one of its assessment tools.

Table VIII-1: Resource Impact Summary - Existing and Future Resource Options [REDACTED]

		Financial Cost	Resource Capability	Deployment Timing	Fuel Security	Price Stability	Environment Impact	Economic Dev / Jobs	Health & Safety
	Metrics	*Annualized Cost / Dth (1)*	*Design Day, Design Year*	*Time needed to Implement*	*Control over Resource*	*Impact on Price Stability*	*CAA impact, GHG impact*	*Local Jobs, Investment*	*Injury Risk, Illness Risk*
2023/24 Planning Load			***149,848 Dth 17,283,808 Dth***						
Existing / Pending and Proposed Resources	Existing / Pending Pipeline Capacity	[redacted]	40,586 7,985,259	N/A	High - Renewal Rights	High - Liquid Markets	N/A	Low impact	Low risk
	Existing Storage Capacity	[redacted]	42,507 7,239,479	N/A	High - Renewal Rights	High - Liquid Markets	N/A	Low impact	Low risk
	Existing Lewiston LNG Plant	[redacted]	6,500 125,000	N/A	High - Ownership	Moderate- Winter Fill	N/A	Low impact	Low risk
	Incremental EE Savings - RES (2)	NH = $8.85 ME = $4.87	662 88,604	5 Years	Customer Ownership	N/A	Favorable- Avoids Emissions	Moderate	Low risk, Healthier when done
	Incremental EE Savings - C&I (2)	NH = $4.31 ME = $2.74	1,519 166,909	5 Years	Customer Ownership	N/A	Favorable- Avoids Emissions	Moderate	Low risk, Healthier when done
	Proposed Pipeline Capacity - WXP	[redacted]	9,965 1,506,008	3-4 Years, ISD Nov '22	High - Renewal Rights	High - Liquid Markets	N/A	Low - Some Initial	Low risk
2023/24 Existing / Proposed Resources			***99,558 Dth 16,855,747 Dth***						
2023/24 Resource Balance			***(50,290) Dth (428,061) Dth***						
Future Resource Options	Long-Term Delivered Supply (3)	[redacted]	variable 15 or 20 day	N/A	Uncertain	Uncertain - Few Sellers	N/A Unknown Imports	Low impact	Low risk
	Add Storage to Lewiston LNG Plant	TBD	~3,500 ~25,000	1+ Year	High - Ownership	Moderate- Winter Fill	N/A	Low - Some Initial	Low risk
	Future LNG Peaking	TBD	~40,000 ~15 days	4-5+ Years	High	High if Summer Fill	N/A	Initial, Some Ongoing	Low risk
	Future RNG Purchases	TBD	Unknown	Unknown	Unknown	Unknown	Positive- Low or No Emissions	Likely Positive	Unknown

(1) Annualized Cost of Portfolio Resources reflects modeled utilization; see Section IX and Appendix 5.

(2) Energy Efficiency Cost/Dth reflects upfront Utility and Customer costs divided by Lifetime MMBtu Savings, using publicly available data from the NH EERS Settlement and EMT's Triennial Plan for 2020 - 2022, without adjustments such as for discount rates. See Appendix 4 and Table VI-1. Resource Capability reflects modeled Planning Load savings under design conditions.

(3) Short-Term Delivered Supply is purchased for Sales Service customers only.

IX. Preferred Portfolio

Key Takeaways

Key takeaways in this chapter include the following:

- *Northern's approach to Long-Term planning and procurement includes providing resources that reliably meet design planning criteria while providing significant utilization upon being put into service, avoiding excesses of capacity, providing renewal rights, operational and contractual flexibility and enhancing low and stable pricing.*
- *Northern relies largely on qualitative assessment criteria, including the resource impact assessments called for under New Hampshire RSA 378:38, in its resource decision making process, assuming that based on quantitative analysis a given resource is comparably priced relative to available alternatives and the resource is shown to help meet design condition customer requirements.*
- *Northern may require regulatory pre-approval of significant contractual commitments undertaken to meet customer requirements at a reasonable cost.*

A. Introduction

As the Resource Balance section shows, Northern's long-term capacity resources (including existing, pending and proposed resources) are not sufficient to meet its design day, design year and normal year Planning Load forecast throughout the 5-Year Planning Period. The Company currently utilizes Delivered Supplies to meet the gap between design day and design year demands and long-term capacity resources for its Sales Service customer loads. For the reasons discussed in more detail in the Market Overview section of this IRP, Northern's portfolio objective is to reduce its dependency on Delivered Supplies and replace this with demand- and supply-side resources that will remain under the Company's long-term control.

The Company has made strides toward achieving this objective, beginning with reforms to the Delivery Service Terms and Conditions in both Maine and New Hampshire to assure that that the cost and benefits of supply-side capacity resources properly follow the customer whether the customer is supplied by the Company or a retail marketer. These reforms assured proper allocation of the costs needed to facilitate the long-term contracts the Company has entered into for the Atlantic Bridge, PXP and WXP new supply-side capacity resources. The Company has also entered into a multi-year off-system peaking Delivered Supply contract to best assure the availability and reasonable cost of peaking supply needed to meets its Sales Service supply requirements in the coming years . These actions will reduce the Company's exposure to price spikes and uncertain future availability of Delivered Supplies, as the Company evaluates and develops the Incremental Resource Options identified and discussed in the previous chapter.

The Company's Preferred Portfolio for the Planning Period presented in this Integrated Resource Plan is to maintain the Current Resource Portfolio outlined in Section VI, including all current demand- and supply-side resources, including the pending and proposed supply-side resources. Northern will need to continue to procure Delivered Supplies to supplement the Current Resource Portfolio to assure that it can meet Design Day and Design Year Planning Criteria for Sales Service customer loads until sufficient long-term resources can be developed or acquired. It should be noted that Northern did not specifically model the multi-year off-system peaking contract in its modeled cost analysis for this Integrated Resource Plan because the modeled cost analysis is meant to reflect the entire Current Resource Portfolio and the Planning Load requirements under both Normal and Design Year weather scenarios. Since the multi-year peaking supply contract is solely to meet Northern's Maine and New Hampshire Sales Service customer demands and is not assignable to retail marketers of Capacity-Assigned Delivery Service customers, this agreement was not included in the analysis. However, the Company did consider the price of the multi-year off-system peaking contract when forecasting the price of Incremental Supply needed to bridge the gap between Normal and Design Year Planning Loads and the Current Resource Portfolio.

Based on its modeled cost analysis, the Company has prepared the following for each year of the Planning Period.

- Design Cold Snap Analysis chart
- Winter and Summer Load Duration Curve charts for both Design and Normal Year
- CONFIDENTIAL Annual City-Gate Cost, Delivered Volumes and Unit Cost schedule for both Design and Normal Year

These charts and schedules are provided in Appendix 5 to this Integrated Resource Plan. These materials show in graphic and tabular format, Northern's projected use and cost of its supply-side resource to meet the Planning Load less projected demand-side energy efficiency savings already reflected in prior sections of the Integrated Resource Plan. One can see the significant impact that the pending and proposed supply-side resources will have in reducing Northern's long-term reliance on Delivered Supplies.

Northern plans to continue to pursue cost-effective means of reducing its reliance upon Delivered Supplies to meet its Design Day and Design Year Planning Criteria. As such this Section IX also 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 (including those identified in Section VIII).

The remainder of the Preferred Portfolio section is organized as follows:

Part B, Approach to Long-Term Planning, reviews the Company's portfolio planning objectives and goals;

Part C, Resource Evaluation Methods, reviews the analytical tools and qualitative assessments the Company uses in assessing resource commitments;

Finally, Part D, Regulatory Considerations, highlights the Company's efforts to comply with expectations of the Commissions that oversee the Company's procurement of supply resources, and the need for pre-approval of significant commitments and for consistency between jurisdictions.

B. Approach to Long-Term Planning

Northern takes the following approach to Long-Term Planning.

- Northern values a long-term resource portfolio of appropriate demand- and supply-side resources that is well-balanced with its projected Planning Load under Design Day and Design Year conditions throughout the Planning Period. Currently, Northern seeks to add resources to its long-term resource portfolio, but looks to do so as efficiently as possible by avoiding excessive surpluses of capacity.
- Northern values long-term resources that are well sized to satisfy identified resource needs and provide for considerable utilization as soon as the resource is brought into service. For this reason, the Company has presented evaluations of Year 1 impacts in support of proposed new capacity in its recent requests for pre-approval of pipeline commitments.
- Northern values long-term resources that Northern is able to control beyond the Planning Period. For example, the Company favors upstream pipeline capacity with renewal rights over Delivered Supplies with fixed termination dates and no renewal rights. Rights to renew capacity resources assure sustainable access to the resource.
- Northern values a portfolio with sufficient flexibility to reliably balance supply with daily, monthly and seasonal demand requirements. Northern's demand requirements can change dramatically from day to day during the Winter Period, especially. The Company puts a premium on resource flexibility as demand and market conditions change from day to day as well as year to year.
- Northern values access to liquid supply points with many buyers and sellers. This provides Northern with many options when seeking to purchase gas for its customers, as well as price transparency through published index prices and future pricing. Northern's distribution system is located in a supply constrained market with few buyers and sellers due to limited availability of supply and Northern is concerned about the sustainability of long-term reliance upon continued purchases of Delivered Supply. On the PNGTS and MN US portion of Northern's system, where the majority of the customer demand is located, there is very limited price transparency, with neither published index prices nor futures prices for supply on these pipes.

- Northern values the contribution that investments in energy efficiency provide in terms of meeting customer energy requirements cost-effectively, including benefits such as reducing environmental impacts and promoting local economic development. The development and approval of energy efficiency resources is actively pursued and overseen in both Divisions.
- Northern values compliance with all statutory and regulatory requirements related to natural gas supply.

C. 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 load requirements 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 regarding the adequacy of the portfolio and the appropriateness of potentially available incremental resources in satisfying identified resource needs.

- <u>Resource Balance Assessment</u> – Broadly identify incremental resource needs by comparing existing long-term resources to long-term planning load requirements, under the various weather and growth scenarios.
- <u>Landed Cost Analysis</u> – A landed cost analysis is developed to compare and screen various resource project options.
- <u>Decision-Making Process</u> – 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.
- <u>Qualitative Assessment</u> – 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 flexibility and diversity, location of delivery, renewal rights, other contractual issues, etc.
- <u>Modeled Cost Analysis</u> – If several 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. The timing of pipeline open season decisions

(when there may be only notice of a few weeks for the Company to determine whether it will participate in a proposed project) has necessitated the use of simpler analytical models. Load duration curves are used to assess utilization of resources coincident with the frequency and timing of resource needs. Cold snap analyses are used to assess adequacy of the portfolio.

Each of these steps described above are described further or demonstrated below. The Resource Balance Assessment was demonstrated in Section VII. Landed Cost Analysis, Decision-Making Process, Qualitative Assessment and Modeled Cost Analysis 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. This evaluation technique can also be applied to less than 100% load factor utilization scenarios. The Company has also utilized 5-month (November through March) and 3-month (December through February) baseload utilization profiles, which are especially appropriate as the need for Incremental Supply is during the Winter Period.

2. Decision-Making Process

Northern utilizes both quantitative and qualitative tools in making resource decisions. Quantitative tools are used to assess utilization of possible resources, including impact on the utilization of other portfolio resources, to estimate average delivered costs and to assess the impact of a potential resource in satisfying or contributing to unmet design Planning Load requirements. Once reasonably available projects are identified, they are screened using the Landed Cost analysis, and then modeled as described below. In cases where there is only one available resource, Northern’s quantitative tools are used to assess the resource relative to continuing to purchase Delivered Supply in terms of providing adequacy of resources and to access cost impacts.

So long as viable available projects are comparable in terms of price, Northern bases proposed resource decisions primarily on qualitative or non-price criteria. Thus, while resource decisions are informed by quantitative analyses (such as Modeled Cost Analysis) they 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's decision making, and to demonstrate that Northern's decisions are reasonable.

3. Qualitative Assessment

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

Resource Impacts: Non-price impact of proposed resources, including those identified in New Hampshire RSA 378:38 and discussed in Section VI.B., will be reviewed and assessed such that resource decisions minimize negative impacts on customers and the communities the Company serves generally.

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.

Mitigation of Price Volatility: Possible projects are reviewed in terms of whether they help to mitigate price volatility. The Company seeks to move its receipt points away from locations where gas prices are high and/or volatile and toward receipt points where gas prices are low and/or stable. Similarly, being able to replace winter period purchases with purchases made during the summer when prices are typically lower and more stable offer price volatility mitigation.

Contributions to Flexibility and 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.

Contract Renewal Rights: The flexibility of the renewal provisions of contracts, and conversely the permanence of project ownership, are assessed. Renewable access to capacity is highly valued in support of fuel security and sustainable resources. Renewal options provide tools to manage long term changes that may arise.

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.

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.

4. Modeled Cost Analysis

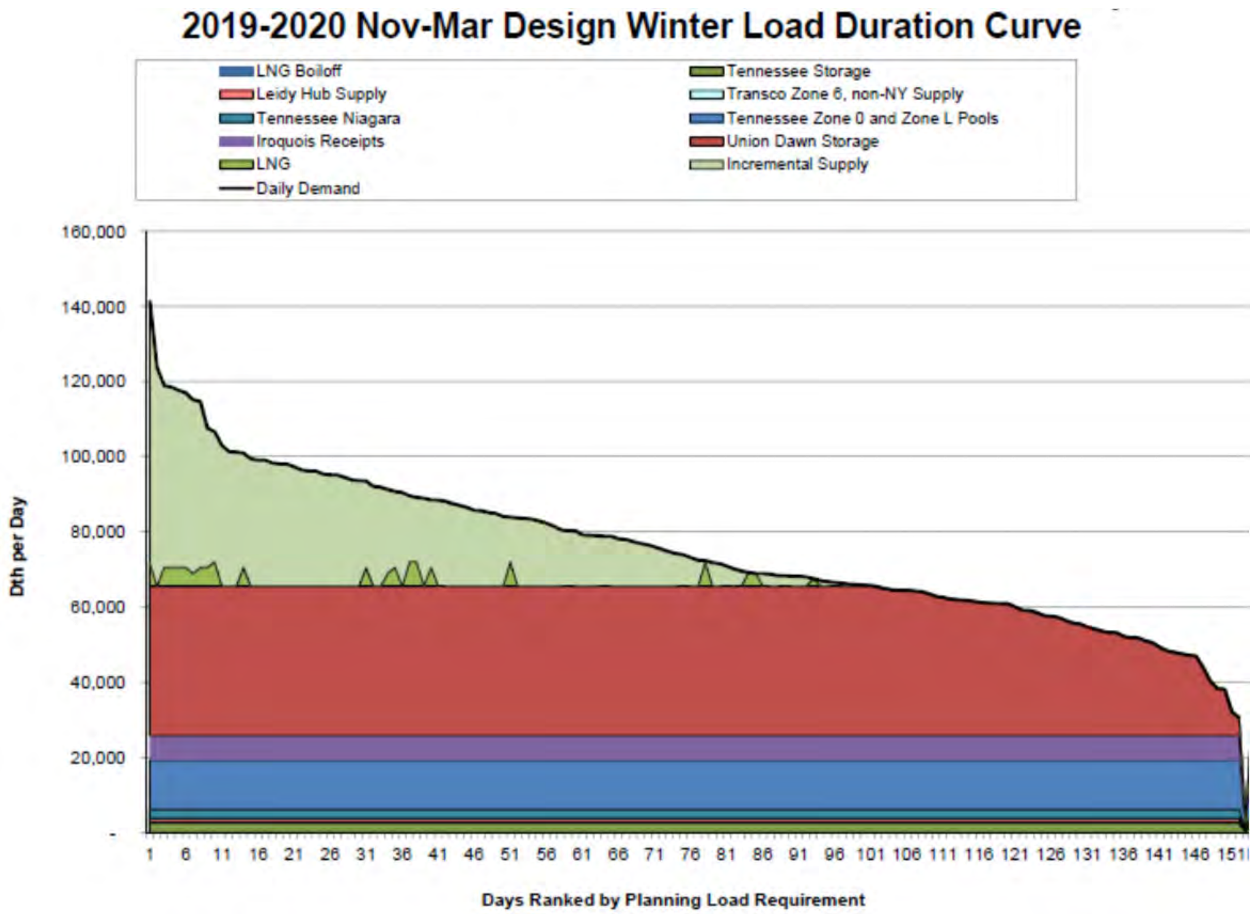
The first steps in long-term planning are to assess the adequacy of the existing portfolio and identify whether an incremental resource need exists. If a need exists, the characteristics of the need must also be assessed. The adequacy of the long-term portfolio is assessed by comparing supply available from existing resources to the Long-Term Planning Load forecast. Northern presented its Resource Balance analysis in Section VII. For example, the Resource Balance showed that Northern has a Design Day deficiency of approximately 50,000 Dth in 2023/24.

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[87] as described in Section V, Planning Load. 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. 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 green colored area labeled "Incremental Supply."

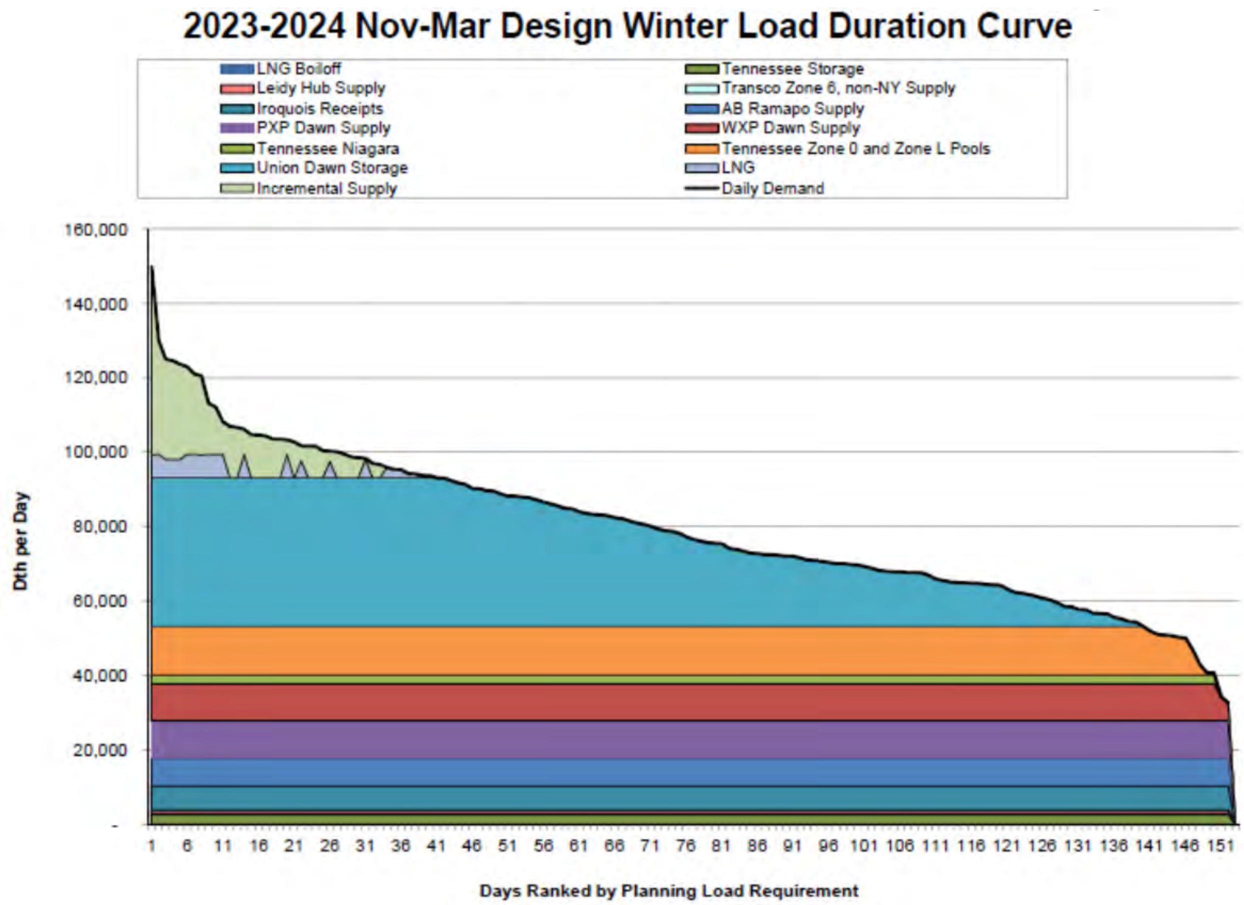
[87] Northern defines a Design Year as a design winter plus a normal summer.

Figure IX-1: Load Duration Curve, Design Winter 2019/20



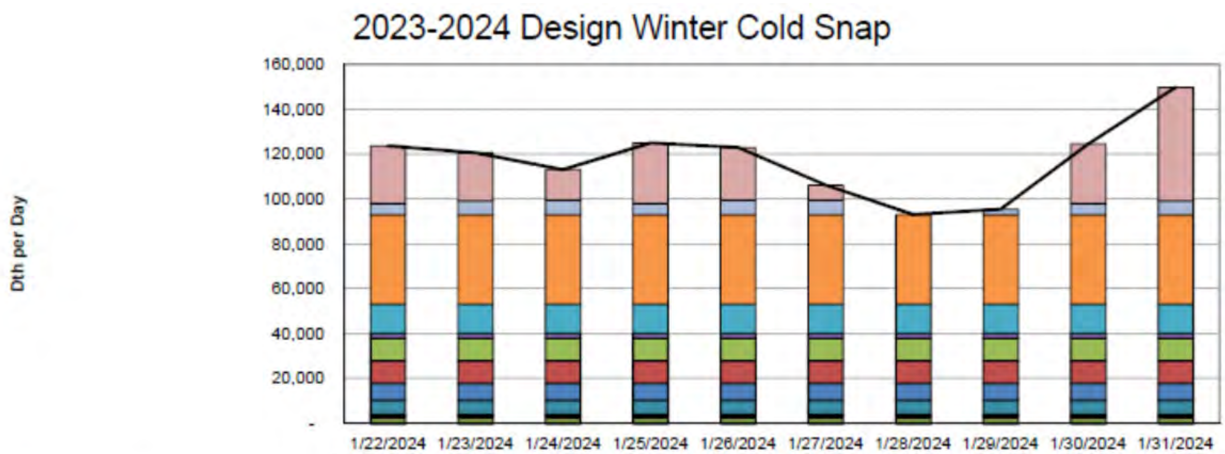
Load duration curves provide an informative depiction of incremental resource needs. Based upon visual inspection of the load duration curve, the existing portfolio would be unable to meet design planning load requirements for the coldest 95 days of the winter period, with some requirements offset by LNG production. Without conducting any further quantitative analysis, the area for Incremental Supply indicates a significant peaking need and additional need that could be met with either storage or pipeline capacity. In the recent years, Northern has made commitments to pipeline capacity, as discussed in Section VI, Current Portfolio, and met the resource need with short-term Delivered Supply resources delivered to its system by others. Figure IX-2 provides the Design Winter load duration curve for 2023/24, the fifth year of the planning period. The load duration curve in Figure IX-2 assumes the Portland Xpress, Atlantic Bridge and Westbrook Xpress projects are all in service. Visual inspection of this updated load duration curve shows the updated portfolio would be unable to meet Planning Load requirements approximately 35 days of the year, again with contributions being made from LNG.

Figure IX-2: Load Duration Curve, Design Winter 2023/24



In order to assess portfolio adequacy and the ability of incremental resource to contribute to portfolio adequacy, Northern models a Cold Snap Analysis. As mentioned, the cold snap analysis is embedded in the design year Sendout® modeling used to identify the incremental resource need. Figure IX-3 demonstrates the operation of the portfolio and the degree of incremental resource need required during the modeled cold snap for 2023/24. The chart also lists each supply modeled including the "Incremental Supply". Appendix 5 provides the cold snap analyses for the five years of the planning period.

Figure IX-3: Cold Snap Analysis, Design Winter 2019/20



	1/22/2024	1/23/2024	1/24/2024	1/25/2024	1/26/2024	1/27/2024	1/28/2024	1/29/2024	1/30/2024	1/31/2024
Incremental Supply	25,642	21,312	13,557	26,941	23,427	6,629	-	-	26,540	50,603
LNG	4,939	6,144	6,441	4,939	6,441	6,441	-	2,332	4,941	6,141
Union Dawn Storage	39,823	39,823	39,823	39,823	39,823	39,823	39,796	39,823	39,823	39,823
Tennessee Zone 0 and Zone L Pools	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
Tennessee Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
WXP Dawn Supply	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965
PXP Dawn Supply	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965
AB Ramapo Supply	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Iroquois Receipts	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462
Transco Zone 6, non-NY Supply	286	286	286	286	286	286	286	286	286	286
Leidy Hub Supply	965	965	965	965	965	965	965	965	965	965
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	59	59	59	59	59	59	59	59	59	59
Cold Snap Loads	123,686	120,560	113,102	124,985	122,972	106,174	93,077	95,436	124,585	149,848

D. Regulatory Considerations

Northern's 2019 IRP highlights the Company's efforts to comply with expectations of the Commissions that oversee the Company's procurement of supply resources, including the New Hampshire statutes under RSA 378:38.

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 by extension to provide supporting data and analysis that is adequate to allow decision makers in both states to understand and 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 new long-term contract decisions, Northern anticipates needing pre-approval of significant commitments and consistent treatment of new commitments in each jurisdiction, including findings that new long-term resource decisions are determined to promote the public interest, are the result of prudent utility management, and that Northern is granted approval to recover the costs associated with new long-term contracts.

Appendix 1, Supplemental Materials for the Demand Forecast Section

Appendix 2, Current Portfolio Capacity Path Diagrams

Appendix 3, Capacity Path Maps and Pipeline Maps

Appendix 4, Energy Efficiency Program Tables

Appendix 5, Supplemental Materials for the Preferred Portfolio Section

Appendix 6, New Hampshire RSA 378:37-40

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 2019/20 – 2023/24 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	November 2014 – March 2019	April 1, 2018 – March 31, 2019
Independent Variables Types	Economic, demographic, and weather data, indicator variables	Weather and date/seasonal-related data
Demand Data Detail	Six Customer Segments, plus Company Use	Design Day Throughput and Planning Load
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	2019/20 – 2023/24 Split Years	2019/20 – 2023/24 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 2019 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:

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

	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	Percent Factors 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.

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) Company Use, (2) Daily Throughput, and (3) Daily Planning Load.

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).

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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).

DG 19-126
Hearing Exhibit 2

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 12 using 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., 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

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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.

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.

DG 19-126
Hearing Exhibit 2

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

Variable Nomenclature

Variable	Description
POPULATION	Total Population
C	Constant
TREND	Linear Trend
WINTER_MONTHS	November - March
JAN	January
FEB	February
MAR	March
APR	April
MAY	May
JUN	June
JUL	July
AUG	August
SEP	September
OCT	October
NOV	November
DEC	December
BC_JAN	January Bill Cycle EDD
BC_FEB	February Bill Cycle EDD
BC_MAR	March Bill Cycle EDD
BC_APR	April Bill Cycle EDD
BC_MAY	May Bill Cycle EDD
BC_JUN	June Bill Cycle EDD
BC_JUL	July Bill Cycle EDD
BC_AUG	August Bill Cycle EDD
BC_SEP	September Bill Cycle EDD
BC_OCT	October Bill Cycle EDD
BC_NOV	November Bill Cycle EDD
BC_DEC	December Bill Cycle EDD
AR(1)	Autoregressive Term, Lag 1
AR(3)	Autoregressive Term, Lag 3
AR(2)	Autoregressive Term, Lag 2
AR(10)	Autoregressive Term, Lag 10
D_2018M5_F	Dummy Variable - May 2018 and Forward
D_2018M10_F	Dummy Variable - October 2018 and Forward
D_2017M11_F	Dummy Variable - November 2017 and Forward
D_2017M4_F	Dummy Variable - April 2017 and Forward
D_2015M11_F	Dummy Variable - November 2015 and Forward

DG 19-126
Hearing Exhibit 2

Residential Customer Segment – Customer Model

Dependent Variable: RES_CUST
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 05/22/19 Time: 08:24
Sample (adjusted): 2015M02 2019M03
Included observations: 50 after adjustments
Failure to improve likelihood (non-zero gradients) after 8 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
POPULATION*TREND	0.055928	0.001931	28.96862	0.0000
NOV	531.6085	54.28055	9.793721	0.0000
DEC	805.7598	52.63740	15.30774	0.0000
JAN	1050.213	53.56161	19.60757	0.0000
FEB	1047.806	51.48872	20.35021	0.0000
MAR	846.6899	52.30257	16.18830	0.0000
APR	467.1565	44.36342	10.53022	0.0000
OCT	294.1099	44.67046	6.583990	0.0000
C	20824.98	39.34829	529.2475	0.0000
D_2018M5_F*TREND	0.941578	0.650232	1.448065	0.1560
AR(1)	0.694912	0.148548	4.678020	0.0000
AR(3)	-0.253551	0.148677	-1.705375	0.0965
AR(2)	-0.596049	0.162219	-3.674341	0.0008

R-squared	0.987175	Mean dependent var	22486.78
Adjusted R-squared	0.983016	S.D. dependent var	648.6585
S.E. of regression	84.53482	Akaike info criterion	11.93110
Sum squared resid	264407.0	Schwarz criterion	12.42823
Log likelihood	-285.2775	Hannan-Quinn criter.	12.12041
F-statistic	237.3395	Durbin-Watson stat	2.018546
Prob(F-statistic)	0.000000		

Inverted AR Roots	.49-.80i	.49+.80i	-.29

Heteroskedasticity Test: White

F-statistic	0.551654	Prob. F(12,37)	0.8655
Obs*R-squared	7.588115	Prob. Chi-Square(12)	0.8164
Scaled explained SS	2.994248	Prob. Chi-Square(12)	0.9956

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/29/19 Time: 13:28
Sample: 2015M02 2019M03
Included observations: 50
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	10284.33	5696.919	1.805245	0.0792
GRADF_01^2	-3.89E-06	5.18E-06	-0.749706	0.4582
GRADF_02^2	803.4173	4436.586	0.181089	0.8573
GRADF_03^2	-1692.916	4133.328	-0.409577	0.6845
GRADF_04^2	-4226.651	4493.530	-0.940608	0.3530
GRADF_05^2	6242.958	3942.785	1.583388	0.1218
GRADF_06^2	-5948.131	3737.531	-1.591460	0.1200
GRADF_07^2	-3507.608	4027.451	-0.870925	0.3894
GRADF_08^2	-2928.661	4323.133	-0.677439	0.5023
GRADF_10^2	0.866053	1.267827	0.683100	0.4988
GRADF_11^2	-0.020302	0.053864	-0.376905	0.7084
GRADF_12^2	-0.049780	0.054466	-0.913954	0.3667
GRADF_13^2	0.021191	0.043517	0.486964	0.6292

R-squared	0.151762	Mean dependent var	5288.141
Adjusted R-squared	-0.123342	S.D. dependent var	6412.837
S.E. of regression	6796.826	Akaike info criterion	20.70519
Sum squared resid	1.71E+09	Schwarz criterion	21.20232
Log likelihood	-504.6299	Hannan-Quinn criter.	20.89450
F-statistic	0.551654	Durbin-Watson stat	1.371328
Prob(F-statistic)	0.865523		

obs	Actual	Fitted	Residual	Residual Plot
2015M02	22093.0	22281.7	-188.695	
2015M03	22142.0	22223.0	-80.9555	
2015M04	22024.0	22025.3	-1.27245	
2015M05	21700.0	21605.4	94.6224	
2015M06	21471.0	21519.7	-48.7076	
2015M07	21317.0	21243.2	73.8420	
2015M08	21218.0	21270.6	-52.6399	
2015M09	21441.0	21386.0	54.9767	
2015M10	22061.0	21967.5	93.4671	
2015M11	22302.0	22358.1	-56.0599	
2015M12	22418.0	22418.3	-0.29625	
2016M01	22476.0	22502.6	-26.5744	
2016M02	22502.0	22498.5	3.51822	
2016M03	22527.0	22502.8	24.1546	
2016M04	22435.0	22345.3	89.6612	
2016M05	22040.0	21970.6	69.3907	
2016M06	21770.0	21826.7	-56.6655	
2016M07	21685.0	21557.8	127.232	
2016M08	21618.0	21676.0	-58.0390	
2016M09	21908.0	21783.3	124.670	
2016M10	22379.0	22375.2	3.77325	
2016M11	22628.0	22614.6	13.4439	
2016M12	22813.0	22752.6	60.4331	
2017M01	22865.0	22918.2	-53.2194	
2017M02	22891.0	22867.2	23.7958	
2017M03	22888.0	22858.0	29.9537	
2017M04	22706.0	22683.0	22.9623	
2017M05	22263.0	22262.8	0.16786	
2017M06	22064.0	22146.7	-82.6510	
2017M07	22073.0	21978.9	94.0748	
2017M08	22046.0	22132.7	-86.7246	
2017M09	22156.0	22194.1	-38.1355	
2017M10	22539.0	22613.6	-74.6095	
2017M11	23008.0	22889.3	118.697	
2017M12	23144.0	23278.6	-134.628	
2018M01	23223.0	23301.8	-78.7594	
2018M02	23234.0	23243.3	-9.26115	
2018M03	23246.0	23220.4	25.6246	
2018M04	23099.0	23058.2	40.8028	
2018M05	22665.0	22709.3	-44.3200	
2018M06	22527.0	22540.0	-12.9758	
2018M07	22339.0	22431.9	-92.9446	
2018M08	22338.0	22424.4	-86.4479	
2018M09	22513.0	22607.3	-94.3019	
2018M10	23193.0	23107.8	85.1726	
2018M11	23511.0	23545.9	-34.8954	
2018M12	23636.0	23638.2	-2.16574	
2019M01	23696.0	23669.7	26.2985	
2019M02	23753.0	23644.2	108.828	
2019M03	23755.0	23668.6	86.3816	

Date: 06/29/19 Time: 13:28
Sample: 2014M11 2042M10
Included observations: 50
Q-statistic probabilities adjusted for 3 ARMA terms

<table>
<tr><th>Autocorrelation</th><th>Partial Correlation</th><th></th><th>AC</th><th>PAC</th><th>Q-Stat</th><th>Prob*</th></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>1</td><td>-0.091</td><td>-0.091</td><td>0.4366</td><td></td></tr>
<tr><td>. |*. |</td><td>. |*. |</td><td>2</td><td>0.143</td><td>0.136</td><td>1.5388</td><td></td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>3</td><td>-0.099</td><td>-0.077</td><td>2.0780</td><td></td></tr>
<tr><td>. |*. |</td><td>. |*. |</td><td>4</td><td>0.121</td><td>0.092</td><td>2.9101</td><td>0.088</td></tr>
<tr><td>. | . |</td><td>. |*. |</td><td>5</td><td>0.039</td><td>0.080</td><td>2.9978</td><td>0.223</td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>6</td><td>-0.115</td><td>-0.149</td><td>3.7817</td><td>0.286</td></tr>
<tr><td>. |*. |</td><td>. |*. |</td><td>7</td><td>0.102</td><td>0.096</td><td>4.4160</td><td>0.353</td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>8</td><td>-0.125</td><td>-0.089</td><td>5.3831</td><td>0.371</td></tr>
<tr><td>. | . |</td><td>. | . |</td><td>9</td><td>0.060</td><td>-0.014</td><td>5.6125</td><td>0.468</td></tr>
<tr><td>. | . |</td><td>. | . |</td><td>10</td><td>-0.044</td><td>0.037</td><td>5.7382</td><td>0.571</td></tr>
<tr><td>. |*. |</td><td>. |*. |</td><td>11</td><td>0.140</td><td>0.107</td><td>7.0401</td><td>0.532</td></tr>
<tr><td>. |*. |</td><td>. |*. |</td><td>12</td><td>0.143</td><td>0.178</td><td>8.4459</td><td>0.490</td></tr>
</table>

DG 19-126
Hearing Exhibit 2

Residential Customer Segment - Use Per Customer Model

Dependent Variable: RES_UPC
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 06/03/19 Time: 10:56
Sample (adjusted): 2014M12 2019M03
Included observations: 52 after adjustments
Convergence achieved after 5 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BC_APR	0.073469	0.001966	37.36938	0.0000
BC_DEC	0.081662	0.001852	44.09978	0.0000
BC_FEB	0.086215	0.001411	61.09626	0.0000
BC_JAN	0.088331	0.001437	61.48526	0.0000
BC_JUN	0.042951	0.007115	6.036700	0.0000
BC_MAR	0.082221	0.001612	51.00879	0.0000
BC_NOV	0.058802	0.003032	19.39082	0.0000
BC_MAY	0.057161	0.003467	16.48913	0.0000
BC_OCT	0.034941	0.005566	6.278053	0.0000
C	13.02477	1.071460	12.15610	0.0000
D_2017M11_F*TREND*(WINTER_MONTHS)	0.062000	0.028704	2.159996	0.0368
AR(1)	0.395684	0.145748	2.714860	0.0097

R-squared	0.997059	Mean dependent var	63.16964
Adjusted R-squared	0.996250	S.D. dependent var	44.95802
S.E. of regression	2.753255	Akaike info criterion	5.062619
Sum squared resid	303.2165	Schwarz criterion	5.512906
Log likelihood	-119.6281	Hannan-Quinn criter.	5.235248
F-statistic	1232.593	Durbin-Watson stat	1.976715
Prob(F-statistic)	0.000000		

Inverted AR Roots	.40

DG 19-126
Hearing Exhibit 2

Heteroskedasticity Test: White

F-statistic	2.843943	Prob. F(11,40)	0.0076
Obs*R-squared	22.82069	Prob. Chi-Square(11)	0.0187
Scaled explained SS	14.15032	Prob. Chi-Square(11)	0.2248

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/29/19 Time: 13:30
Sample: 2014M12 2019M03
Included observations: 52
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2.502432	2.001885	1.250038	0.2185
GRADF_01^2	1.61E-06	4.94E-06	0.325428	0.7466
GRADF_02^2	9.14E-06	4.59E-06	1.988944	0.0536
GRADF_03^2	5.46E-06	2.28E-06	2.388777	0.0217
GRADF_04^2	1.44E-06	2.37E-06	0.605842	0.5480
GRADF_05^2	1.07E-06	9.02E-05	0.011840	0.9906
GRADF_06^2	8.63E-07	3.14E-06	0.274885	0.7848
GRADF_07^2	2.57E-05	1.25E-05	2.064392	0.0455
GRADF_08^2	3.10E-05	1.63E-05	1.902620	0.0643
GRADF_09^2	-1.85E-05	5.16E-05	-0.357550	0.7226
GRADF_11^2	0.003046	0.001841	1.654334	0.1059
GRADF_12^2	-0.235715	0.133732	-1.762596	0.0856

R-squared	0.438859	Mean dependent var	5.831087
Adjusted R-squared	0.284546	S.D. dependent var	8.523994
S.E. of regression	7.209981	Akaike info criterion	6.987984
Sum squared resid	2079.353	Schwarz criterion	7.438271
Log likelihood	-169.6876	Hannan-Quinn criter.	7.160613
F-statistic	2.843943	Durbin-Watson stat	1.741024
Prob(F-statistic)	0.007637		

obs	Actual	Fitted	Residual	Residual Plot
2014M12	96.0902	92.6516	3.43861	| . | . * |
2015M01	125.489	123.856	1.63285	| . | *. |
2015M02	150.463	145.975	4.48817	| . | . * |
2015M03	121.961	123.929	-1.96880	| .* | . |
2015M04	83.0915	80.3764	2.71505	| . | * |
2015M05	34.7049	38.5001	-3.79510	| * . | . |
2015M06	21.8456	20.1717	1.67390	| . | *. |
2015M07	15.1626	13.2690	1.89355	| . | *. |
2015M08	13.0542	13.8707	-0.81645	| . *| . |
2015M09	13.3930	13.0364	0.35656	| . |* . |
2015M10	24.1269	23.8625	0.26441	| . * . |
2015M11	44.9452	47.5864	-2.64126	| * | . |
2015M12	76.4254	79.3332	-2.90789	| *. | . |
2016M01	104.881	107.856	-2.97436	| *. | . |
2016M02	116.145	113.403	2.74122	| . | * |
2016M03	95.8664	97.9261	-2.05974	| .* | . |
2016M04	69.4006	72.6041	-3.20352	| *. | . |
2016M05	41.7791	43.2754	-1.49631	| . * | . |
2016M06	19.8685	19.8158	0.05268	| . * . |
2016M07	13.2516	12.5717	0.67993	| . |* . |
2016M08	13.7890	13.1145	0.67444	| . |* . |
2016M09	13.3729	13.3271	0.04576	| . * . |
2016M10	22.2427	23.0159	-0.77325	| . *| . |
2016M11	50.9032	49.1720	1.73119	| . | *. |
2016M12	89.3152	94.5372	-5.22202	| * . | . |
2017M01	116.333	117.895	-1.56148	| .* | . |
2017M02	112.509	113.845	-1.33610	| . * | . |
2017M03	103.927	102.983	0.94345	| . | * . |
2017M04	81.0985	80.9376	0.16097	| . * . |
2017M05	46.4985	41.7650	4.73349	| . | . * |
2017M06	27.0983	26.3835	0.71474	| . |* . |
2017M07	15.4271	14.0558	1.37132	| . | * . |
2017M08	13.6611	13.9753	-0.31425	| . *| . |
2017M09	14.5872	13.2766	1.31065	| . | * . |
2017M10	17.4795	19.3734	-1.89388	| .* | . |
2017M11	40.3636	46.9585	-6.59492	|* . | . |
2017M12	100.280	98.4072	1.87286	| . | *. |
2018M01	155.002	152.200	2.80150	| . | * |
2018M02	116.518	120.841	-4.32274	| * . | . |
2018M03	96.4288	95.0643	1.36457	| . | * . |
2018M04	82.5611	82.3935	0.16762	| . * . |
2018M05	42.0579	41.2769	0.78095	| . |* . |
2018M06	21.1080	21.7376	-0.62961	| . *| . |
2018M07	13.6865	12.9092	0.77736	| . |* . |
2018M08	12.7355	13.2866	-0.55114	| . *| . |
2018M09	12.7095	12.9103	-0.20080	| . * . |
2018M10	25.1973	23.6270	1.57039	| . | *. |
2018M11	67.0937	62.2450	4.84867	| . | . * |
2018M12	110.453	108.923	1.52937	| . | * . |
2019M01	125.522	127.386	-1.86355	| .* | . |
2019M02	128.634	131.065	-2.43135	| * | . |
2019M03	114.285	112.063	2.22229	| . | * |

Date: 06/29/19 Time: 13:30
Sample: 2014M11 2042M10
Included observations: 52
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	-0.016	-0.016	0.0141	
. | . |	. | . |	2	-0.017	-0.017	0.0294	0.864
. | . |	. | . |	3	-0.044	-0.044	0.1397	0.933
. | . |	. | . |	4	0.073	0.072	0.4533	0.929
.*| . |	.*| . |	5	-0.156	-0.157	1.9117	0.752
. | . |	. | . |	6	-0.056	-0.060	2.1045	0.835
. | . |	. | . |	7	0.022	0.022	2.1349	0.907
. |*. |	. |*. |	8	0.093	0.074	2.6838	0.913
.*| . |	.*| . |	9	-0.118	-0.103	3.5970	0.892
. |*. |	. |*. |	10	0.104	0.095	4.3158	0.889
. | . |	. | . |	11	0.027	0.012	4.3674	0.929
		12	-0.114	-0.136	5.2798	0.917

LLF Customer Segment – Customer Model

Dependent Variable: LLF_CUST
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 05/22/19 Time: 08:31
Sample (adjusted): 2015M01 2019M03
Included observations: 51 after adjustments
Failure to improve likelihood (non-zero gradients) after 12 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
POPULATION*TREND	0.006144	0.001720	3.572086	0.0010
NOV	223.0248	24.86837	8.968214	0.0000
DEC	305.2700	25.70412	11.87631	0.0000
JAN	371.1218	24.82017	14.95242	0.0000
FEB	372.1605	24.40064	15.25208	0.0000
MAR	312.7095	23.43512	13.34363	0.0000
APR	147.2228	17.10567	8.606668	0.0000
OCT	129.4130	17.51074	7.390492	0.0000
C	7561.640	26.55650	284.7378	0.0000
TREND*D_2017M4_F	2.218127	0.505190	4.390679	0.0001
AR(2)	-0.717352	0.110874	-6.469996	0.0000
AR(1)	0.908439	0.114157	7.957816	0.0000

R-squared	0.977209	Mean dependent var	7913.176
Adjusted R-squared	0.970781	S.D. dependent var	191.3015
S.E. of regression	32.70004	Akaike info criterion	10.01495
Sum squared resid	41702.42	Schwarz criterion	10.46950
Log likelihood	-243.3813	Hannan-Quinn criter.	10.18865
F-statistic	152.0216	Durbin-Watson stat	1.845084
Prob(F-statistic)	0.000000		

Inverted AR Roots	.45+.71i	.45-.71i

Heteroskedasticity Test: White

F-statistic	2.062338	Prob. F(11,39)	0.0480
Obs*R-squared	18.75591	Prob. Chi-Square(11)	0.0656
Scaled explained SS	10.43882	Prob. Chi-Square(11)	0.4914

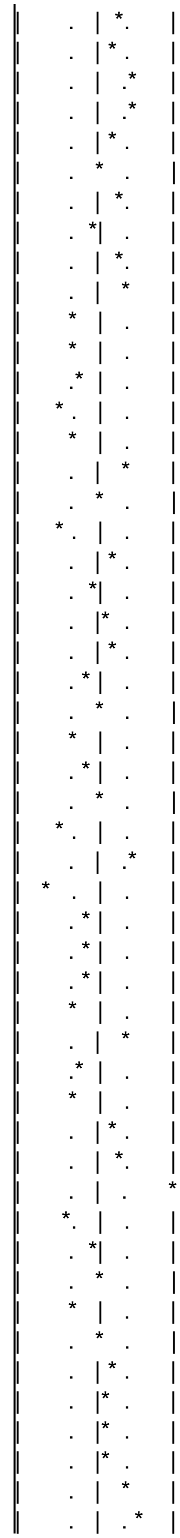
Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/29/19 Time: 13:32
Sample: 2015M01 2019M03
Included observations: 51
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	599.9758	452.4628	1.326022	0.1925
GRADF_01^2	-1.20E-06	2.03E-06	-0.593037	0.5566
GRADF_02^2	64.25626	676.8995	0.094927	0.9249
GRADF_03^2	11.49108	676.7122	0.016981	0.9865
GRADF_04^2	188.5890	664.9015	0.283635	0.7782
GRADF_05^2	437.7985	619.7262	0.706439	0.4841
GRADF_06^2	147.9268	614.3163	0.240799	0.8110
GRADF_07^2	1771.584	577.8547	3.065794	0.0039
GRADF_08^2	177.3693	596.8645	0.297168	0.7679
GRADF_10^2	0.446837	0.446658	1.000400	0.3233
GRADF_11^2	-0.074220	0.049862	-1.488495	0.1447
GRADF_12^2	-0.054460	0.052224	-1.042828	0.3034

R-squared	0.367763	Mean dependent var	817.6945
Adjusted R-squared	0.189440	S.D. dependent var	1139.379
S.E. of regression	1025.796	Akaike info criterion	16.90665
Sum squared resid	41038034	Schwarz criterion	17.36120
Log likelihood	-419.1196	Hannan-Quinn criter.	17.08035
F-statistic	2.062338	Durbin-Watson stat	2.019996
Prob(F-statistic)	0.047955		

obs	Actual	Fitted	Residual
2015M01	7966.00	7942.58	23.4201
2015M02	7964.00	7950.91	13.0915
2015M03	7956.00	7920.63	35.3730
2015M04	7847.00	7806.68	40.3224
2015M05	7693.00	7676.50	16.4990
2015M06	7635.00	7632.45	2.54942
2015M07	7611.00	7587.26	23.7403
2015M08	7605.00	7609.70	-4.70471
2015M09	7646.00	7624.11	21.8873
2015M10	7830.00	7797.72	32.2768
2015M11	7885.00	7914.16	-29.1586
2015M12	7891.00	7924.82	-33.8215
2016M01	7928.00	7951.76	-23.7581
2016M02	7939.00	7983.94	-44.9388
2016M03	7926.00	7956.89	-30.8892
2016M04	7857.00	7829.12	27.8846
2016M05	7740.00	7738.89	1.11321
2016M06	7655.00	7699.79	-44.7940
2016M07	7622.00	7603.56	18.4373
2016M08	7633.00	7637.23	-4.23118
2016M09	7682.00	7673.57	8.43016
2016M10	7856.00	7842.28	13.7166
2016M11	7930.00	7943.93	-13.9259
2016M12	7979.00	7979.05	-0.05263
2017M01	7999.00	8031.45	-32.4549
2017M02	8002.00	8017.38	-15.3768
2017M03	7998.00	7995.29	2.71473
2017M04	7925.00	7974.62	-49.6220
2017M05	7833.00	7791.92	41.0826
2017M06	7783.00	7845.47	-62.4659
2017M07	7753.00	7764.92	-11.9219
2017M08	7764.00	7778.03	-14.0289
2017M09	7798.00	7814.04	-16.0374
2017M10	7939.00	7970.94	-31.9439
2017M11	8089.00	8055.19	33.8084
2017M12	8160.00	8184.85	-24.8523
2018M01	8172.00	8204.54	-32.5429
2018M02	8182.00	8169.23	12.7656
2018M03	8184.00	8161.06	22.9359
2018M04	8131.00	8049.49	81.5147
2018M05	7930.00	7964.88	-34.8820
2018M06	7835.00	7839.85	-4.84582
2018M07	7796.00	7796.65	-0.64623
2018M08	7804.00	7833.87	-29.8747
2018M09	7876.00	7873.64	2.35840
2018M10	8085.00	8067.25	17.7530
2018M11	8192.00	8186.02	5.97540
2018M12	8238.00	8227.87	10.1332
2019M01	8264.00	8255.71	8.28874
2019M02	8281.00	8251.07	29.9268
2019M03	8283.00	8239.23	43.7708

Residual Plot



Date: 06/29/19 Time: 13:33
Sample: 2014M11 2042M10
Included observations: 51
Q-statistic probabilities adjusted for 2 ARMA terms

<table>
<tr><th>Autocorrelation</th><th>Partial Correlation</th><th></th><th>AC</th><th>PAC</th><th>Q-Stat</th><th>Prob*</th></tr>
<tr><td>. | . |</td><td>. | . |</td><td>1</td><td>0.048</td><td>0.048</td><td>0.1241</td><td></td></tr>
<tr><td>. |*. |</td><td>. |*. |</td><td>2</td><td>0.132</td><td>0.130</td><td>1.0846</td><td></td></tr>
<tr><td>. |*. |</td><td>. |*. |</td><td>3</td><td>0.149</td><td>0.140</td><td>2.3394</td><td>0.126</td></tr>
<tr><td>. | . |</td><td>.*| . |</td><td>4</td><td>-0.041</td><td>-0.070</td><td>2.4369</td><td>0.296</td></tr>
<tr><td>. | . |</td><td>. | . |</td><td>5</td><td>0.062</td><td>0.029</td><td>2.6618</td><td>0.447</td></tr>
<tr><td>. | . |</td><td>. | . |</td><td>6</td><td>0.067</td><td>0.061</td><td>2.9343</td><td>0.569</td></tr>
<tr><td>. | . |</td><td>. | . |</td><td>7</td><td>0.008</td><td>0.008</td><td>2.9381</td><td>0.710</td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>8</td><td>-0.086</td><td>-0.125</td><td>3.4053</td><td>0.757</td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>9</td><td>-0.143</td><td>-0.160</td><td>4.7206</td><td>0.694</td></tr>
<tr><td>.*| . |</td><td>. | . |</td><td>10</td><td>-0.091</td><td>-0.057</td><td>5.2672</td><td>0.729</td></tr>
<tr><td>. |*. |</td><td>. |** |</td><td>11</td><td>0.130</td><td>0.217</td><td>6.4118</td><td>0.698</td></tr>
<tr><td>. | . |</td><td>. | . |</td><td>12</td><td>-0.035</td><td>0.006</td><td>6.4952</td><td>0.772</td></tr>
</table>

*

LLF Customer Segment - Use Per Customer Model

Dependent Variable: LLF_UPC
Method: Least Squares
Date: 06/03/19 Time: 11:00
Sample (adjusted): 2014M11 2019M03
Included observations: 53 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BC_APR	0.641723	0.018224	35.21323	0.0000
BC_DEC	0.803944	0.015215	52.83993	0.0000
BC_FEB	0.771301	0.011657	66.16686	0.0000
BC_JAN	0.822017	0.011833	69.46884	0.0000
BC_MAR	0.774325	0.013381	57.86731	0.0000
BC_MAY	0.443825	0.033107	13.40595	0.0000
BC_NOV	0.687676	0.024155	28.46958	0.0000
BC_OCT	0.460524	0.060512	7.610428	0.0000
C	248.2750	10.41163	23.84594	0.0000
TREND*D_2015M11_F	0.715481	0.392374	1.823466	0.0754
D_2015M11_F	-53.88938	20.16721	-2.672129	0.0107

R-squared	0.995878	Mean dependent var	688.8328
Adjusted R-squared	0.994897	S.D. dependent var	413.0051
S.E. of regression	29.50319	Akaike info criterion	9.789346
Sum squared resid	36558.41	Schwarz criterion	10.19827
Log likelihood	-248.4177	Hannan-Quinn criter.	9.946600
F-statistic	1014.804	Durbin-Watson stat	1.745970
Prob(F-statistic)	0.000000		

DG 19-126
Hearing Exhibit 2

Heteroskedasticity Test: White

F-statistic	2.837412	Prob. F(10,42)	0.0087
Obs*R-squared	21.36905	Prob. Chi-Square(10)	0.0187
Scaled explained SS	9.899299	Prob. Chi-Square(10)	0.4494

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/29/19 Time: 13:34
Sample: 2014M11 2019M03
Included observations: 53

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1063.565	255.2544	4.166687	0.0002
BC_APR^2	-0.000762	0.000491	-1.551830	0.1282
BC_DEC^2	-3.07E-06	0.000370	-0.008299	0.9934
BC_FEB^2	0.000294	0.000215	1.365447	0.1794
BC_JAN^2	0.000803	0.000220	3.649596	0.0007
BC_MAR^2	-5.14E-05	0.000283	-0.181267	0.8570
BC_MAY^2	-0.000363	0.001601	-0.226563	0.8219
BC_NOV^2	-0.000755	0.000912	-0.827429	0.4127
BC_OCT^2	-0.003059	0.005090	-0.600966	0.5511
TREND*D_2015M11_F^2	-1.999032	9.717284	-0.205719	0.8380
D_2015M11_F^2	-476.1459	500.2779	-0.951763	0.3467

R-squared	0.403190	Mean dependent var	689.7813
Adjusted R-squared	0.261092	S.D. dependent var	845.8607
S.E. of regression	727.0998	Akaike info criterion	16.19848
Sum squared resid	22204312	Schwarz criterion	16.60741
Log likelihood	-418.2596	Hannan-Quinn criter.	16.35573
F-statistic	2.837412	Durbin-Watson stat	1.702814
Prob(F-statistic)	0.008707		

obs	Actual	Fitted	Residual	Residual Plot
2014M11	666.910	651.941	14.9688	| . | * . |
2014M12	1048.26	1024.88	23.3723	| . | *. |
2015M01	1324.99	1264.29	60.7058	| . | . *
2015M02	1471.87	1426.05	45.8156	| . | . * |
2015M03	1237.68	1271.16	-33.4775	| *. | . |
2015M04	841.994	835.451	6.54305	| . |* . |
2015M05	404.494	437.344	-32.8505	| *. | . |
2015M06	280.217	248.275	31.9416	| . | .* |
2015M07	223.782	248.275	-24.4926	| .* | . |
2015M08	212.978	248.275	-35.2971	| *. | . |
2015M09	215.720	248.275	-32.5548	| *. | . |
2015M10	364.521	389.195	-24.6747	| .* | . |
2015M11	587.087	614.563	-27.4760	| * | . |
2015M12	861.601	875.438	-13.8369	| . * | . |
2016M01	1125.41	1110.52	14.8849	| . | * . |
2016M02	1154.92	1128.41	26.5138	| . | * |
2016M03	998.257	1011.14	-12.8836	| . * | . |
2016M04	743.319	742.063	1.25626	| . * . |
2016M05	465.086	463.332	1.75352	| . * . |
2016M06	271.370	217.281	54.0894	| . | . * |
2016M07	204.488	217.996	-13.5089	| . * | . |
2016M08	215.194	218.712	-3.51808	| . *| . |
2016M09	217.074	219.427	-2.35294	| . * . |
2016M10	356.875	350.011	6.86477	| . |* . |
2016M11	643.008	646.530	-3.52160	| . *| . |
2016M12	987.408	1018.28	-30.8742	| * | . |
2017M01	1190.38	1215.29	-24.9041	| .* | . |
2017M02	1109.73	1137.00	-27.2634	| * | . |
2017M03	1104.88	1080.90	23.9840	| . | *. |
2017M04	814.290	818.029	-3.73925	| . *| . |
2017M05	482.059	447.951	34.1077	| . | .* |
2017M06	271.623	225.867	45.7562	| . | . * |
2017M07	243.992	226.582	17.4095	| . | * . |
2017M08	211.029	227.298	-16.2691	| . * | . |
2017M09	221.950	228.013	-6.06351	| . *| . |
2017M10	292.198	304.255	-12.0566	| . * | . |
2017M11	588.446	596.663	-8.21737	| . *| . |
2017M12	1100.40	1067.87	32.5287	| . | .* |
2018M01	1441.03	1500.07	-59.0402	|* . | . |
2018M02	1118.02	1158.69	-40.6775	| * . | . |
2018M03	1016.32	986.499	29.8192	| . | * |
2018M04	835.038	838.808	-3.76930	| . *| . |
2018M05	444.221	452.543	-8.32192	| . *| . |
2018M06	269.214	234.453	34.7612	| . | .* |
2018M07	219.284	235.168	-15.8838	| . * | . |
2018M08	221.040	235.883	-14.8436	| . * | . |
2018M09	221.488	236.599	-15.1112	| . * | . |
2018M10	403.424	378.695	24.7292	| . | *. |
2018M11	780.885	762.727	18.1582	| . | * . |
2018M12	1110.74	1123.89	-13.1468	| . * | . |
2019M01	1278.12	1253.83	24.2872	| . | *. |
2019M02	1246.92	1262.15	-15.2285	| . * | . |
2019M03	1146.91	1145.30	1.60432	| . * . |

Date: 06/29/19 Time: 13:34
Sample: 2014M11 2042M10
Included observations: 53

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
. |*. |	. |*. |	1	0.124	0.124	0.8608	0.354
. | . |	. | . |	2	0.007	-0.008	0.8637	0.649
. | . |	. | . |	3	-0.017	-0.017	0.8800	0.830
. | . |	. | . |	4	-0.036	-0.033	0.9582	0.916
.*| . |	. | . |	5	-0.071	-0.063	1.2607	0.939
.*| . |	.*| . |	6	-0.117	-0.103	2.1036	0.910
.*| . |	.*| . |	7	-0.146	-0.125	3.4513	0.840
**| . |	**| . |	8	-0.245	-0.229	7.3309	0.501
.*| . |	.*| . |	9	-0.155	-0.135	8.9210	0.445
.*| . |	.*| . |	10	-0.169	-0.199	10.862	0.368
. | . |	.*| . |	11	-0.059	-0.110	11.107	0.434
. |*. |	. |*. |	12	0.200	0.143	13.954	0.304

HLF Customer Segment – Customer Model

Dependent Variable: HLF_CUST
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 05/16/19 Time: 09:56
Sample (adjusted): 2015M05 2019M03
Included observations: 47 after adjustments
Convergence achieved after 7 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1053.165	30.70586	34.29851	0.0000
D_2018M5_F	71.77144	5.128966	13.99335	0.0000
TREND	1.000842	0.545313	1.835354	0.0735
AR(1)	0.431036	0.138192	3.119109	0.0033
AR(2)	0.432551	0.136777	3.162459	0.0029

R-squared	0.985184	Mean dependent var	1119.170
Adjusted R-squared	0.983773	S.D. dependent var	41.16051
S.E. of regression	5.243210	Akaike info criterion	6.252033
Sum squared resid	1154.632	Schwarz criterion	6.448857
Log likelihood	-141.9228	Hannan-Quinn criter.	6.326099
F-statistic	698.2041	Durbin-Watson stat	1.950791
Prob(F-statistic)	0.000000		

Inverted AR Roots	.91	-.48

Heteroskedasticity Test: White

F-statistic	0.752532	Prob. F(4,42)	0.5620
Obs*R-squared	3.143204	Prob. Chi-Square(4)	0.5342
Scaled explained SS	6.792122	Prob. Chi-Square(4)	0.1473

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/29/19 Time: 13:36
Sample: 2015M05 2019M03
Included observations: 47
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	60.64721	29.06742	2.086433	0.0430
GRADF_02^2	47.22884	58.13769	0.812362	0.4212
GRADF_03^2	-0.540434	0.432050	-1.250860	0.2179
GRADF_04^2	0.035603	0.061230	0.581464	0.5640
GRADF_05^2	-0.073691	0.058299	-1.264008	0.2132

R-squared	0.066877	Mean dependent var	24.56665
Adjusted R-squared	-0.021992	S.D. dependent var	57.76915
S.E. of regression	58.40093	Akaike info criterion	11.07283
Sum squared resid	143248.1	Schwarz criterion	11.26965
Log likelihood	-255.2115	Hannan-Quinn criter.	11.14689
F-statistic	0.752532	Durbin-Watson stat	1.723351
Prob(F-statistic)	0.561990		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2015M05</td><td>1103.00</td><td>1100.52</td><td>2.47581</td><td>| . |* . |</td></tr>
<tr><td>2015M06</td><td>1105.00</td><td>1100.66</td><td>4.33776</td><td>| . | *. |</td></tr>
<tr><td>2015M07</td><td>1101.00</td><td>1101.23</td><td>-0.22829</td><td>| . * . |</td></tr>
<tr><td>2015M08</td><td>1104.00</td><td>1100.51</td><td>3.49423</td><td>| . | *. |</td></tr>
<tr><td>2015M09</td><td>1098.00</td><td>1100.21</td><td>-2.20521</td><td>| . *| . |</td></tr>
<tr><td>2015M10</td><td>1105.00</td><td>1099.05</td><td>5.94683</td><td>| . | * |</td></tr>
<tr><td>2015M11</td><td>1101.00</td><td>1099.61</td><td>1.38835</td><td>| . |* . |</td></tr>
<tr><td>2015M12</td><td>1100.00</td><td>1101.05</td><td>-1.05189</td><td>| . *| . |</td></tr>
<tr><td>2016M01</td><td>1104.00</td><td>1099.03</td><td>4.97282</td><td>| . | * |</td></tr>
<tr><td>2016M02</td><td>1092.00</td><td>1100.46</td><td>-8.45530</td><td>| * . | . |</td></tr>
<tr><td>2016M03</td><td>1094.00</td><td>1097.15</td><td>-3.14960</td><td>| .* | . |</td></tr>
<tr><td>2016M04</td><td>1087.00</td><td>1092.96</td><td>-5.95759</td><td>| * | . |</td></tr>
<tr><td>2016M05</td><td>1088.00</td><td>1090.94</td><td>-2.94197</td><td>| .* | . |</td></tr>
<tr><td>2016M06</td><td>1085.00</td><td>1088.48</td><td>-3.48168</td><td>| .* | . |</td></tr>
<tr><td>2016M07</td><td>1082.00</td><td>1087.76</td><td>-5.75765</td><td>| * | . |</td></tr>
<tr><td>2016M08</td><td>1066.00</td><td>1085.30</td><td>-19.3034</td><td>|* . | . |</td></tr>
<tr><td>2016M09</td><td>1087.00</td><td>1077.25</td><td>9.75428</td><td>| . | . * |</td></tr>
<tr><td>2016M10</td><td>1081.00</td><td>1079.51</td><td>1.48681</td><td>| . |* . |</td></tr>
<tr><td>2016M11</td><td>1090.00</td><td>1086.15</td><td>3.85293</td><td>| . | *. |</td></tr>
<tr><td>2016M12</td><td>1089.00</td><td>1087.57</td><td>1.43238</td><td>| . |* . |</td></tr>
<tr><td>2017M01</td><td>1092.00</td><td>1091.17</td><td>0.83394</td><td>| . * . |</td></tr>
<tr><td>2017M02</td><td>1093.00</td><td>1092.16</td><td>0.83685</td><td>| . * . |</td></tr>
<tr><td>2017M03</td><td>1098.00</td><td>1094.03</td><td>3.97163</td><td>| . | *. |</td></tr>
<tr><td>2017M04</td><td>1096.00</td><td>1096.75</td><td>-0.75262</td><td>| . * . |</td></tr>
<tr><td>2017M05</td><td>1095.00</td><td>1098.19</td><td>-3.18983</td><td>| .* | . |</td></tr>
<tr><td>2017M06</td><td>1099.00</td><td>1097.03</td><td>1.96978</td><td>| . |* . |</td></tr>
<tr><td>2017M07</td><td>1101.00</td><td>1098.46</td><td>2.54165</td><td>| . |* . |</td></tr>
<tr><td>2017M08</td><td>1101.00</td><td>1101.19</td><td>-0.18715</td><td>| . * . |</td></tr>
<tr><td>2017M09</td><td>1104.00</td><td>1102.19</td><td>1.81122</td><td>| . |* . |</td></tr>
<tr><td>2017M10</td><td>1104.00</td><td>1103.62</td><td>0.38159</td><td>| . * . |</td></tr>
<tr><td>2017M11</td><td>1107.00</td><td>1105.05</td><td>1.94740</td><td>| . |* . |</td></tr>
<tr><td>2017M12</td><td>1107.00</td><td>1106.48</td><td>0.51777</td><td>| . * . |</td></tr>
<tr><td>2018M01</td><td>1107.00</td><td>1107.92</td><td>-0.91641</td><td>| . *| . |</td></tr>
<tr><td>2018M02</td><td>1107.00</td><td>1108.05</td><td>-1.05294</td><td>| . *| . |</td></tr>
<tr><td>2018M03</td><td>1113.00</td><td>1108.19</td><td>4.81053</td><td>| . | * |</td></tr>
<tr><td>2018M04</td><td>1113.00</td><td>1110.91</td><td>2.08779</td><td>| . |* . |</td></tr>
<tr><td>2018M05</td><td>1180.00</td><td>1185.42</td><td>-5.41548</td><td>| * | . |</td></tr>
<tr><td>2018M06</td><td>1195.00</td><td>1183.50</td><td>11.5047</td><td>| . | . * |</td></tr>
<tr><td>2018M07</td><td>1194.00</td><td>1188.03</td><td>5.96647</td><td>| . | * |</td></tr>
<tr><td>2018M08</td><td>1190.00</td><td>1194.23</td><td>-4.22728</td><td>| .* | . |</td></tr>
<tr><td>2018M09</td><td>1192.00</td><td>1192.21</td><td>-0.20711</td><td>| . * . |</td></tr>
<tr><td>2018M10</td><td>1195.00</td><td>1191.48</td><td>3.52449</td><td>| . | *. |</td></tr>
<tr><td>2018M11</td><td>1194.00</td><td>1193.77</td><td>0.22975</td><td>| . * . |</td></tr>
<tr><td>2018M12</td><td>1197.00</td><td>1194.77</td><td>2.22661</td><td>| . |* . |</td></tr>
<tr><td>2019M01</td><td>1190.00</td><td>1195.77</td><td>-5.77048</td><td>| * | . |</td></tr>
<tr><td>2019M02</td><td>1189.00</td><td>1194.19</td><td>-5.18741</td><td>| * | . |</td></tr>
<tr><td>2019M03</td><td>1186.00</td><td>1190.87</td><td>-4.86505</td><td>| * | . |</td></tr>
</table>

Date: 06/29/19 Time: 13:37
Sample: 2014M11 2042M10
Included observations: 47
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	0.012	0.012	0.0069	
. | . |	. | . |	2	0.047	0.046	0.1177	
. |*. |	. |*. |	3	0.102	0.102	0.6674	0.414
. |*. |	. |*. |	4	0.078	0.075	0.9958	0.608
. | . |	. | . |	5	0.005	-0.005	0.9974	0.802
. | . |	. | . |	6	0.043	0.027	1.1021	0.894
**| . |	**| . |	7	-0.290	-0.311	5.9349	0.313
.*| . |	.*| . |	8	-0.080	-0.098	6.3166	0.389
. | . |	. | . |	9	-0.053	-0.043	6.4878	0.484
.*| . |	.*| . |	10	-0.143	-0.088	7.7531	0.458
. | . |	. | . |	11	-0.039	0.040	7.8529	0.549
. | . |	. | . |	12	-0.025	0.019	7.8933	0.639

HLF Customer Segment - Use Per Customer Model

Dependent Variable: HLF_UPC
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 06/03/19 Time: 11:04
Sample (adjusted): 2016M03 2019M03
Included observations: 37 after adjustments
Convergence achieved after 6 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BC_APR	0.176348	0.060936	2.893986	0.0076
BC_DEC	0.283725	0.051542	5.504756	0.0000
BC_FEB	0.176722	0.042989	4.110882	0.0003
BC_JAN	0.310598	0.040007	7.763540	0.0000
BC_MAR	0.247743	0.044977	5.508252	0.0000
BC_MAY	0.298371	0.105891	2.817712	0.0091
BC_NOV	0.449209	0.085953	5.226246	0.0000
BC_OCT	0.849562	0.209156	4.061852	0.0004
C	1800.590	19.93386	90.32819	0.0000
AR(10)	-0.435931	0.179620	-2.426971	0.0225
AR(12)	-0.253422	0.185449	-1.366535	0.1835

R-squared	0.753348	Mean dependent var	1970.355
Adjusted R-squared	0.658481	S.D. dependent var	174.0262
S.E. of regression	101.7002	Akaike info criterion	12.32371
Sum squared resid	268916.4	Schwarz criterion	12.80263
Log likelihood	-216.9886	Hannan-Quinn criter.	12.49255
F-statistic	7.941148	Durbin-Watson stat	1.837746
Prob(F-statistic)	0.000011		

Inverted AR Roots	.92-.28i	.92+.28i	.59+.71i	.59-.71i
	.09+.79i	.09-.79i	-.09-.79i	-.09+.79i
	-.59-.71i	-.59+.71i	-.92-.28i	-.92+.28i

Heteroskedasticity Test: White

F-statistic	0.918920	Prob. F(10,26)	0.5313
Obs*R-squared	9.662063	Prob. Chi-Square(10)	0.4706
Scaled explained SS	4.120563	Prob. Chi-Square(10)	0.9417

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/29/19 Time: 13:38
Sample: 2016M03 2019M03
Included observations: 37
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	14575.75	3502.461	4.161574	0.0003
GRADF_01^2	-0.009271	0.005516	-1.680760	0.1048
GRADF_02^2	-0.002389	0.003794	-0.629793	0.5343
GRADF_03^2	-0.003876	0.002693	-1.439640	0.1619
GRADF_04^2	0.000860	0.002223	0.386788	0.7021
GRADF_05^2	-0.003307	0.003064	-1.079493	0.2903
GRADF_06^2	-0.026138	0.015768	-1.657651	0.1094
GRADF_07^2	-0.011367	0.009955	-1.141748	0.2640
GRADF_08^2	-0.072250	0.060419	-1.195805	0.2426
GRADF_10^2	-0.055748	0.141264	-0.394639	0.6963
GRADF_11^2	-0.186550	0.135779	-1.373925	0.1812

R-squared	0.261137	Mean dependent var	7268.010
Adjusted R-squared	-0.023041	S.D. dependent var	9683.935
S.E. of regression	9794.865	Akaike info criterion	21.45888
Sum squared resid	2.49E+09	Schwarz criterion	21.93780
Log likelihood	-385.9892	Hannan-Quinn criter.	21.62772
F-statistic	0.918920	Durbin-Watson stat	2.093565
Prob(F-statistic)	0.531324		

```
obs        Actual    Fitted    Residual    Residual Plot
2016M03    2000.27   2068.59   -68.3210    |      . *  |    .     |
2016M04    1978.27   1951.60    26.6646    |      .    |*   .     |
2016M05    1968.02   1997.82   -29.8013    |      .   *|    .     |
2016M06    1963.75   1818.50    145.250    |      .    |    . *   |
2016M07    1766.52   1822.73   -56.2139    |      . *  |    .     |
2016M08    1975.54   1849.52    126.017    |      .    |    .*    |
2016M09    1815.47   1858.11   -42.6355    |      .  * |    .     |
2016M10    2014.56   2115.10   -100.534    |      *    |    .     |
2016M11    2035.29   2108.33   -73.0384    |      .*   |    .     |
2016M12    2044.54   2115.95   -71.4102    |      .*   |    .     |
2017M01    2017.33   2200.74   -183.417    |  *   .    |    .     |
2017M02    1976.68   1996.95   -20.2777    |      .   *|    .     |
2017M03    2057.80   2088.11   -30.3127    |      .  * |    .     |
2017M04    1867.47   1884.20   -16.7335    |      .   *|    .     |
2017M05    2025.59   1964.84    60.7517    |      .    |  * .     |
2017M06    1581.28   1682.98   -101.700    |      *    |    .     |
2017M07    2014.38   1802.74    211.645    |      .    |    .     *
2017M08    1850.91   1767.41    83.4944    |      .    |   *.     |
2017M09    1772.69   1815.72   -43.0326    |      .  * |    .     |
2017M10    1978.05   1962.63    15.4183    |      .    |*   .     |
2017M11    2222.13   2120.53    101.594    |      .    |    *     |
2017M12    2244.63   2120.19    124.441    |      .    |    .*    |
2018M01    2351.67   2327.74    23.9282    |      .    |*   .     |
2018M02    2001.16   2063.41   -62.2469    |      . *  |    .     |
2018M03    2150.16   2013.42    136.742    |      .    |    . *   |
2018M04    2081.49   2087.06   -5.57228    |      .    *    .     |
2018M05    1792.50   1835.43   -42.9276    |      .  * |    .     |
2018M06    1740.30   1834.23   -93.9342    |      *    |    .     |
2018M07    1660.94   1758.57   -97.6354    |      *    |    .     |
2018M08    1728.51   1771.21   -42.7058    |      .  * |    .     |
2018M09    1668.22   1728.47   -60.2537    |      . *  |    .     |
2018M10    2011.48   1987.05    24.4342    |      .    |*   .     |
2018M11    2090.98   2066.12    24.8566    |      .    |*   .     |
2018M12    2038.84   2080.53   -41.6862    |      .  * |    .     |
2019M01    2237.01   2118.54    118.465    |      .    |    .*    |
2019M02    2060.33   1987.87    72.4634    |      .    |   *.     |
2019M03    2118.39   2130.17   -11.7743    |      .   *|    .     |
```

DG 19-126
Hearing Exhibit 2

Date: 06/29/19 Time: 13:38
Sample: 2014M11 2042M10
Included observations: 37
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	0.072	0.072	0.2089	
. |*. |	. |*. |	2	0.158	0.154	1.2444	
. |*. |	. |*. |	3	0.113	0.095	1.7892	0.181
. | . |	. | . |	4	0.037	0.001	1.8492	0.397
. | . |	.*| . |	5	-0.059	-0.097	2.0087	0.571
**| . |	**| . |	6	-0.304	-0.328	6.3018	0.178
**| . |	**| . |	7	-0.300	-0.307	10.632	0.059
. | . |	. |*. |	8	0.019	0.152	10.650	0.100
**| . |	.*| . |	9	-0.243	-0.072	13.691	0.057
.*| . |	. | . |	10	-0.112	-0.042	14.360	0.073
. | . |	. | . |	11	-0.018	0.011	14.379	0.109
**| . |	***| . |	12	-0.222	-0.397	17.233	0.069

DG 19-126
Hearing Exhibit 2

Design Day – Total Throughput Model

Dependent Variable: ME
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 06/05/19 Time: 10:27
Sample (adjusted): 4/03/2018 3/31/2019
Included observations: 363 after adjustments
Convergence achieved after 6 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD	675.2696	16.01793	42.15710	0.0000
EDD_50	172.1949	63.44387	2.714131	0.0070
EDD(-1)	132.7049	14.84189	8.941241	0.0000
NOV	3913.797	837.1221	4.675300	0.0000
DEC	5842.488	909.6715	6.422635	0.0000
JAN	8274.873	971.1026	8.521111	0.0000
FEB	7665.239	984.5802	7.785286	0.0000
MAR	4633.282	897.3904	5.163062	0.0000
WEEKDAY=1	10838.38	393.8295	27.52049	0.0000
WEEKDAY=2	12208.06	398.5798	30.62889	0.0000
WEEKDAY=3	12949.54	397.1436	32.60668	0.0000
WEEKDAY=4	13097.83	391.6518	33.44254	0.0000
WEEKDAY=5	12684.86	389.4135	32.57426	0.0000
WEEKDAY=6	10857.94	385.7673	28.14635	0.0000
WEEKDAY=7	9643.324	387.5698	24.88151	0.0000
AR(1)	0.597373	0.043402	13.76365	0.0000

R-squared	0.990831	Mean dependent var	31082.74
Adjusted R-squared	0.990435	S.D. dependent var	17535.48
S.E. of regression	1715.005	Akaike info criterion	17.77530
Sum squared resid	1.02E+09	Schwarz criterion	17.94695
Log likelihood	-3210.216	Hannan-Quinn criter.	17.84353
Durbin-Watson stat	1.929847		

Inverted AR Roots	.60

Design Day – Planning Load Model

Dependent Variable: ME_PL
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 06/05/19 Time: 10:27
Sample (adjusted): 4/03/2018 3/31/2019
Included observations: 363 after adjustments
Convergence achieved after 5 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD	595.6509	14.03948	42.42685	0.0000
EDD_50	176.8308	55.37940	3.193078	0.0015
EDD(-1)	123.6819	13.00973	9.506874	0.0000
NOV	3629.341	752.1686	4.825170	0.0000
DEC	5809.254	818.5219	7.097250	0.0000
JAN	8060.096	871.4055	9.249535	0.0000
FEB	7546.078	885.4522	8.522288	0.0000
MAR	4430.356	810.2649	5.467788	0.0000
WEEKDAY=1	6197.570	353.7244	17.52090	0.0000
WEEKDAY=2	6871.647	357.8890	19.20050	0.0000
WEEKDAY=3	7273.471	356.6348	20.39473	0.0000
WEEKDAY=4	7394.793	351.7371	21.02363	0.0000
WEEKDAY=5	7185.316	349.8840	20.53628	0.0000
WEEKDAY=6	6465.036	346.6042	18.65250	0.0000
WEEKDAY=7	5797.165	348.1580	16.65096	0.0000
AR(1)	0.613624	0.042572	14.41362	0.0000

R-squared	0.991349	Mean dependent var	24166.58
Adjusted R-squared	0.990975	S.D. dependent var	15816.82
S.E. of regression	1502.581	Akaike info criterion	17.51083
Sum squared resid	7.83E+08	Schwarz criterion	17.68249
Log likelihood	-3162.216	Hannan-Quinn criter.	17.57906
Durbin-Watson stat	1.988000		

Inverted AR Roots	.61

NH Division Statistical Model Results

Variable Nomenclature

Variable	Description
POPULATION	Total Population
C	Constant
TREND	Linear Trend
WINTER_MONTHS	November - March
JAN	January
FEB	February
MAR	March
APR	April
MAY	May
JUN	June
JUL	July
AUG	August
SEP	September
OCT	October
NOV	November
DEC	December
BC_JAN	January Bill Cycle EDD
BC_FEB	February Bill Cycle EDD
BC_MAR	March Bill Cycle EDD
BC_APR	April Bill Cycle EDD
BC_MAY	May Bill Cycle EDD
BC_JUN	June Bill Cycle EDD
BC_JUL	July Bill Cycle EDD
BC_AUG	August Bill Cycle EDD
BC_SEP	September Bill Cycle EDD
BC_OCT	October Bill Cycle EDD
BC_NOV	November Bill Cycle EDD
BC_DEC	December Bill Cycle EDD
AR(1)	Autoregressive Term, Lag 1
AR(3)	Autoregressive Term, Lag 3
AR(2)	Autoregressive Term, Lag 2
AR(10)	Autoregressive Term, Lag 10
D_2018M5_F	Dummy Variable - May 2018 and Forward
D_2018M10_F	Dummy Variable - October 2018 and Forward
D_2017M11_F	Dummy Variable - November 2017 and Forward
D_2017M4_F	Dummy Variable - April 2017 and Forward
D_2015M11_F	Dummy Variable - November 2015 and Forward

DG 19-126
Hearing Exhibit 2

Residential Customer Segment – Customer Model

Dependent Variable: RES_CUST
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 06/29/19 Time: 13:20
Sample (adjusted): 2014M12 2019M03
Included observations: 52 after adjustments
Convergence achieved after 4 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
POPULATION*TREND	0.125777	0.007465	16.84955	0.0000
NOV	259.9736	32.20056	8.073574	0.0000
OCT	133.0789	24.29952	5.476605	0.0000
DEC	319.4248	35.72992	8.939981	0.0000
JAN	337.3675	37.90231	8.900974	0.0000
FEB	331.3572	38.80903	8.538146	0.0000
MAR	309.0528	38.50762	8.025756	0.0000
APR	317.5836	36.21133	8.770282	0.0000
MAY	216.1594	31.85455	6.785826	0.0000
JUN	118.8036	24.14976	4.919454	0.0000
C	23133.21	144.5323	160.0556	0.0000
AR(1)	0.834131	0.092122	9.054645	0.0000

R-squared	0.997078	Mean dependent var	25400.60
Adjusted R-squared	0.996275	S.D. dependent var	774.8327
S.E. of regression	47.29017	Akaike info criterion	10.74966
Sum squared resid	89454.40	Schwarz criterion	11.19994
Log likelihood	-267.4911	Hannan-Quinn criter.	10.92229
F-statistic	1241.026	Durbin-Watson stat	1.784067
Prob(F-statistic)	0.000000		

Inverted AR Roots	.83

Heteroskedasticity Test: White

F-statistic	3.070406	Prob. F(11,40)	0.0045
Obs*R-squared	23.80596	Prob. Chi-Square(11)	0.0136
Scaled explained SS	19.73275	Prob. Chi-Square(11)	0.0491

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/29/19 Time: 14:10
Sample: 2014M12 2019M03
Included observations: 52
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	5822.014	1091.498	5.333968	0.0000
GRADF_01^2	1.63E-05	5.64E-05	0.289556	0.7737
GRADF_02^2	-1984.771	1492.849	-1.329519	0.1912
GRADF_03^2	-4528.007	1466.379	-3.087884	0.0037
GRADF_04^2	-4256.143	1657.970	-2.567080	0.0141
GRADF_05^2	-1701.398	1526.181	-1.114808	0.2716
GRADF_06^2	-4480.836	1617.037	-2.771016	0.0084
GRADF_07^2	-1917.208	1509.007	-1.270510	0.2112
GRADF_08^2	-4474.861	1662.999	-2.690838	0.0104
GRADF_09^2	-1594.977	1464.755	-1.088904	0.2827
GRADF_10^2	-4028.267	1471.424	-2.737666	0.0092
GRADF_12^2	-0.011411	0.042170	-0.270607	0.7881

R-squared	0.457807	Mean dependent var	1720.277
Adjusted R-squared	0.308704	S.D. dependent var	2907.530
S.E. of regression	2417.443	Akaike info criterion	18.61798
Sum squared resid	2.34E+08	Schwarz criterion	19.06827
Log likelihood	-472.0675	Hannan-Quinn criter.	18.79061
F-statistic	3.070406	Durbin-Watson stat	1.089451
Prob(F-statistic)	0.004543		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2014M12</td><td>24361.0</td><td>24330.9</td><td>30.1446</td><td>| . | *. |</td></tr>
<tr><td>2015M01</td><td>24399.0</td><td>24398.7</td><td>0.30198</td><td>| . * . |</td></tr>
<tr><td>2015M02</td><td>24425.0</td><td>24418.0</td><td>7.04366</td><td>| . |* . |</td></tr>
<tr><td>2015M03</td><td>24439.0</td><td>24430.9</td><td>8.07192</td><td>| . |* . |</td></tr>
<tr><td>2015M04</td><td>24505.0</td><td>24478.2</td><td>26.7656</td><td>| . | * . |</td></tr>
<tr><td>2015M05</td><td>24439.0</td><td>24433.5</td><td>5.50951</td><td>| . * . |</td></tr>
<tr><td>2015M06</td><td>24343.0</td><td>24374.3</td><td>-31.3367</td><td>| .* | . |</td></tr>
<tr><td>2015M07</td><td>24256.0</td><td>24265.3</td><td>-9.27936</td><td>| . *| . |</td></tr>
<tr><td>2015M08</td><td>24325.0</td><td>24300.5</td><td>24.5482</td><td>| . | * . |</td></tr>
<tr><td>2015M09</td><td>24377.0</td><td>24366.6</td><td>10.3646</td><td>| . |* . |</td></tr>
<tr><td>2015M10</td><td>24579.0</td><td>24551.7</td><td>27.2596</td><td>| . | * . |</td></tr>
<tr><td>2015M11</td><td>24731.0</td><td>24744.8</td><td>-13.7715</td><td>| . *| . |</td></tr>
<tr><td>2015M12</td><td>24829.0</td><td>24833.8</td><td>-4.82930</td><td>| . * . |</td></tr>
<tr><td>2016M01</td><td>24888.0</td><td>24892.6</td><td>-4.58870</td><td>| . * . |</td></tr>
<tr><td>2016M02</td><td>24935.0</td><td>24929.5</td><td>5.48139</td><td>| . * . |</td></tr>
<tr><td>2016M03</td><td>25000.0</td><td>24960.1</td><td>39.8896</td><td>| . | *. |</td></tr>
<tr><td>2016M04</td><td>25039.0</td><td>25050.2</td><td>-11.2017</td><td>| . *| . |</td></tr>
<tr><td>2016M05</td><td>25005.0</td><td>24982.8</td><td>22.2029</td><td>| . | * . |</td></tr>
<tr><td>2016M06</td><td>25005.0</td><td>24950.4</td><td>54.6493</td><td>| . | .* |</td></tr>
<tr><td>2016M07</td><td>24846.0</td><td>24921.5</td><td>-75.4562</td><td>| * . | . |</td></tr>
<tr><td>2016M08</td><td>24774.0</td><td>24896.6</td><td>-122.620</td><td>|* . | . |</td></tr>
<tr><td>2016M09</td><td>24928.0</td><td>24845.3</td><td>82.7223</td><td>| . | . * |</td></tr>
<tr><td>2016M10</td><td>25086.0</td><td>25115.5</td><td>-29.5217</td><td>| .* | . |</td></tr>
<tr><td>2016M11</td><td>25233.0</td><td>25271.9</td><td>-38.9386</td><td>| .* | . |</td></tr>
<tr><td>2016M12</td><td>25342.0</td><td>25356.9</td><td>-14.8836</td><td>| . *| . |</td></tr>
<tr><td>2017M01</td><td>25395.0</td><td>25424.9</td><td>-29.9080</td><td>| .* | . |</td></tr>
<tr><td>2017M02</td><td>25432.0</td><td>25456.8</td><td>-24.8325</td><td>| . * | . |</td></tr>
<tr><td>2017M03</td><td>25440.0</td><td>25479.2</td><td>-39.1621</td><td>| .* | . |</td></tr>
<tr><td>2017M04</td><td>25500.0</td><td>25521.6</td><td>-21.5917</td><td>| . * | . |</td></tr>
<tr><td>2017M05</td><td>25425.0</td><td>25472.1</td><td>-47.1256</td><td>| * | . |</td></tr>
<tr><td>2017M06</td><td>25390.0</td><td>25405.7</td><td>-15.6752</td><td>| . *| . |</td></tr>
<tr><td>2017M07</td><td>25399.0</td><td>25347.7</td><td>51.3117</td><td>| . | * |</td></tr>
<tr><td>2017M08</td><td>25559.0</td><td>25463.1</td><td>95.8733</td><td>| . | . * |</td></tr>
<tr><td>2017M09</td><td>25706.0</td><td>25605.4</td><td>100.600</td><td>| . | . *|</td></tr>
<tr><td>2017M10</td><td>25822.0</td><td>25869.9</td><td>-47.9436</td><td>| * | . |</td></tr>
<tr><td>2017M11</td><td>26029.0</td><td>25991.4</td><td>37.5749</td><td>| . | *. |</td></tr>
<tr><td>2017M12</td><td>26110.0</td><td>26126.6</td><td>-16.5512</td><td>| . *| . |</td></tr>
<tr><td>2018M01</td><td>26135.0</td><td>26171.3</td><td>-36.3297</td><td>| .* | . |</td></tr>
<tr><td>2018M02</td><td>26155.0</td><td>26180.1</td><td>-25.0763</td><td>| . * | . |</td></tr>
<tr><td>2018M03</td><td>26173.0</td><td>26188.3</td><td>-15.3388</td><td>| . *| . |</td></tr>
<tr><td>2018M04</td><td>26225.0</td><td>26239.4</td><td>-14.3997</td><td>| . *| . |</td></tr>
<tr><td>2018M05</td><td>26178.0</td><td>26183.1</td><td>-5.07412</td><td>| . * . |</td></tr>
<tr><td>2018M06</td><td>26103.0</td><td>26140.0</td><td>-36.9915</td><td>| .* | . |</td></tr>
<tr><td>2018M07</td><td>26047.0</td><td>26048.8</td><td>-1.76429</td><td>| . * . |</td></tr>
<tr><td>2018M08</td><td>26041.0</td><td>26110.0</td><td>-69.0003</td><td>| * . | . |</td></tr>
<tr><td>2018M09</td><td>26169.0</td><td>26113.9</td><td>55.1125</td><td>| . | .* |</td></tr>
<tr><td>2018M10</td><td>26406.0</td><td>26362.7</td><td>43.3216</td><td>| . | * |</td></tr>
<tr><td>2018M11</td><td>26592.0</td><td>26585.1</td><td>6.88298</td><td>| . |* . |</td></tr>
<tr><td>2018M12</td><td>26699.0</td><td>26702.8</td><td>-3.77295</td><td>| . * . |</td></tr>
<tr><td>2019M01</td><td>26828.0</td><td>26769.3</td><td>58.6659</td><td>| . | .* |</td></tr>
<tr><td>2019M02</td><td>26888.0</td><td>26864.8</td><td>23.1684</td><td>| . | * . |</td></tr>
<tr><td>2019M03</td><td>26896.0</td><td>26906.5</td><td>-10.5012</td><td>| . *| . |</td></tr>
</table>

Date: 06/29/19 Time: 14:11
Sample: 2014M11 2042M10
Included observations: 52
Q-statistic probabilities adjusted for 1 ARMA term

<table>
<tr><th>Autocorrelation</th><th>Partial Correlation</th><th></th><th>AC</th><th>PAC</th><th>Q-Stat</th><th>Prob*</th></tr>
<tr><td>. |*. |</td><td>. |*. |</td><td>1</td><td>0.102</td><td>0.102</td><td>0.5759</td><td></td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>2</td><td>-0.090</td><td>-0.101</td><td>1.0266</td><td>0.311</td></tr>
<tr><td>. |*. |</td><td>. |*. |</td><td>3</td><td>0.101</td><td>0.124</td><td>1.6143</td><td>0.446</td></tr>
<tr><td>. | . |</td><td>. | . |</td><td>4</td><td>-0.005</td><td>-0.042</td><td>1.6155</td><td>0.656</td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>5</td><td>-0.170</td><td>-0.147</td><td>3.3493</td><td>0.501</td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>6</td><td>-0.097</td><td>-0.079</td><td>3.9210</td><td>0.561</td></tr>
<tr><td>. | . |</td><td>. | . |</td><td>7</td><td>-0.046</td><td>-0.057</td><td>4.0549</td><td>0.669</td></tr>
<tr><td>.*| . |</td><td>. | . |</td><td>8</td><td>-0.078</td><td>-0.053</td><td>4.4385</td><td>0.728</td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>9</td><td>-0.130</td><td>-0.121</td><td>5.5454</td><td>0.698</td></tr>
<tr><td>. | . |</td><td>. | . |</td><td>10</td><td>-0.002</td><td>-0.007</td><td>5.5456</td><td>0.784</td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>11</td><td>-0.130</td><td>-0.186</td><td>6.7022</td><td>0.753</td></tr>
<tr><td>.*| . |</td><td>.*| . |</td><td>12</td><td>-0.175</td><td>-0.168</td><td>8.8601</td><td>0.635</td></tr>
</table>

DG 19-126
Hearing Exhibit 2

Residential Customer Segment - Use Per Customer Model

Dependent Variable: RES_UPC
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 05/22/19 Time: 08:43
Sample (adjusted): 2014M12 2019M03
Included observations: 52 after adjustments
Convergence achieved after 5 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BC_DEC	0.087603	0.001723	50.85294	0.0000
BC_FEB	0.093133	0.001310	71.06794	0.0000
BC_JAN	0.094147	0.001335	70.50728	0.0000
BC_JUN	0.048568	0.008386	5.791814	0.0000
BC_MAR	0.089973	0.001506	59.75359	0.0000
BC_MAY	0.060923	0.003786	16.09260	0.0000
BC_NOV	0.061226	0.002886	21.21250	0.0000
BC_OCT	0.035144	0.006293	5.584936	0.0000
BC_APR	0.079738	0.002003	39.80744	0.0000
C	13.12900	0.993554	13.21418	0.0000
AR(1)	0.300351	0.150491	1.995811	0.0526

R-squared	0.997067	Mean dependent var	64.08161
Adjusted R-squared	0.996352	S.D. dependent var	46.48163
S.E. of regression	2.807493	Akaike info criterion	5.087866
Sum squared resid	323.1628	Schwarz criterion	5.500629
Log likelihood	-121.2845	Hannan-Quinn criter.	5.246110
F-statistic	1393.862	Durbin-Watson stat	1.889680
Prob(F-statistic)	0.000000		

Inverted AR Roots	.30

Heteroskedasticity Test: White

F-statistic	1.681394	Prob. F(10,41)	0.1183
Obs*R-squared	15.12308	Prob. Chi-Square(10)	0.1276
Scaled explained SS	8.960858	Prob. Chi-Square(10)	0.5358

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/30/19   Time: 11:24
Sample: 2014M12 2019M03
Included observations: 52
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3.629156	2.200900	1.648942	0.1068
GRADF_01^2	9.25E-06	4.70E-06	1.968396	0.0558
GRADF_02^2	2.24E-06	2.74E-06	0.817893	0.4181
GRADF_03^2	7.04E-06	2.76E-06	2.551831	0.0145
GRADF_04^2	-5.08E-05	0.000125	-0.405833	0.6870
GRADF_05^2	-1.72E-06	3.40E-06	-0.504784	0.6164
GRADF_06^2	1.44E-05	2.29E-05	0.629381	0.5326
GRADF_07^2	2.06E-05	1.23E-05	1.674740	0.1016
GRADF_08^2	-4.86E-05	6.94E-05	-0.700728	0.4874
GRADF_09^2	7.14E-06	5.94E-06	1.200970	0.2367
GRADF_11^2	-0.070255	0.137631	-0.510460	0.6125

R-squared	0.290828	Mean dependent var	6.214668
Adjusted R-squared	0.117860	S.D. dependent var	8.664105
S.E. of regression	8.137529	Akaike info criterion	7.216255
Sum squared resid	2714.994	Schwarz criterion	7.629018
Log likelihood	-176.6226	Hannan-Quinn criter.	7.374499
F-statistic	1.681394	Durbin-Watson stat	2.286546
Prob(F-statistic)	0.118321		

obs	Actual	Fitted	Residual
2014M12	97.5204	97.6394	-0.11904
2015M01	132.509	128.897	3.61187
2015M02	158.418	156.540	1.87811
2015M03	134.511	134.588	-0.07640
2015M04	87.3595	86.3357	1.02380
2015M05	34.5215	38.7936	-4.27205
2015M06	21.6948	20.4598	1.23500
2015M07	15.4790	13.1490	2.33006
2015M08	13.7488	13.8348	-0.08601
2015M09	14.1711	13.3152	0.85590
2015M10	24.3195	23.4229	0.89652
2015M11	45.7375	46.3705	-0.63306
2015M12	75.1019	79.7137	-4.61177
2016M01	105.302	109.161	-3.85904
2016M02	121.043	118.091	2.95172
2016M03	98.7262	100.814	-2.08757
2016M04	68.0754	73.3065	-5.23111
2016M05	42.0158	42.1120	-0.09620
2016M06	19.4479	20.0137	-0.56580
2016M07	13.3802	12.7950	0.58522
2016M08	14.0821	13.2045	0.87768
2016M09	13.5075	13.4153	0.09226
2016M10	22.6517	22.3450	0.30663
2016M11	48.8547	48.7050	0.14971
2016M12	91.4048	95.6461	-4.24132
2017M01	118.447	119.396	-0.94879
2017M02	111.588	116.685	-5.09749
2017M03	103.885	104.072	-0.18629
2017M04	85.4858	81.9261	3.55967
2017M05	43.6232	40.9535	2.66968
2017M06	27.1279	25.8078	1.32014
2017M07	15.8355	13.8472	1.98830
2017M08	13.7500	13.9419	-0.19195
2017M09	14.8004	13.3155	1.48489
2017M10	17.2935	18.5512	-1.25769
2017M11	37.3554	42.9639	-5.60854
2017M12	101.094	98.2783	2.81569
2018M01	157.790	153.633	4.15688
2018M02	119.740	121.297	-1.55745
2018M03	97.8126	96.5596	1.25298
2018M04	87.1027	87.1645	-0.06175
2018M05	42.1703	40.3895	1.78071
2018M06	20.9309	21.6071	-0.67612
2018M07	13.9753	13.0946	0.88074
2018M08	12.1281	13.3832	-1.25509
2018M09	12.4705	12.8284	-0.35786
2018M10	22.2055	22.6310	-0.42554
2018M11	61.5428	57.6979	3.84496
2018M12	111.671	107.612	4.05844
2019M01	121.443	126.524	-5.08146
2019M02	132.067	131.092	0.97472
2019M03	115.325	114.322	1.00311

Date: 06/30/19 Time: 11:25
Sample: 2014M11 2042M10
Included observations: 52
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	0.054	0.054	0.1581	
.*| . |	.*| . |	2	-0.198	-0.201	2.3534	0.125
. | . |	. |*. |	3	0.055	0.083	2.5297	0.282
.*| . |	.*| . |	4	-0.080	-0.137	2.9077	0.406
.*| . |	. | . |	5	-0.074	-0.030	3.2374	0.519
.*| . |	.*| . |	6	-0.094	-0.146	3.7770	0.582
. | . |	. | . |	7	-0.022	-0.012	3.8073	0.703
. |*. |	. |*. |	8	0.181	0.139	5.9023	0.551
. |*. |	. | . |	9	0.081	0.057	6.3331	0.610
. | . |	. |*. |	10	0.051	0.100	6.5098	0.688
. |*. |	. |*. |	11	0.197	0.199	9.1798	0.515
.*| . |	.*| . |	12	-0.176	-0.181	11.364	0.413

DG 19-126
Hearing Exhibit 2

LLF Customer Segment – Customer Model

Dependent Variable: LLF_CUST
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 05/13/19 Time: 08:03
Sample (adjusted): 2015M01 2019M03
Included observations: 51 after adjustments
Convergence achieved after 18 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
POPULATION	27.65704	2.366865	11.68510	0.0000
C	-5840.207	973.3161	-6.000319	0.0000
OCT	101.1450	18.56433	5.448353	0.0000
NOV	176.4796	26.83430	6.576642	0.0000
DEC	254.7828	27.21731	9.361057	0.0000
JAN	312.2385	25.98463	12.01627	0.0000
FEB	320.9656	25.81952	12.43112	0.0000
MAR	262.4986	24.48209	10.72207	0.0000
APR	128.7309	17.42639	7.387127	0.0000
AR(1)	0.928515	0.112929	8.222109	0.0000
AR(2)	-0.731855	0.120010	-6.098285	0.0000

R-squared	0.961998	Mean dependent var	5678.275
Adjusted R-squared	0.952497	S.D. dependent var	154.4378
S.E. of regression	33.65989	Akaike info criterion	10.05892
Sum squared resid	45319.54	Schwarz criterion	10.47559
Log likelihood	-245.5024	Hannan-Quinn criter.	10.21814
F-statistic	101.2572	Durbin-Watson stat	1.990748
Prob(F-statistic)	0.000000		

Inverted AR Roots	.46+.72i	.46-.72i

Heteroskedasticity Test: White

F-statistic	0.836164	Prob. F(10,40)	0.5973
Obs*R-squared	8.817810	Prob. Chi-Square(10)	0.5495
Scaled explained SS	4.553846	Prob. Chi-Square(10)	0.9189

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/30/19 Time: 11:27
Sample: 2015M01 2019M03
Included observations: 51
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	8700.921	13696.49	0.635267	0.5289
GRADF_01^2	-0.065688	0.125500	-0.523410	0.6036
GRADF_03^2	-27.68174	707.2192	-0.039142	0.9690
GRADF_04^2	-831.5566	822.5996	-1.010889	0.3181
GRADF_05^2	902.4204	801.0773	1.126509	0.2667
GRADF_06^2	-1345.357	791.2518	-1.700289	0.0968
GRADF_07^2	-79.42078	741.6075	-0.107093	0.9153
GRADF_08^2	-141.1897	724.2851	-0.194937	0.8464
GRADF_09^2	-242.1099	657.8585	-0.368027	0.7148
GRADF_10^2	0.028731	0.068973	0.416555	0.6792
GRADF_11^2	-0.128064	0.070848	-1.807575	0.0782

R-squared	0.172898	Mean dependent var	888.6184
Adjusted R-squared	-0.033877	S.D. dependent var	1162.919
S.E. of regression	1182.453	Akaike info criterion	17.17700
Sum squared resid	55927803	Schwarz criterion	17.59366
Log likelihood	-427.0134	Hannan-Quinn criter.	17.33622
F-statistic	0.836164	Durbin-Watson stat	2.550303
Prob(F-statistic)	0.597308		

obs	Actual	Fitted	Residual	Residual Plot
2015M01	5669.00	5699.16	-30.1636	| .* | . |
2015M02	5674.00	5707.82	-33.8248	| * | . |
2015M03	5662.00	5676.22	-14.2193	| . * | . |
2015M04	5576.00	5589.83	-13.8327	| . * | . |
2015M05	5472.00	5476.14	-4.13529	| . *| . |
2015M06	5421.00	5466.58	-45.5786	| *. | . |
2015M07	5406.00	5404.57	1.42507	| . * . |
2015M08	5383.00	5432.02	-49.0195	| * . | . |
2015M09	5434.00	5425.35	8.65198	| . |* . |
2015M10	5647.00	5594.64	52.3562	| . | . * |
2015M11	5717.00	5740.27	-23.2701	| . * | . |
2015M12	5741.00	5735.66	5.34208	| . |* . |
2016M01	5764.00	5750.35	13.6497	| . | * . |
2016M02	5779.00	5770.81	8.18754	| . |* . |
2016M03	5756.00	5747.14	8.85785	| . |* . |
2016M04	5681.00	5645.96	35.0370	| . | * |
2016M05	5574.00	5549.00	25.0048	| . | * . |
2016M06	5574.00	5530.09	43.9131	| . | .* |
2016M07	5477.00	5517.77	-40.7659	| *. | . |
2016M08	5430.00	5431.06	-1.05682	| . * . |
2016M09	5540.00	5461.90	78.0956	| . | . *
2016M10	5695.00	5702.96	-7.95591	| . *| . |
2016M11	5766.00	5751.32	14.6782	| . | * . |
2016M12	5831.00	5789.57	41.4269	| . | .* |
2017M01	5820.00	5841.43	-21.4266	| . * | . |
2017M02	5824.00	5799.50	24.4969	| . | * . |
2017M03	5815.00	5790.35	24.6472	| . | * . |
2017M04	5722.00	5708.61	13.3935	| . | * . |
2017M05	5613.00	5586.37	26.6267	| . | *. |
2017M06	5526.00	5578.13	-52.1337	| * . | . |
2017M07	5513.00	5486.91	26.0855	| . | *. |
2017M08	5496.00	5542.88	-46.8766	| *. | . |
2017M09	5523.00	5540.77	-17.7690	| . * | . |
2017M10	5657.00	5683.76	-26.7613	| .* | . |
2017M11	5805.00	5774.00	31.0045	| . | *. |
2017M12	5851.00	5899.99	-48.9909	| * . | . |
2018M01	5876.00	5878.47	-2.47314	| . * . |
2018M02	5883.00	5884.92	-1.92483	| . * . |
2018M03	5891.00	5852.80	38.2041	| . | * |
2018M04	5847.00	5786.33	60.6658	| . | . * |
2018M05	5703.00	5696.28	6.71585	| . |* . |
2018M06	5613.00	5620.61	-7.61078	| . *| . |
2018M07	5567.00	5552.43	14.5662	| . | * . |
2018M08	5561.00	5579.41	-18.4080	| . * | . |
2018M09	5595.00	5611.57	-16.5709	| . * | . |
2018M10	5770.00	5752.74	17.2584	| . | * . |
2018M11	5862.00	5875.45	-13.4495	| . * | . |
2018M12	5885.00	5919.10	-34.1019	| * | . |
2019M01	5899.00	5916.93	-17.9344	| . * | . |
2019M02	5908.00	5929.33	-21.3341	| . * | . |
2019M03	5898.00	5906.70	-8.70259	| . *| . |

DG 19-126
Hearing Exhibit 2

Date: 06/30/19 Time: 11:28
Sample: 2014M11 2042M10
Included observations: 51
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	-0.006	-0.006	0.0021	
. |*. |	. |*. |	2	0.110	0.110	0.6723	
. |*. |	. |*. |	3	0.192	0.196	2.7481	0.097
. | . |	. | . |	4	0.014	0.008	2.7590	0.252
. | . |	. | . |	5	0.060	0.018	2.9677	0.397
. |*. |	. | . |	6	0.105	0.071	3.6337	0.458
.*| . |	.*| . |	7	-0.085	-0.098	4.0802	0.538
. | . |	. | . |	8	-0.014	-0.055	4.0917	0.664
**| . |	**| . |	9	-0.267	-0.303	8.6936	0.275
**| . |	**| . |	10	-0.221	-0.242	11.910	0.155
. |*. |	. |** |	11	0.205	0.291	14.744	0.098
.*| . |	. |*. |	12	-0.080	0.137	15.192	0.125

DG 19-126
Hearing Exhibit 2

LLF Customer Segment - Use Per Customer Model

Dependent Variable: LLF_UPC
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 06/30/19 Time: 11:34
Sample (adjusted): 2014M12 2019M03
Included observations: 52 after adjustments
Convergence achieved after 10 iterations
White heteroskedasticity-consistent standard errors & covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BC_APR	0.514568	0.017036	30.20440	0.0000
BC_DEC	0.602229	0.012603	47.78330	0.0000
BC_FEB	0.636297	0.013292	47.87077	0.0000
BC_JAN	0.660268	0.011827	55.82661	0.0000
BC_MAR	0.618766	0.015646	39.54787	0.0000
BC_MAY	0.344482	0.049176	7.005043	0.0000
BC_NOV	0.457267	0.020557	22.24407	0.0000
BC_OCT	0.315364	0.023964	13.15991	0.0000
C	114.6390	10.11969	11.32831	0.0000
TREND*D_2017M11_F	0.291468	0.168814	1.726565	0.0918
AR(1)	0.295760	0.268010	1.103542	0.2762

R-squared	0.996081	Mean dependent var	464.9250
Adjusted R-squared	0.995125	S.D. dependent var	327.3281
S.E. of regression	22.85511	Akaike info criterion	9.281632
Sum squared resid	21416.60	Schwarz criterion	9.694395
Log likelihood	-230.3224	Hannan-Quinn criter.	9.439875
F-statistic	1041.993	Durbin-Watson stat	1.930827
Prob(F-statistic)	0.000000		

Inverted AR Roots	.30

DG 19-126
Hearing Exhibit 2

Heteroskedasticity Test: White

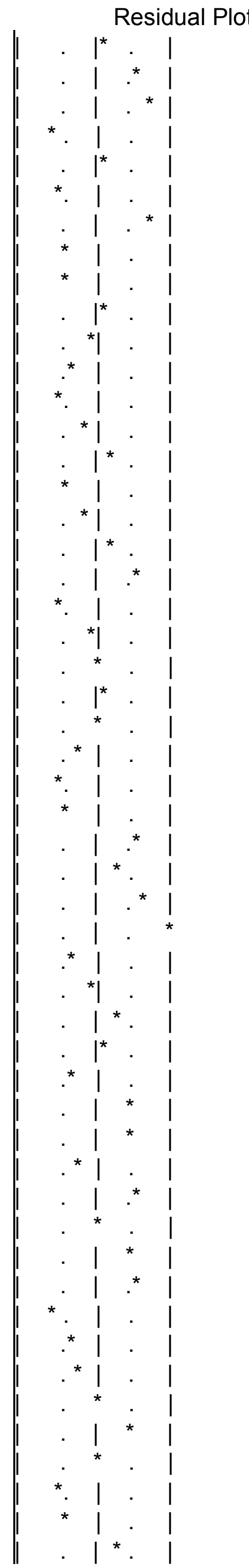
F-statistic	1.277276	Prob. F(10,41)	0.2748
Obs*R-squared	12.35167	Prob. Chi-Square(10)	0.2622
Scaled explained SS	3.955905	Prob. Chi-Square(10)	0.9493

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/30/19 Time: 11:35
Sample: 2014M12 2019M03
Included observations: 52
White heteroskedasticity-consistent standard errors & covariance
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	383.2761	112.1952	3.416154	0.0014
GRADF_01^2	-0.000496	0.000147	-3.368454	0.0017
GRADF_02^2	-0.000136	0.000166	-0.819012	0.4175
GRADF_03^2	0.000102	0.000173	0.587707	0.5600
GRADF_04^2	6.44E-05	8.69E-05	0.740983	0.4629
GRADF_05^2	0.000100	0.000159	0.631305	0.5313
GRADF_06^2	0.000993	0.001114	0.892124	0.3775
GRADF_07^2	-0.000122	0.000427	-0.286121	0.7762
GRADF_08^2	-0.005353	0.001525	-3.510759	0.0011
GRADF_10^2	-0.028612	0.055354	-0.516883	0.6080
GRADF_11^2	0.140951	0.171197	0.823326	0.4151

R-squared	0.237532	Mean dependent var	411.8576
Adjusted R-squared	0.051564	S.D. dependent var	422.1417
S.E. of regression	411.1139	Akaike info criterion	15.06102
Sum squared resid	6929601.	Schwarz criterion	15.47379
Log likelihood	-380.5866	Hannan-Quinn criter.	15.21927
F-statistic	1.277276	Durbin-Watson stat	1.927989
Prob(F-statistic)	0.274809		

obs	Actual	Fitted	Residual
2014M12	699.764	694.945	4.81872
2015M01	953.147	927.996	25.1510
2015M02	1131.97	1094.90	37.0688
2015M03	925.676	957.114	-31.4375
2015M04	583.653	580.113	3.53989
2015M05	230.128	257.062	-26.9342
2015M06	141.189	106.514	34.6754
2015M07	99.8553	122.492	-22.6362
2015M08	87.6662	110.267	-22.6004
2015M09	111.515	106.661	4.85341
2015M10	198.664	203.278	-4.61458
2015M11	342.223	358.553	-16.3300
2015M12	541.276	567.621	-26.3457
2016M01	778.871	788.653	-9.78214
2016M02	847.042	836.900	10.1416
2016M03	694.413	716.166	-21.7532
2016M04	491.594	500.183	-8.58981
2016M05	294.679	283.930	10.7486
2016M06	141.494	116.538	24.9556
2016M07	95.1941	122.582	-27.3874
2016M08	102.538	108.888	-6.35003
2016M09	110.730	111.060	-0.33037
2016M10	198.259	195.162	3.09723
2016M11	380.953	379.970	0.98297
2016M12	667.899	681.797	-13.8985
2017M01	839.574	864.691	-25.1173
2017M02	798.147	818.051	-19.9044
2017M03	770.445	743.536	26.9087
2017M04	580.776	567.778	12.9985
2017M05	302.423	272.361	30.0623
2017M06	171.448	125.145	46.3030
2017M07	114.552	131.441	-16.8891
2017M08	109.763	114.613	-4.85064
2017M09	126.317	113.197	13.1207
2017M10	164.469	162.244	2.22524
2017M11	336.783	355.118	-18.3356
2017M12	745.377	721.698	23.6794
2018M01	1140.21	1118.19	22.0223
2018M02	855.113	867.782	-12.6684
2018M03	730.577	702.966	27.6108
2018M04	614.476	613.610	0.86552
2018M05	308.606	286.863	21.7432
2018M06	162.329	138.147	24.1819
2018M07	110.104	140.530	-30.4260
2018M08	106.706	125.289	-18.5833
2018M09	113.068	124.489	-11.4212
2018M10	213.066	213.617	-0.55063
2018M11	485.786	464.876	20.9100
2018M12	781.966	780.337	1.62902
2019M01	895.172	919.553	-24.3809
2019M02	916.152	939.906	-23.7545
2019M03	832.304	820.726	11.5778



DG 19-126
Hearing Exhibit 2

Date: 06/30/19 Time: 11:36
Sample: 2014M11 2042M10
Included observations: 52
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	0.031	0.031	0.0526	
.*| . |	.*| . |	2	-0.108	-0.109	0.7110	0.399
. | . |	. | . |	3	-0.032	-0.026	0.7713	0.680
. | . |	. | . |	4	0.016	0.006	0.7859	0.853
. | . |	. | . |	5	0.037	0.030	0.8674	0.929
. | . |	. | . |	6	-0.011	-0.012	0.8750	0.972
. | . |	. | . |	7	0.022	0.031	0.9059	0.989
. | . |	. | . |	8	-0.036	-0.039	0.9892	0.995
. | . |	. | . |	9	0.064	0.072	1.2578	0.996
. | . |	.*| . |	10	-0.055	-0.069	1.4585	0.997
. | . |	. | . |	11	-0.053	-0.037	1.6540	0.998
. |** |	. |** |	12	0.267	0.267	6.6660	0.825

HLF Customer Segment – Customer Model

Dependent Variable: HLF_CUST
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 05/14/19 Time: 08:43
Sample (adjusted): 2015M01 2019M03
Included observations: 51 after adjustments
Convergence achieved after 7 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
OCT	-20.21069	3.623567	-5.577568	0.0000
NOV	-34.21057	4.953943	-6.905726	0.0000
DEC	-33.55319	5.688300	-5.898633	0.0000
JAN	-32.09789	5.817583	-5.517392	0.0000
FEB	-34.67771	5.498734	-6.306489	0.0000
MAR	-27.84636	4.764682	-5.844327	0.0000
APR	-13.60552	3.167097	-4.295897	0.0001
C	1114.121	11.94224	93.29247	0.0000
D_2018M10_F*TREND	0.878236	0.135474	6.482715	0.0000
AR(1)	1.167604	0.165903	7.037867	0.0000
AR(2)	-0.259119	0.171841	-1.507897	0.1394

R-squared	0.932877	Mean dependent var	1109.902
Adjusted R-squared	0.916096	S.D. dependent var	22.15333
S.E. of regression	6.416964	Akaike info criterion	6.744194
Sum squared resid	1647.097	Schwarz criterion	7.160862
Log likelihood	-160.9769	Hannan-Quinn criter.	6.903415
F-statistic	55.59215	Durbin-Watson stat	1.961515
Prob(F-statistic)	0.000000		

Inverted AR Roots	.87	.30

Heteroskedasticity Test: White

F-statistic	1.281193	Prob. F(10,40)	0.2735
Obs*R-squared	12.37236	Prob. Chi-Square(10)	0.2609
Scaled explained SS	11.57224	Prob. Chi-Square(10)	0.3147

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/30/19 Time: 11:40
Sample: 2015M01 2019M03
Included observations: 51
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	37.72663	15.81603	2.385341	0.0219
GRADF_01^2	43.62225	24.99188	1.745457	0.0886
GRADF_02^2	-7.275917	26.78016	-0.271691	0.7873
GRADF_03^2	-23.32730	29.28357	-0.796600	0.4304
GRADF_04^2	-5.010057	28.17521	-0.177818	0.8598
GRADF_05^2	-23.96528	29.78140	-0.804707	0.4257
GRADF_06^2	0.390914	26.89336	0.014536	0.9885
GRADF_07^2	-17.64013	24.05195	-0.733418	0.4676
GRADF_09^2	-0.021593	0.017036	-1.267522	0.2123
GRADF_10^2	0.023621	0.035537	0.664683	0.5101
GRADF_11^2	-0.009392	0.035940	-0.261317	0.7952

R-squared	0.242595	Mean dependent var	32.29602
Adjusted R-squared	0.053244	S.D. dependent var	56.87960
S.E. of regression	55.34463	Akaike info criterion	11.05346
Sum squared resid	122521.1	Schwarz criterion	11.47013
Log likelihood	-270.8633	Hannan-Quinn criter.	11.21268
F-statistic	1.281193	Durbin-Watson stat	2.163330
Prob(F-statistic)	0.273534		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2015M01</td><td>1117.00</td><td>1111.57</td><td>5.42712</td><td>| . | *. |</td></tr>
<tr><td>2015M02</td><td>1118.00</td><td>1112.40</td><td>5.60315</td><td>| . | * |</td></tr>
<tr><td>2015M03</td><td>1125.00</td><td>1122.23</td><td>2.76960</td><td>| . | * . |</td></tr>
<tr><td>2015M04</td><td>1144.00</td><td>1135.74</td><td>8.25945</td><td>| . | .* |</td></tr>
<tr><td>2015M05</td><td>1164.00</td><td>1154.86</td><td>9.14081</td><td>| . | . * |</td></tr>
<tr><td>2015M06</td><td>1160.00</td><td>1161.09</td><td>-1.09221</td><td>| . *| . |</td></tr>
<tr><td>2015M07</td><td>1153.00</td><td>1154.76</td><td>-1.76487</td><td>| . *| . |</td></tr>
<tr><td>2015M08</td><td>1136.00</td><td>1147.63</td><td>-11.6281</td><td>| * . | . |</td></tr>
<tr><td>2015M09</td><td>1123.00</td><td>1129.59</td><td>-6.59269</td><td>| * | . |</td></tr>
<tr><td>2015M10</td><td>1101.00</td><td>1098.61</td><td>2.39183</td><td>| . | * . |</td></tr>
<tr><td>2015M11</td><td>1091.00</td><td>1085.89</td><td>5.11236</td><td>| . | *. |</td></tr>
<tr><td>2015M12</td><td>1091.00</td><td>1091.68</td><td>-0.67893</td><td>| . * . |</td></tr>
<tr><td>2016M01</td><td>1089.00</td><td>1091.33</td><td>-2.33024</td><td>| . *| . |</td></tr>
<tr><td>2016M02</td><td>1085.00</td><td>1084.89</td><td>0.11367</td><td>| . * . |</td></tr>
<tr><td>2016M03</td><td>1097.00</td><td>1090.95</td><td>6.04519</td><td>| . | * |</td></tr>
<tr><td>2016M04</td><td>1113.00</td><td>1111.60</td><td>1.40143</td><td>| . |* . |</td></tr>
<tr><td>2016M05</td><td>1127.00</td><td>1125.92</td><td>1.08119</td><td>| . |* . |</td></tr>
<tr><td>2016M06</td><td>1127.00</td><td>1125.92</td><td>1.07643</td><td>| . |* . |</td></tr>
<tr><td>2016M07</td><td>1118.00</td><td>1125.82</td><td>-7.82135</td><td>| *. | . |</td></tr>
<tr><td>2016M08</td><td>1115.00</td><td>1115.31</td><td>-0.31292</td><td>| . * . |</td></tr>
<tr><td>2016M09</td><td>1115.00</td><td>1114.14</td><td>0.85782</td><td>| . |* . |</td></tr>
<tr><td>2016M10</td><td>1085.00</td><td>1094.71</td><td>-9.70884</td><td>| * . | . |</td></tr>
<tr><td>2016M11</td><td>1084.00</td><td>1069.28</td><td>14.7211</td><td>| . | . * |</td></tr>
<tr><td>2016M12</td><td>1090.00</td><td>1087.65</td><td>2.34839</td><td>| . |* . |</td></tr>
<tr><td>2017M01</td><td>1094.00</td><td>1091.98</td><td>2.02353</td><td>| . |* . |</td></tr>
<tr><td>2017M02</td><td>1092.00</td><td>1090.98</td><td>1.01654</td><td>| . |* . |</td></tr>
<tr><td>2017M03</td><td>1097.00</td><td>1097.83</td><td>-0.83244</td><td>| . *| . |</td></tr>
<tr><td>2017M04</td><td>1105.00</td><td>1109.78</td><td>-4.78474</td><td>| .* | . |</td></tr>
<tr><td>2017M05</td><td>1113.00</td><td>1116.58</td><td>-3.57798</td><td>| . * | . |</td></tr>
<tr><td>2017M06</td><td>1115.00</td><td>1111.65</td><td>3.34993</td><td>| . | * . |</td></tr>
<tr><td>2017M07</td><td>1116.00</td><td>1115.44</td><td>0.56223</td><td>| . * . |</td></tr>
<tr><td>2017M08</td><td>1113.00</td><td>1116.09</td><td>-3.08714</td><td>| . * | . |</td></tr>
<tr><td>2017M09</td><td>1107.00</td><td>1112.33</td><td>-5.32521</td><td>| .* | . |</td></tr>
<tr><td>2017M10</td><td>1096.00</td><td>1085.89</td><td>10.1138</td><td>| . | . * |</td></tr>
<tr><td>2017M11</td><td>1075.00</td><td>1084.20</td><td>-9.19552</td><td>| * . | . |</td></tr>
<tr><td>2017M12</td><td>1076.00</td><td>1074.29</td><td>1.70713</td><td>| . |* . |</td></tr>
<tr><td>2018M01</td><td>1077.00</td><td>1077.96</td><td>-0.96209</td><td>| . *| . |</td></tr>
<tr><td>2018M02</td><td>1074.00</td><td>1074.76</td><td>-0.76187</td><td>| . * . |</td></tr>
<tr><td>2018M03</td><td>1082.00</td><td>1081.22</td><td>0.77940</td><td>| . * . |</td></tr>
<tr><td>2018M04</td><td>1097.00</td><td>1096.93</td><td>0.06518</td><td>| . * . |</td></tr>
<tr><td>2018M05</td><td>1109.00</td><td>1111.12</td><td>-2.12393</td><td>| . *| . |</td></tr>
<tr><td>2018M06</td><td>1107.00</td><td>1109.05</td><td>-2.05260</td><td>| . *| . |</td></tr>
<tr><td>2018M07</td><td>1096.00</td><td>1107.13</td><td>-11.1334</td><td>| * . | . |</td></tr>
<tr><td>2018M08</td><td>1093.00</td><td>1094.81</td><td>-1.80801</td><td>| . *| . |</td></tr>
<tr><td>2018M09</td><td>1111.00</td><td>1094.16</td><td>16.8445</td><td>| . | . *</td></tr>
<tr><td>2018M10</td><td>1148.00</td><td>1148.43</td><td>-0.43323</td><td>| . * . |</td></tr>
<tr><td>2018M11</td><td>1128.00</td><td>1135.92</td><td>-7.92093</td><td>| *. | . |</td></tr>
<tr><td>2018M12</td><td>1128.00</td><td>1128.26</td><td>-0.25504</td><td>| . * . |</td></tr>
<tr><td>2019M01</td><td>1130.00</td><td>1130.58</td><td>-0.57791</td><td>| . * . |</td></tr>
<tr><td>2019M02</td><td>1127.00</td><td>1128.88</td><td>-1.88478</td><td>| . *| . |</td></tr>
<tr><td>2019M03</td><td>1131.00</td><td>1135.16</td><td>-4.16477</td><td>| .* | . |</td></tr>
</table>

DG 19-126
Hearing Exhibit 2

Date: 06/30/19 Time: 11:41
Sample: 2014M11 2042M10
Included observations: 51
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	0.005	0.005	0.0014	
.*| . |	.*| . |	2	-0.161	-0.161	1.4389	
. | . |	. | . |	3	-0.019	-0.018	1.4597	0.227
.*| . |	.*| . |	4	-0.101	-0.131	2.0511	0.359
.*| . |	.*| . |	5	-0.087	-0.097	2.5006	0.475
. | . |	.*| . |	6	-0.032	-0.077	2.5615	0.634
. | . |	.*| . |	7	-0.044	-0.089	2.6790	0.749
. | . |	. | . |	8	0.048	0.007	2.8226	0.831
. | . |	.*| . |	9	-0.012	-0.066	2.8320	0.900
. | . |	. | . |	10	-0.008	-0.027	2.8358	0.944
. |** |	. |** |	11	0.251	0.228	7.1048	0.626
.*| . |	.*| . |	12	-0.117	-0.141	8.0611	0.623

HLF Customer Segment - Use Per Customer Model

Dependent Variable: HLF_UPC
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 05/14/19 Time: 08:44
Sample (adjusted): 2015M02 2019M03
Included observations: 50 after adjustments
Convergence achieved after 6 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BC_APR	0.313021	0.077073	4.061365	0.0002
BC_DEC	0.368064	0.070548	5.217191	0.0000
BC_FEB	0.315718	0.049130	6.426210	0.0000
BC_JAN	0.456043	0.057750	7.896817	0.0000
BC_MAR	0.552916	0.056589	9.770747	0.0000
C	2295.783	75.50638	30.40516	0.0000
BC_NOV	0.493002	0.112918	4.366030	0.0001
BC_OCT	0.921242	0.269672	3.416153	0.0015
TREND	2.392004	1.700256	1.406849	0.1672
AR(3)	0.259087	0.150604	1.720323	0.0931

R-squared	0.802014	Mean dependent var	2621.922
Adjusted R-squared	0.757467	S.D. dependent var	256.0531
S.E. of regression	126.1003	Akaike info criterion	12.68889
Sum squared resid	636050.9	Schwarz criterion	13.07129
Log likelihood	-307.2222	Hannan-Quinn criter.	12.83451
F-statistic	18.00378	Durbin-Watson stat	2.270741
Prob(F-statistic)	0.000000		

Inverted AR Roots	.64	-.32+.55i	-.32-.55i

DG 19-126
Hearing Exhibit 2

Heteroskedasticity Test: White

F-statistic	0.691357	Prob. F(9,40)	0.7124
Obs*R-squared	6.730760	Prob. Chi-Square(9)	0.6651
Scaled explained SS	8.446583	Prob. Chi-Square(9)	0.4898

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 06/30/19 Time: 11:42
Sample: 2015M02 2019M03
Included observations: 50
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	23978.72	8499.174	2.821299	0.0074
GRADF_01^2	-0.022200	0.018711	-1.186498	0.2424
GRADF_02^2	-0.015658	0.015791	-0.991585	0.3274
GRADF_03^2	-0.000946	0.008005	-0.118199	0.9065
GRADF_04^2	-0.000204	0.009215	-0.022150	0.9824
GRADF_05^2	-0.014641	0.010598	-1.381521	0.1748
GRADF_07^2	-0.051280	0.039130	-1.310498	0.1975
GRADF_08^2	-0.263307	0.216220	-1.217773	0.2304
GRADF_09^2	-1.198864	5.735466	-0.209026	0.8355
GRADF_10^2	-0.164339	0.144476	-1.137486	0.2621

R-squared	0.134615	Mean dependent var	12721.02
Adjusted R-squared	-0.060096	S.D. dependent var	25447.34
S.E. of regression	26200.83	Akaike info criterion	23.36183
Sum squared resid	2.75E+10	Schwarz criterion	23.74423
Log likelihood	-574.0457	Hannan-Quinn criter.	23.50745
F-statistic	0.691357	Durbin-Watson stat	1.530826
Prob(F-statistic)	0.712367		

obs	Actual	Fitted	Residual	Residual Plot
2015M02	2699.25	2761.67	-62.4207	
2015M03	3030.95	3050.50	-19.5425	
2015M04	2604.48	2603.70	0.78226	
2015M05	2174.20	2310.86	-136.656	
2015M06	2387.99	2331.60	56.3899	
2015M07	2480.72	2340.63	140.091	
2015M08	2180.51	2305.13	-124.621	
2015M09	2387.55	2362.29	25.2521	
2015M10	2653.78	2649.73	4.05754	
2015M11	2620.94	2576.83	44.1140	
2015M12	2712.97	2647.59	65.3799	
2016M01	3062.57	2842.47	220.102	
2016M02	2963.86	2724.10	239.757	
2016M03	2917.23	2920.89	-3.65823	
2016M04	2665.52	2665.39	0.12219	
2016M05	2458.83	2432.09	26.7341	
2016M06	2316.81	2376.41	-59.6017	
2016M07	2190.59	2390.20	-199.611	
2016M08	2435.36	2400.14	35.2197	
2016M09	2398.78	2365.12	33.6581	
2016M10	2591.53	2572.79	18.7414	
2016M11	2670.47	2684.83	-14.3599	
2016M12	2687.42	2738.02	-50.5969	
2017M01	2802.93	2902.37	-99.4394	
2017M02	2587.78	2744.94	-157.161	
2017M03	2912.67	2951.54	-38.8760	
2017M04	2572.11	2640.87	-68.7609	
2017M05	2586.48	2357.97	228.505	
2017M06	1989.76	2387.90	-398.136	
2017M07	2545.98	2378.43	167.549	
2017M08	2431.22	2454.48	-23.2576	
2017M09	2249.62	2301.65	-52.0362	
2017M10	2646.26	2576.51	69.7489	
2017M11	2682.28	2661.64	20.6398	
2017M12	2820.69	2739.41	81.2775	
2018M01	2981.24	3124.46	-143.219	
2018M02	2735.79	2789.35	-53.5614	
2018M03	2882.20	2946.08	-63.8741	
2018M04	2752.58	2684.24	68.3368	
2018M05	2598.38	2415.29	183.085	
2018M06	2381.21	2415.88	-34.6712	
2018M07	2327.24	2442.07	-114.831	
2018M08	2551.83	2478.83	72.9927	
2018M09	2469.61	2424.34	45.2683	
2018M10	2647.89	2666.39	-18.5020	
2018M11	2815.27	2832.47	-17.2001	
2018M12	2742.14	2844.92	-102.778	
2019M01	3065.07	2976.42	88.6414	
2019M02	2959.74	2855.78	103.962	
2019M03	3065.83	3048.86	16.9650	

Date: 06/30/19 Time: 11:43
Sample: 2014M11 2042M10
Included observations: 50
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
.*| . |	.*| . |	1	-0.139	-0.139	1.0202	
. | . |	. | . |	2	0.030	0.011	1.0698	0.301
. | . |	. | . |	3	-0.009	-0.003	1.0740	0.585
. | . |	. | . |	4	-0.026	-0.028	1.1109	0.774
. | . |	. | . |	5	0.003	-0.004	1.1115	0.892
.*| . |	.*| . |	6	-0.081	-0.082	1.4982	0.913
. |*. |	. |*. |	7	0.154	0.135	2.9346	0.817
.*| . |	. | . |	8	-0.073	-0.034	3.2615	0.860
. | . |	. | . |	9	0.040	0.021	3.3614	0.910
.*| . |	.*| . |	10	-0.095	-0.093	3.9532	0.914
. | . |	. | . |	11	-0.008	-0.027	3.9577	0.949
.*| . |	.*| . |	12	-0.161	-0.178	5.7361	0.890

Design Day – Total Throughput Model

Dependent Variable: NH
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 06/05/19 Time: 10:22
Sample (adjusted): 4/03/2018 3/31/2019
Included observations: 363 after adjustments
Convergence achieved after 5 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD	516.5568	14.82430	34.84526	0.0000
EDD_50	195.0905	57.13141	3.414768	0.0007
EDD(-1)	125.2954	13.82467	9.063172	0.0000
NOV	1368.338	683.7489	2.001229	0.0461
DEC	1818.091	738.5226	2.461794	0.0143
JAN	3795.167	793.3373	4.783800	0.0000
FEB	3943.929	797.9486	4.942585	0.0000
MAR	1826.170	716.6228	2.548300	0.0113
WEEKDAY=1	9376.180	326.6511	28.70396	0.0000
WEEKDAY=2	11057.76	330.5021	33.45746	0.0000
WEEKDAY=3	11603.72	330.3215	35.12858	0.0000
WEEKDAY=4	11662.81	327.0534	35.66027	0.0000
WEEKDAY=5	11566.76	324.1389	35.68458	0.0000
WEEKDAY=6	10152.73	320.2216	31.70532	0.0000
WEEKDAY=7	9196.417	322.5042	28.51565	0.0000
AR(1)	0.489512	0.047086	10.39602	0.0000

R-squared	0.983638	Mean dependent var	24413.77
Adjusted R-squared	0.982930	S.D. dependent var	12675.17
S.E. of regression	1656.021	Akaike info criterion	17.70530
Sum squared resid	9.52E+08	Schwarz criterion	17.87695
Log likelihood	-3197.512	Hannan-Quinn criter.	17.77353
Durbin-Watson stat	1.976847		

Inverted AR Roots	.49

Design Day – Planning Load Model

Dependent Variable: NH_PL
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 06/05/19 Time: 10:32
Sample (adjusted): 4/03/2018 3/31/2019
Included observations: 363 after adjustments
Convergence achieved after 6 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EDD	469.9630	12.49451	37.61357	0.0000
EDD_50	217.8216	48.03993	4.534179	0.0000
EDD(-1)	118.0049	11.64242	10.13577	0.0000
NOV	1507.526	586.9442	2.568431	0.0106
DEC	2565.630	633.3709	4.050754	0.0001
JAN	4704.229	680.7295	6.910569	0.0000
FEB	3893.331	685.6430	5.678365	0.0000
MAR	2103.568	616.4666	3.412299	0.0007
WEEKDAY=1	4144.320	279.1056	14.84857	0.0000
WEEKDAY=2	4721.060	282.3784	16.71891	0.0000
WEEKDAY=3	5051.830	282.2273	17.89986	0.0000
WEEKDAY=4	5015.585	279.4237	17.94975	0.0000
WEEKDAY=5	5027.649	276.9850	18.15134	0.0000
WEEKDAY=6	4213.954	273.6110	15.40126	0.0000
WEEKDAY=7	3952.399	275.5273	14.34485	0.0000
AR(1)	0.503064	0.046639	10.78630	0.0000

R-squared	0.986785	Mean dependent var	17465.61
Adjusted R-squared	0.986214	S.D. dependent var	11880.57
S.E. of regression	1394.935	Akaike info criterion	17.36216
Sum squared resid	6.75E+08	Schwarz criterion	17.53381
Log likelihood	-3135.232	Hannan-Quinn criter.	17.43039
Durbin-Watson stat	2.011989		

Inverted AR Roots	.50

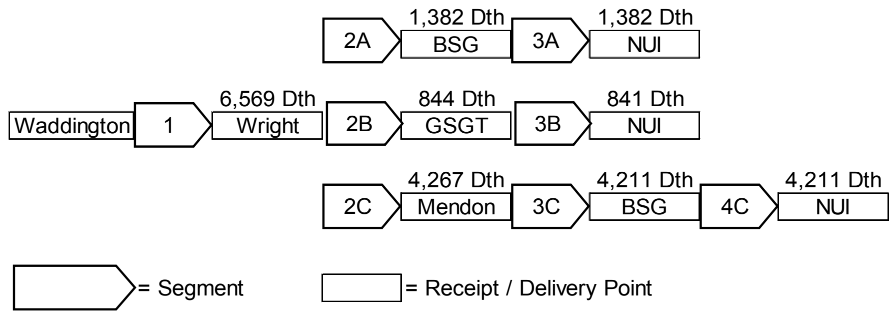
Northern Utilities, Inc.
Existing, Pending and Proposed Long-Term Portfolio Resources

November 1, 2022 Capacity Paths	Resource Type	Max Daily Quantity	Method of Assignment	Status
Iroquois Receipts Path	Pipeline	6,434	Company-managed	Existing
Tennessee Niagara Capacity	Pipeline	2,327	Capacity Release	Existing
Tennessee Long-haul Capacity	Pipeline	13,109	Capacity Release	Existing
Algonquin Receipts Path	Pipeline	1,251	Company-managed	Existing
Tennessee Firm Storage Capacity	Storage	2,644	Capacity Release	Existing
Dawn Storage Path	Storage	39,863	Capacity Release	Existing
Lewiston On-System LNG Plant	Peaking	6,500	Company-managed	Existing
Existing Long-Term Capacity		**72,128**		**Existing**
Portland XPress Project	Pipeline	9,965	Capacity Release	Pending
Atlantic Bridge Capacity	Pipeline	7,500	Capacity Release	Pending
Pending Long-Term Capacity		**89,593**		**Pending**
Westbrook XPress Project	Pipeline	9,965	Capacity Release	Proposed
Proposed Long-Term Capacity		**99,558**		**Proposed**

Northern Utilities, Inc.
Capacity Path: Iroquois Receipts Path
Source of Supply: Iroquois Receipts

Method of Assignment: Company-managed*

Capacity Path Diagram



Capacity Path Detail

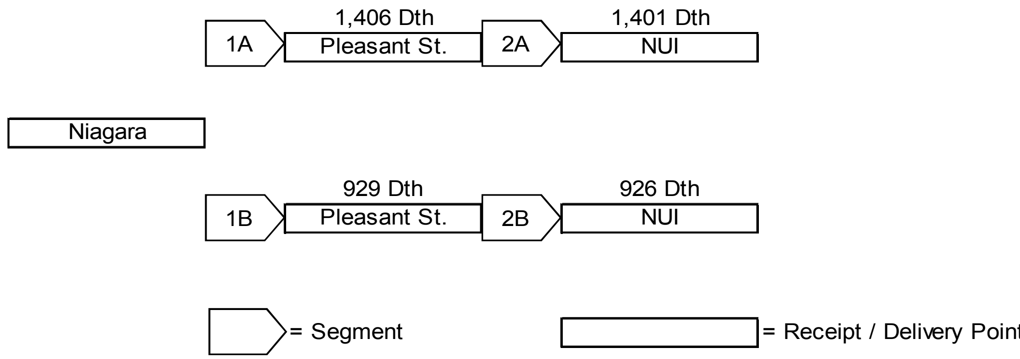
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Iroquois	R181001	RTS-1	10/31/2024	6,569	Dth	Year-Round	Waddington	Wright	Tennessee
2A	Transportation	Tennessee	95196	FT-A	10/31/2022	1,382	Dth	Year-Round	Wright	Bay State City Gate	
3A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
2B	Transportation	Tennessee	95196	FT-A	10/31/2022	844	Dth	Year-Round	Wright	Pleasant St.	Granite
3B	Transportation	Granite	16-100-FT-NN	FT-NN	10/31/2020	841	Dth	Year-Round	Granite	Northern City Gates	
2C	Transportation	Tennessee	41099	FT-A	10/31/2022	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
3C	Transportation	Algonquin	93200F	AFT-1	10/31/2020	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
4C	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				

* The contract quantities associated with the 844 Dth that feed into Granite are assigned via Capacity Release

Northern Utilities, Inc.
Capacity Path: Tennessee Niagara Capacity
Source of Supply: Niagara (Interconnection of TransCanada and Tennessee Pipelines)

Method of Assignment: Capacity Release

Capacity Path Diagram



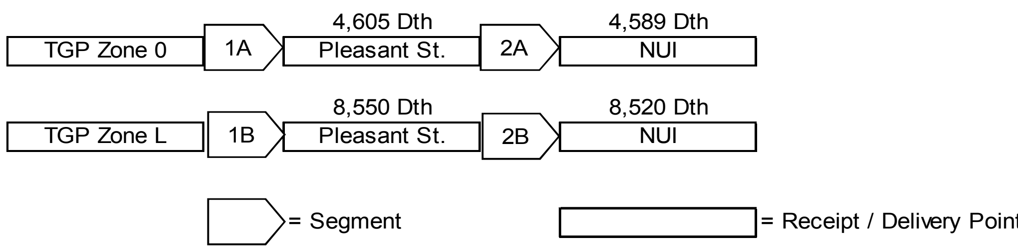
Capacity Path Detail

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	3/31/2025	1,406	Dth	Year-Round	Niagara	Pleasant St.	Granite
2A	Transportation	Granite	16-100-FT-NN	FT-NN	10/31/2020	1,401	Dth	Year-Round	Granite	Northern City Gates	
1B	Transportation	Tennessee	39735	FT-A	3/31/2025	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	Transportation	Granite	16-100-FT-NN	FT-NN	10/31/2020	926	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						2,327	Dth				

Northern Utilities, Inc.
Capacity Path: Tennessee Long-haul Capacity
Source of Supply: Tennessee Production Area

Method of Assignment: Capacity Release

Capacity Path Diagram



Capacity Path Detail

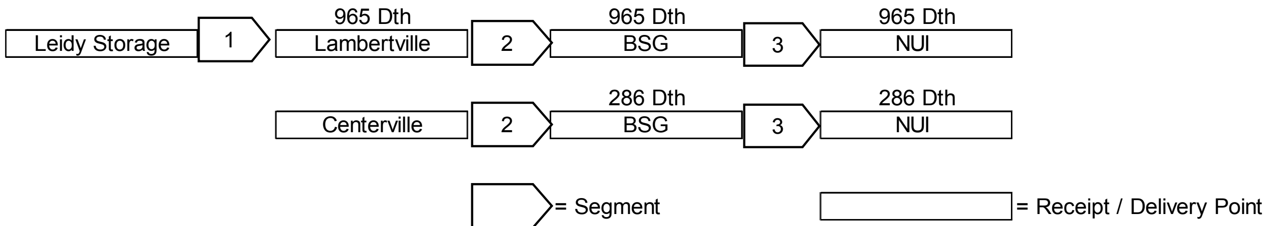
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5083	FT-A	10/31/2023	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	16-100-FT-NN	FT-NN	10/31/2020	4,589	Dth	Year-Round	Granite	Northern City Gates	
1B	Transportation	Tennessee	5083	FT-A	10/31/2023	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	16-100-FT-NN	FT-NN	10/31/2020	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: Algonquin Receipts Path
Source of Supply: Leidy Storage, Centerville

Method of Assignment: Company-managed

Capacity Path Diagram



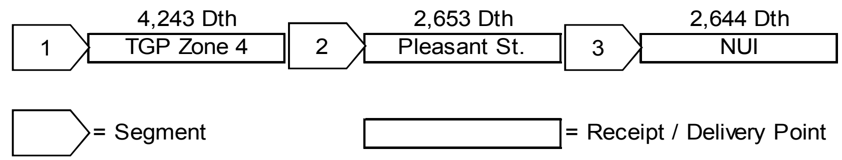
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Texas Eastern	800384	FT-1	10/31/2020	965	Dth	Year-Round	Leidy Storage	Lambertville	Algonquin
2	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2020	965	Dth	Year-Round	Lambertville (Texas Eastern)	Bay State City Gate	
2	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2020	286	Dth	Year-Round	Centerville (Transco, Zone 6, non-NY)	Bay State City Gate	
3	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: Tennessee Firm Storage Capacity
Source of Supply: Tennessee Firm Storage - Market Area

Method of Assignment: Capacity Release

Capacity Path Diagram



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	3/31/2025	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	3/31/2025	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	16-100-FT-NN	FT-NN	10/31/2020	2,644	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,644	Dth				

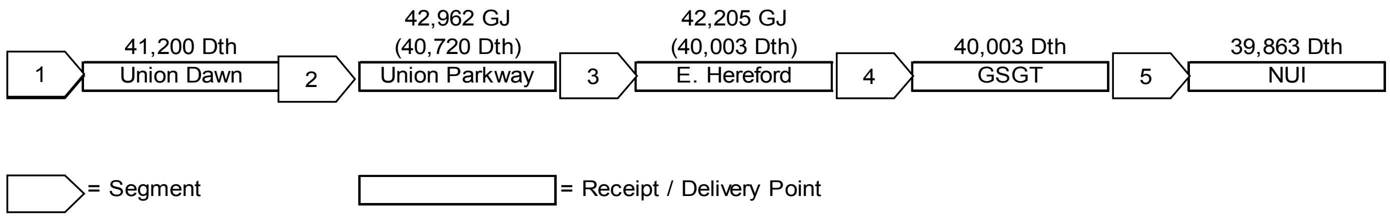
Note 1: Tennessee Contract No. 5195 has a maximum storage quantity of 259,337 Dth.

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: Dawn Storage Path
Source of Supply: Dawn Storage

Method of Assignment: Capacity Release

Capacity Path Diagram



Capacity Path Detail

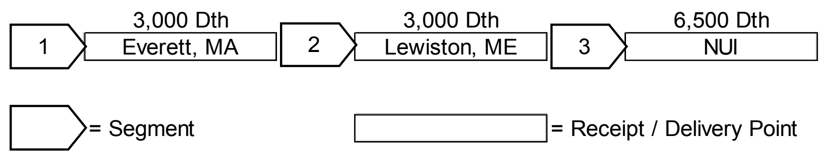
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Storage				3/31/2023	41,200	Dth	Year-Round	NA	Dawn	Union
2	Transportation	Union	M12256	M12	3/31/2033	42,962	GJ	Year-Round	Dawn	Parkway	TransCanada
3	Transportation	TransCanada	TBD	FT	3/31/2033	42,205	GJ	Year-Round	Parkway	East Hereford	PNGTS
4	Transportation	PNGTS	FTN-NUI-0001	FT	10/31/2032	40,003	Dth	Year-Round	Pittsburgh, NH	Granite	Granite
5	Transportation	Granite	16-100-FT-NN	FT-NN	10/31/2020	39,863	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						39,863	Dth				

Note 1: Dawn Storage Contract has an Maximum Storage Quantity equal to 4,000,000 Dth.

Northern Utilities, Inc.
Capacity Path: Lewiston On-System LNG Plant
Source of Supply: Lewiston LNG Plant Production

Method of Assignment: Company-managed

Capacity Path Diagram



Capacity Path Detail

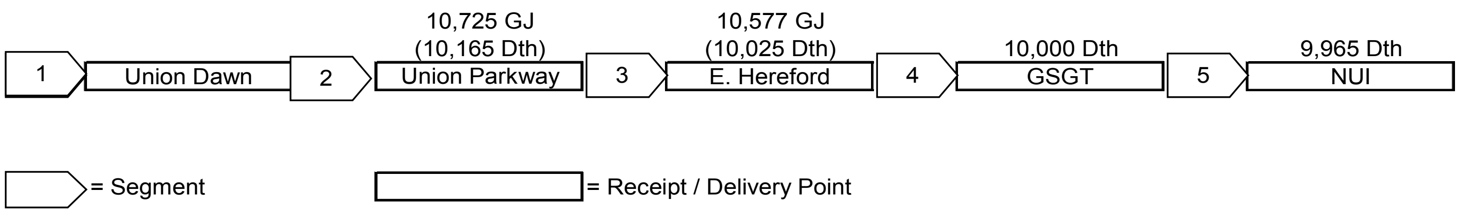
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	LNG Contract	Confidential	NA	NA	10/31/2019	3,000	Dth	Year-Round	NA	Everett, MA	NA
2	LNG Trucking Contract	Confidential	NA	NA	10/31/2019	3,000	Dth	Year-Round	Everett, MA	Lewiston, ME	NA
3	Lewiston LNG Plant	N/A	NA	NA	N/A	6,500	Dth	Year-Round	Lewiston, ME	Northern Distribution System	
Total Path Deliverable						6,500	Dth				

Note 1: The LNG Contract allows Northern to nominate up to 5,000 Dth per day with an annual maximum take is 125,000 Dth.

Northern Utilities, Inc.
Capacity Path: Portland Xpress Project
Source of Supply: Dawn Receipts

Method of Assignment: Capacity Release

Capacity Path Diagram



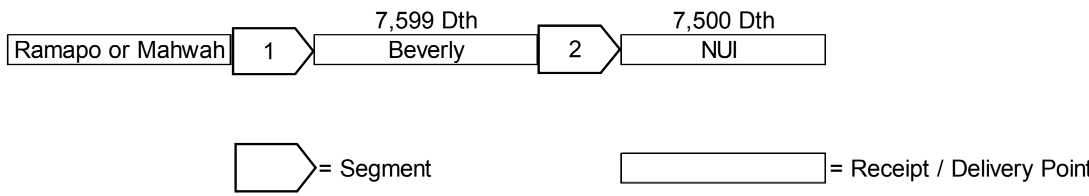
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Union	TBD	M12	10/31/2040	10,725	GJ	Year-Round	Dawn	Parkway	TransCanada
2	Transportation	TransCanada	TBD	FT	10/31/2040	10,577	GJ	Year-Round	Parkway	East Hereford	PNGTS
3	Transportation	PNGTS	TBD	FT - PXP	10/31/2040	10,000	Dth	Year-Round	Pittsburgh, NH	Granite	Granite
4	Transportation	Granite	16-100-FT-NN	FT-NN	10/31/2020	9,965	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						9,965	Dth				

Northern Utilities, Inc.
Capacity Path: Atlantic Bridge Capacity
Source of Supply: Ramapo (Millennium) or Mahwah (Tennessee)

Method of Assignment: Capacity Release

Capacity Path Diagram



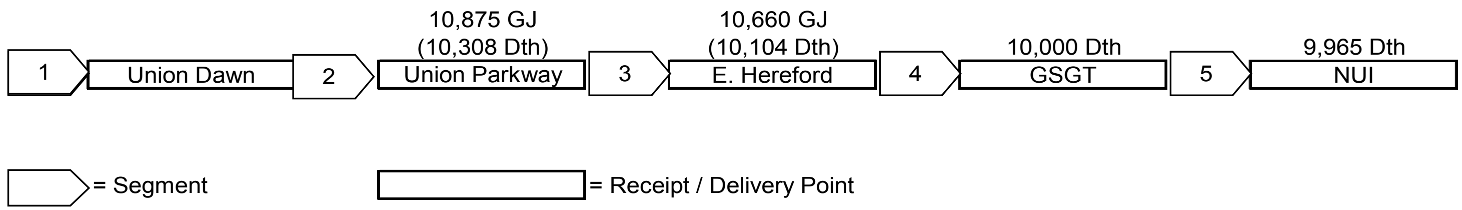
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Algonquin	TBD	AFT-1 [Atlantic Bridge Project]	TBD	7,599	Dth	Year-Round	Ramapo or Mahwah	Beverly	Maritimes
2	Transportation	Maritimes	TBD	MN365	TBD	7,500	Dth	Year-Round	Beverly	Lewiston	
Total Path Deliverable						7,500	Dth				

Northern Utilities, Inc.
Capacity Path: Westbrook Xpress Project
Source of Supply: Dawn Receipts

Method of Assignment: Capacity Release

Capacity Path Diagram



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	Union	TBD	M12	10/31/2037	10,875	GJ	Year-Round	Dawn	Parkway	TransCanada
2	Transportation	TransCanada	TBD	FT	10/31/2037	10,660	GJ	Year-Round	Parkway	East Hereford	PNGTS
3	Transportation	PNGTS	TBD	FT - PXP	10/31/2037	10,000	Dth	Year-Round	Pittsburgh, NH	Granite	Granite
4	Transportation	Granite	16-100-FT-NN	FT-NN	10/31/2020	9,965	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						9,965	Dth				

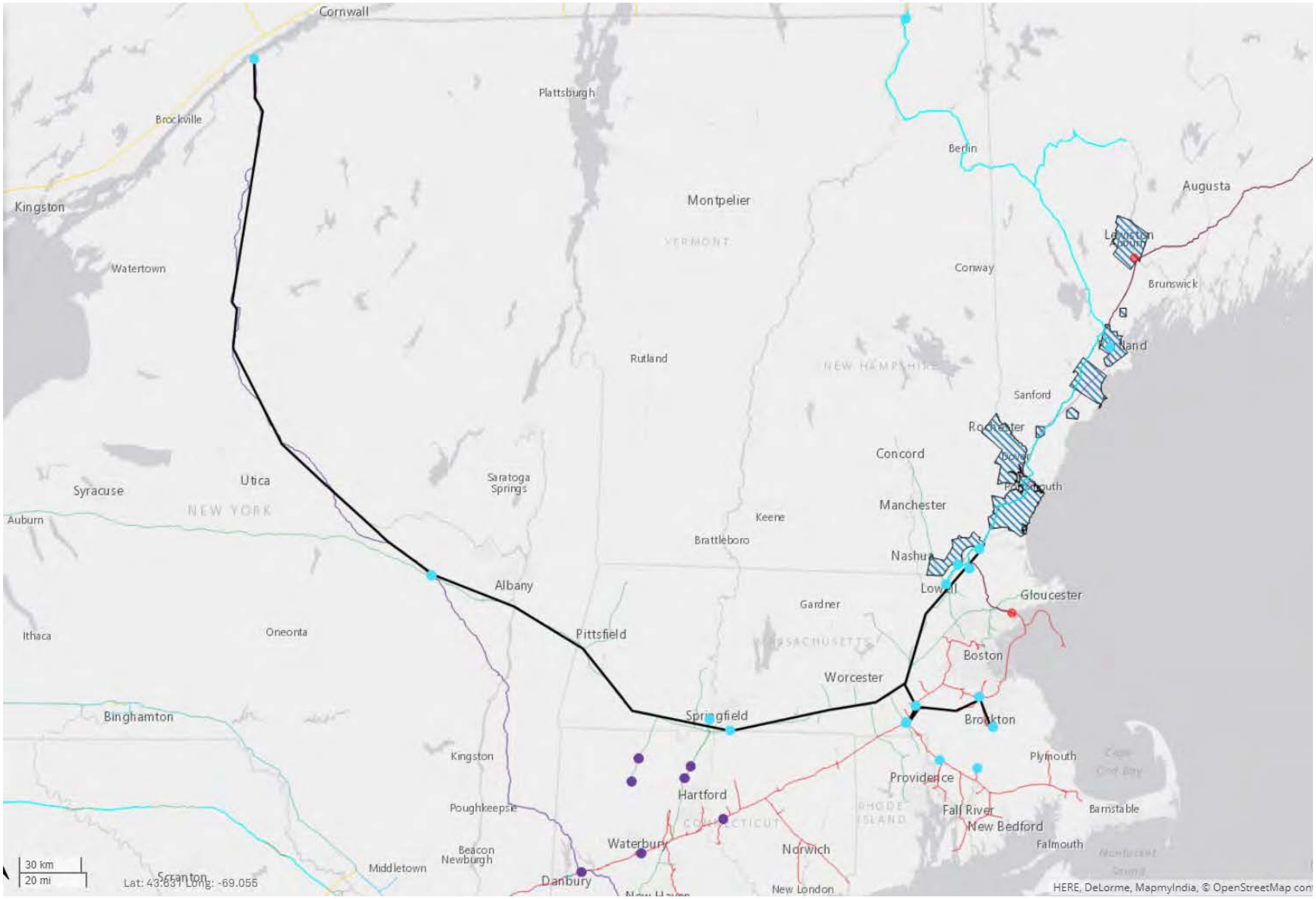
OUTLINE OF APPENDIX 3

Capacity Path Maps and Pipeline Maps

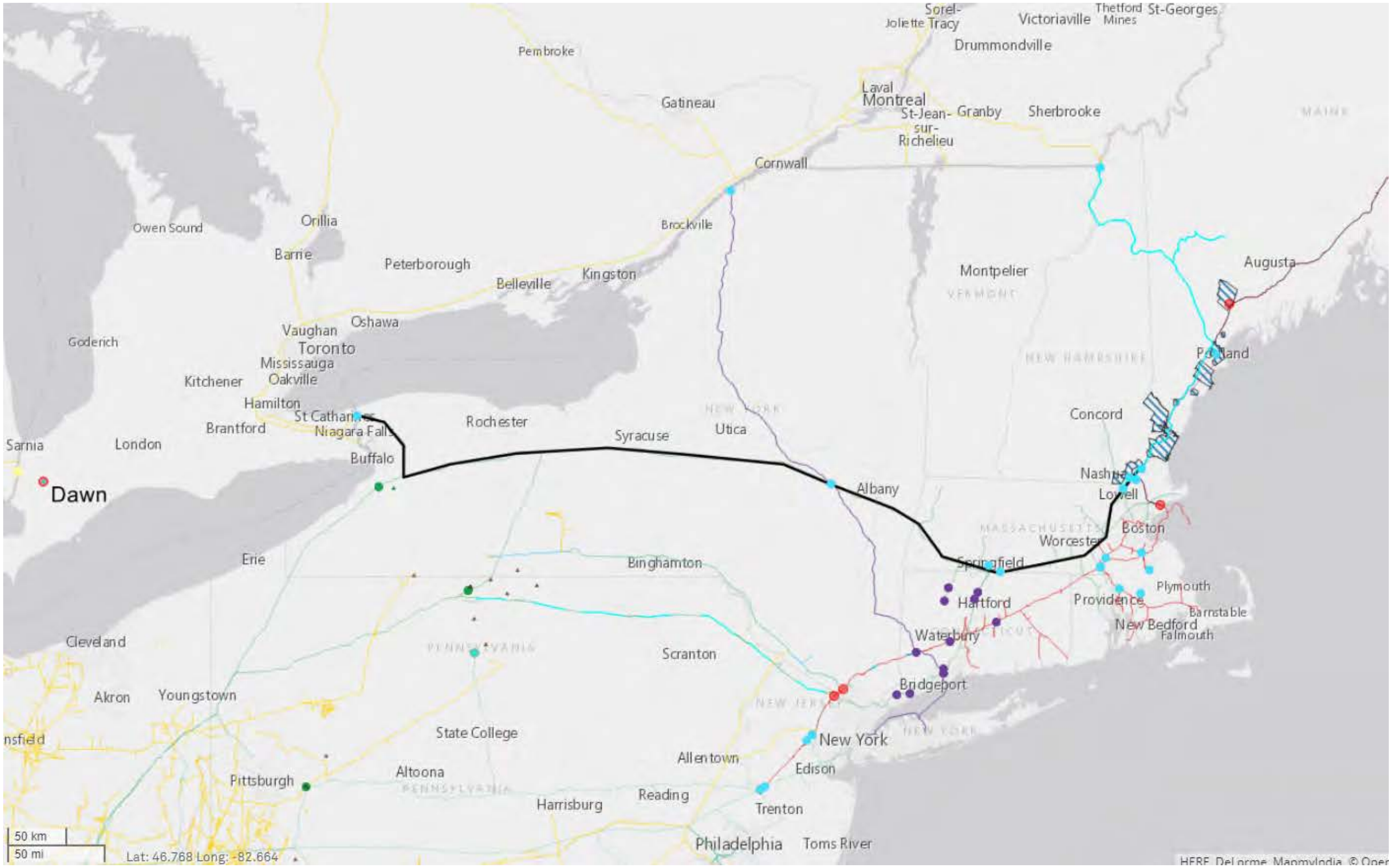
CAPACITY PATH MAPS

PIPELINE MAPS

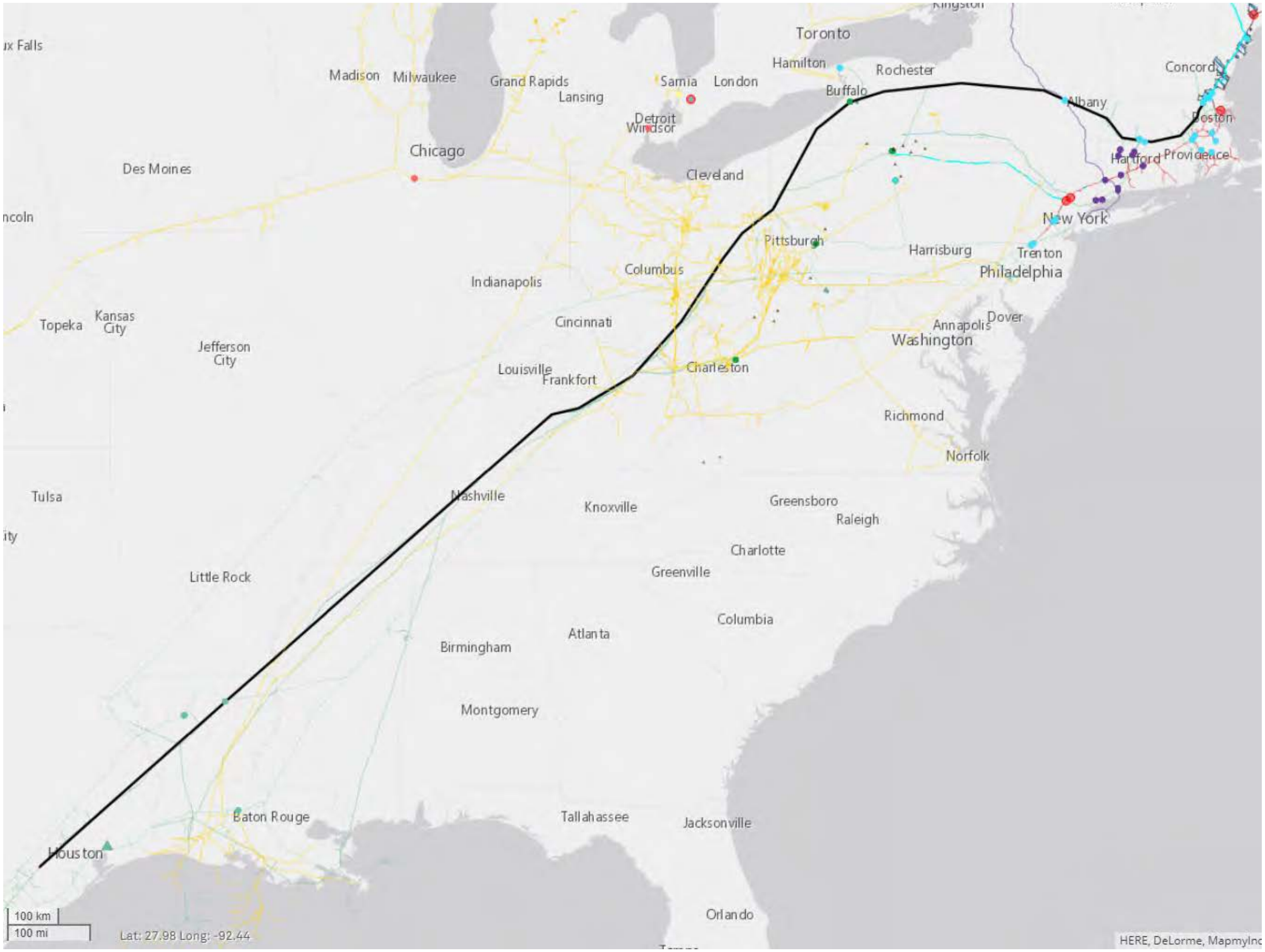
Iroquois Receipts Path



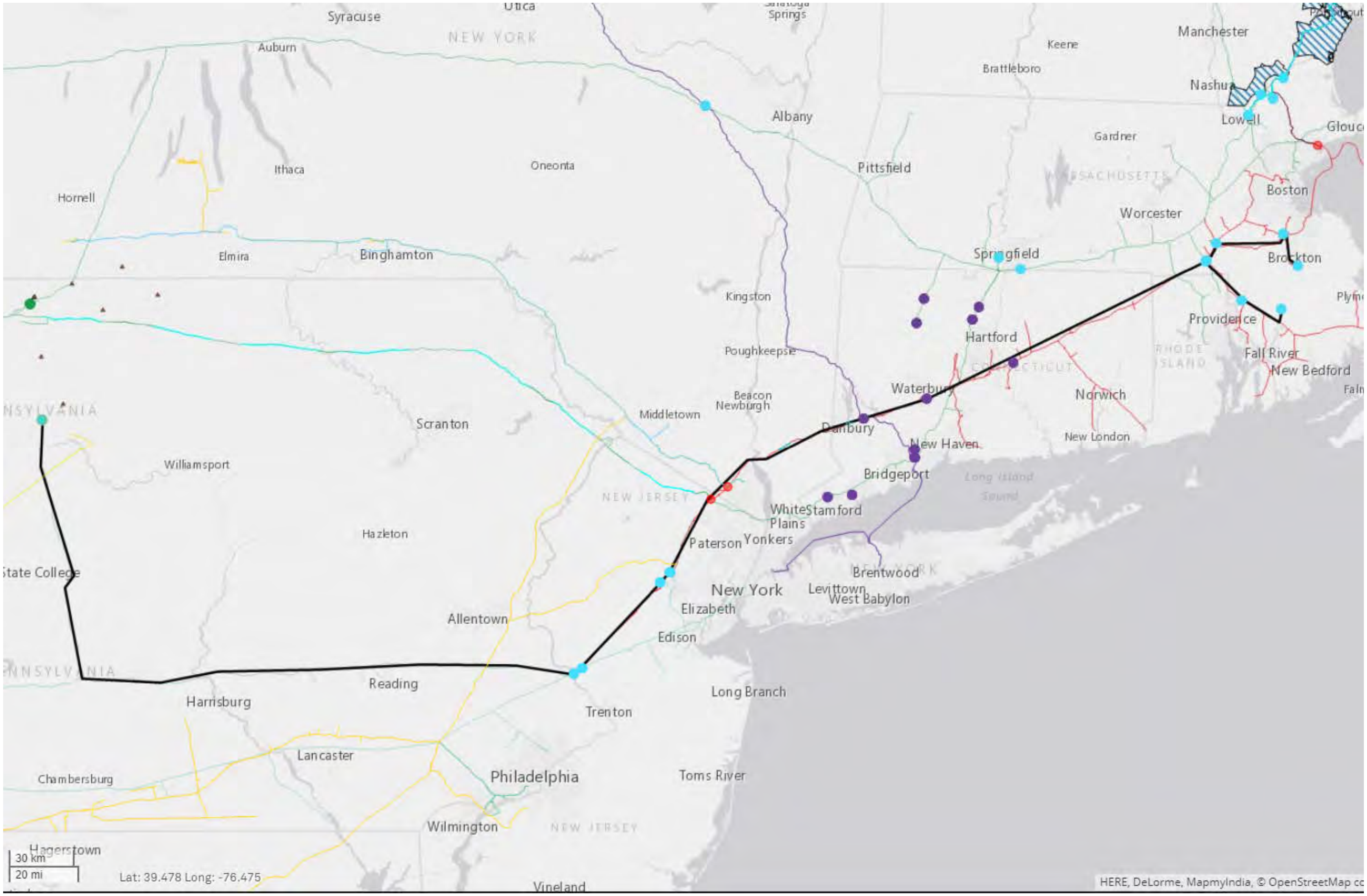
Tennessee Niagara Capacity



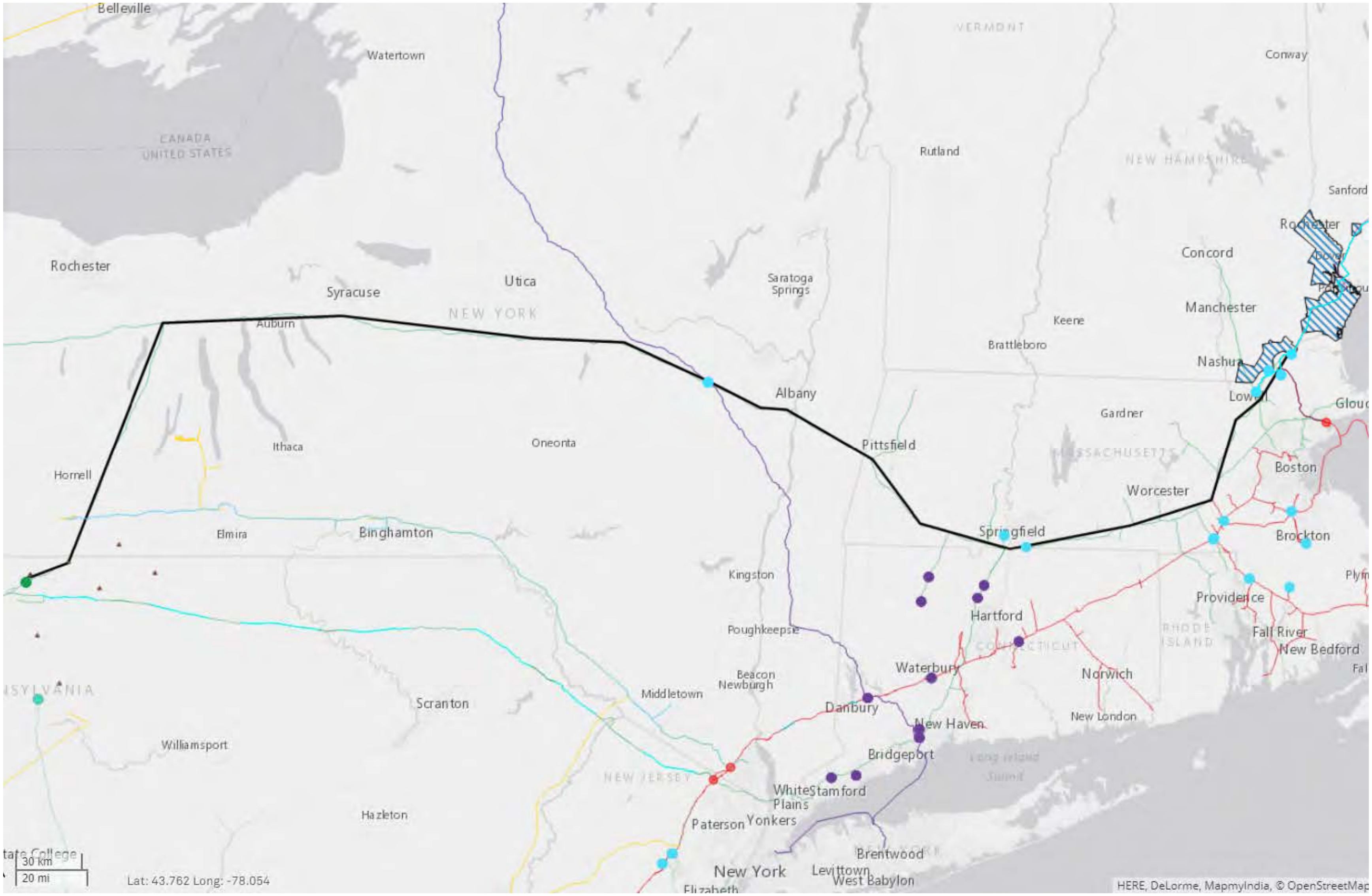
Tennessee Long-haul Capacity



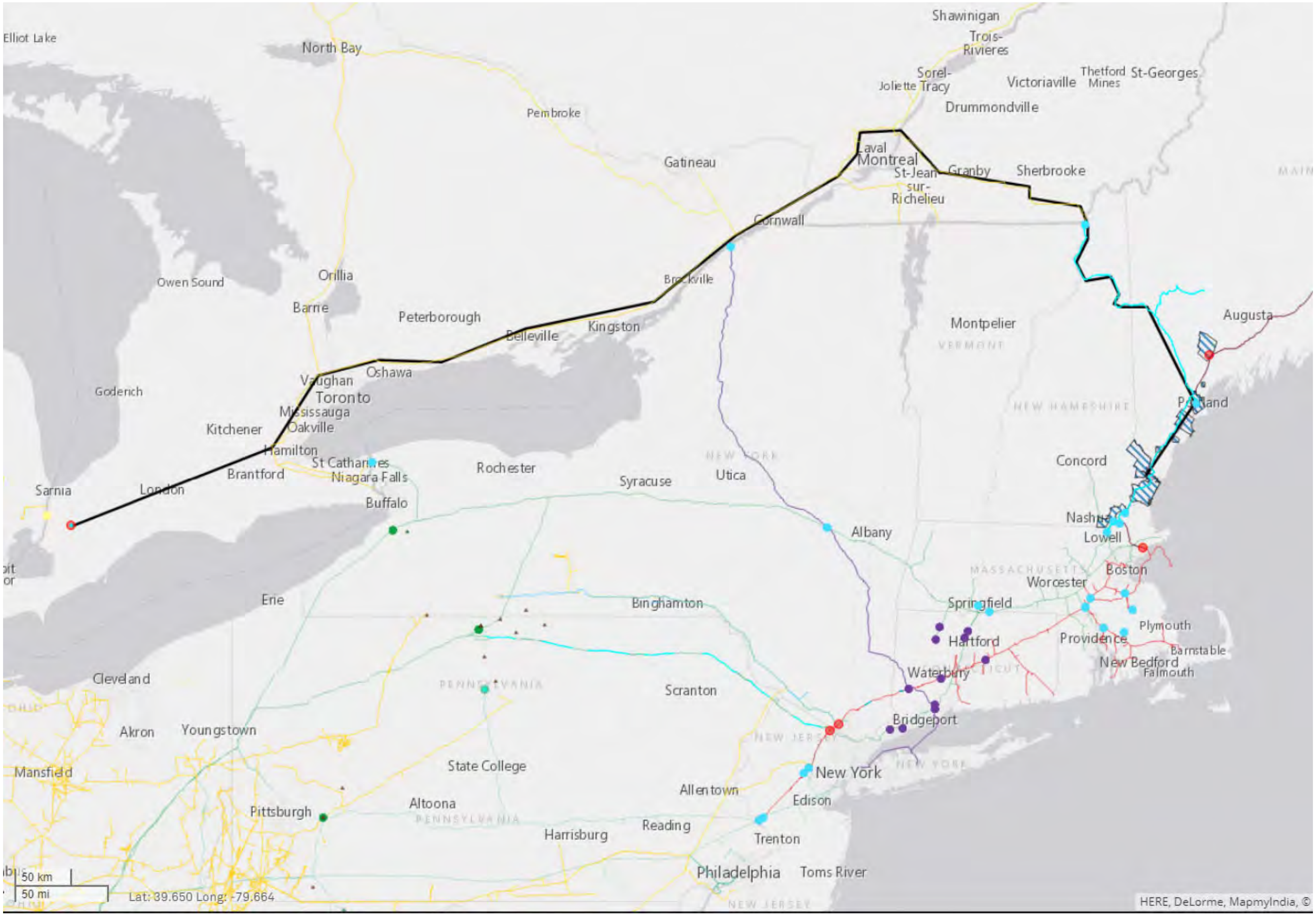
Algonquin Receipts Path



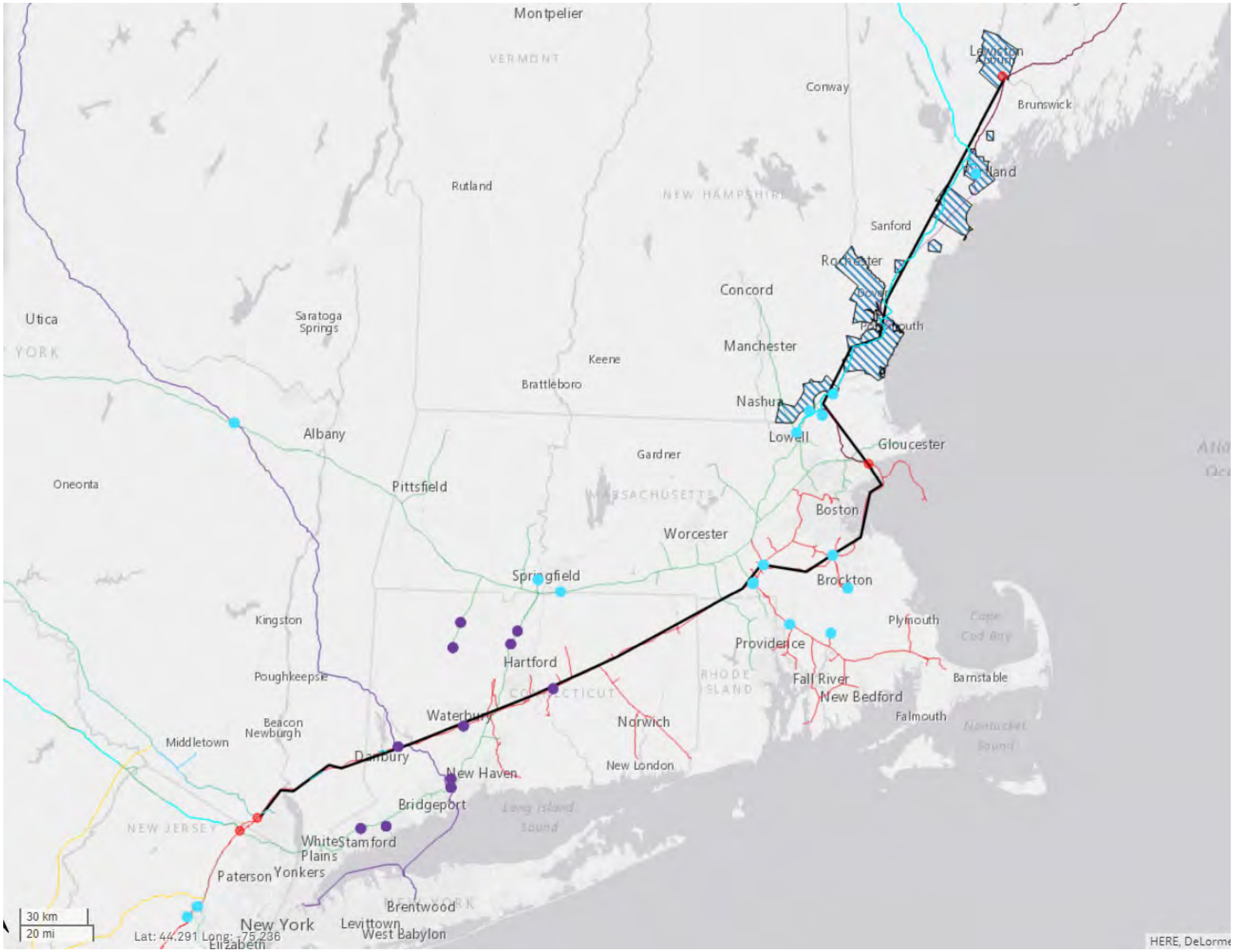
Tennessee Firm Storage Capacity

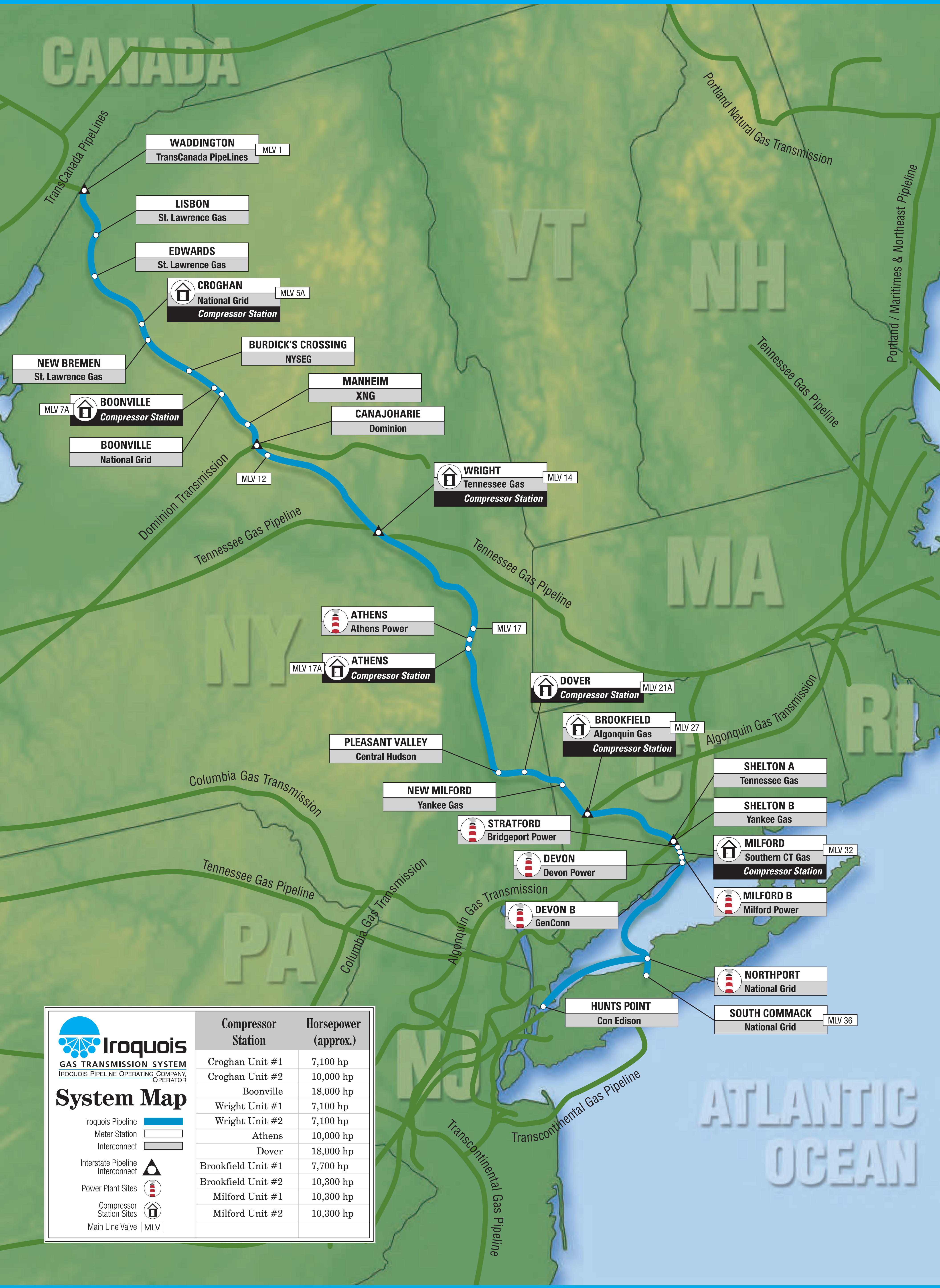


Dawn Storage Path, Portland Xpress Project, Westbrook Xpress Project

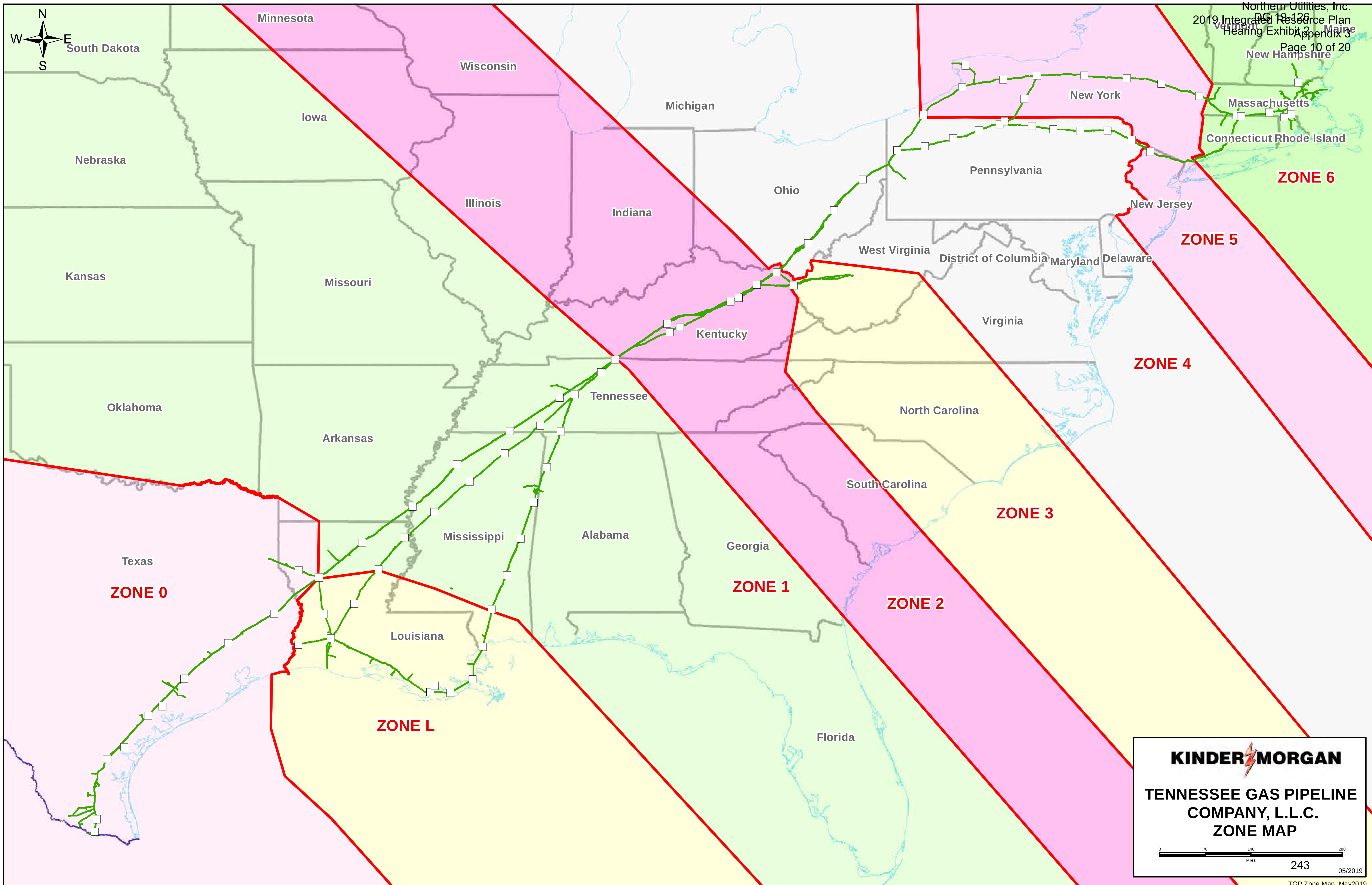


Atlantic Bridge Capacity





Compressor Station	Horsepower (approx.)
Croghan Unit #1	7,100 hp
Croghan Unit #2	10,000 hp
Boonville	18,000 hp
Wright Unit #1	7,100 hp
Wright Unit #2	7,100 hp
Athens	10,000 hp
Dover	18,000 hp
Brookfield Unit #1	7,700 hp
Brookfield Unit #2	10,300 hp
Milford Unit #1	10,300 hp
Milford Unit #2	10,300 hp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Minnesota
Wisconsin
Michigan
Vermont
Maine
New Hampshire
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Massachusetts
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Maryland
Delaware
Kentucky
Virginia
Oklahoma
Arkansas
Tennessee
North Carolina
South Carolina
Mississippi
Alabama
Georgia
Texas
Louisiana
Florida
ZONE 0
ZONE L
ZONE 1
ZONE 2
ZONE 3
ZONE 4
ZONE 5
ZONE 6
KINDER MORGAN
TENNESSEE GAS PIPELINE COMPANY, L.L.C.
ZONE MAP
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140
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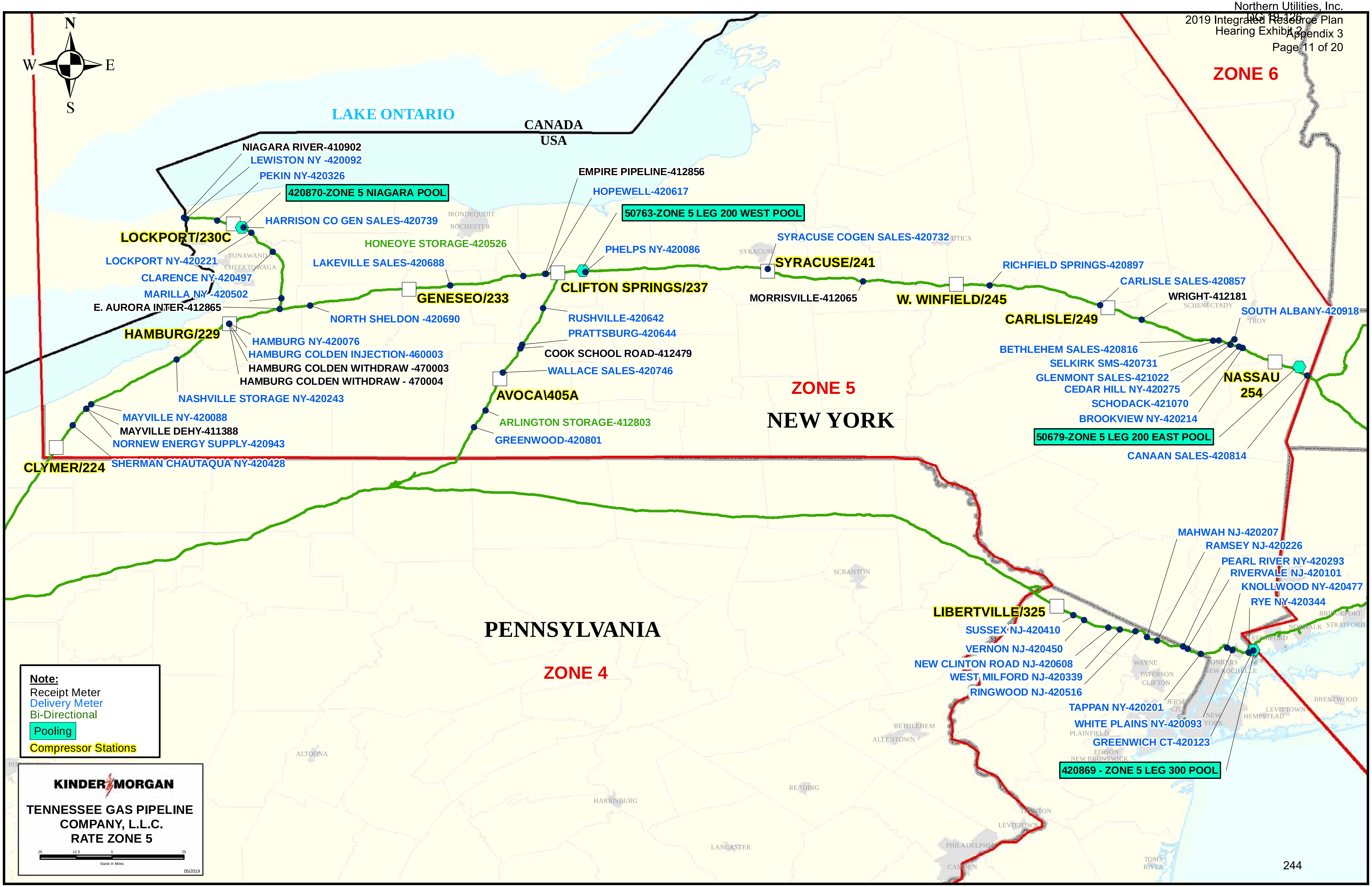
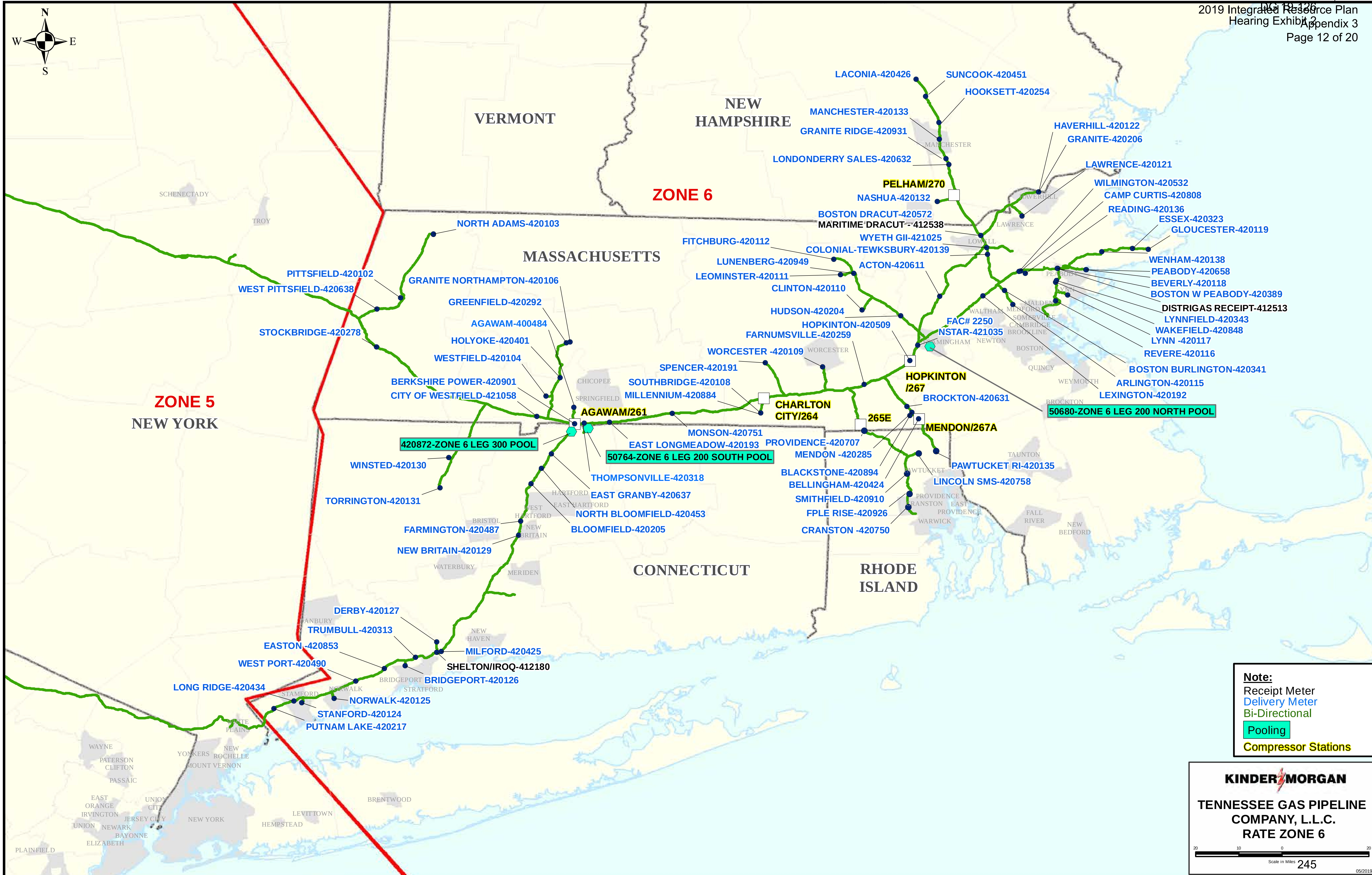
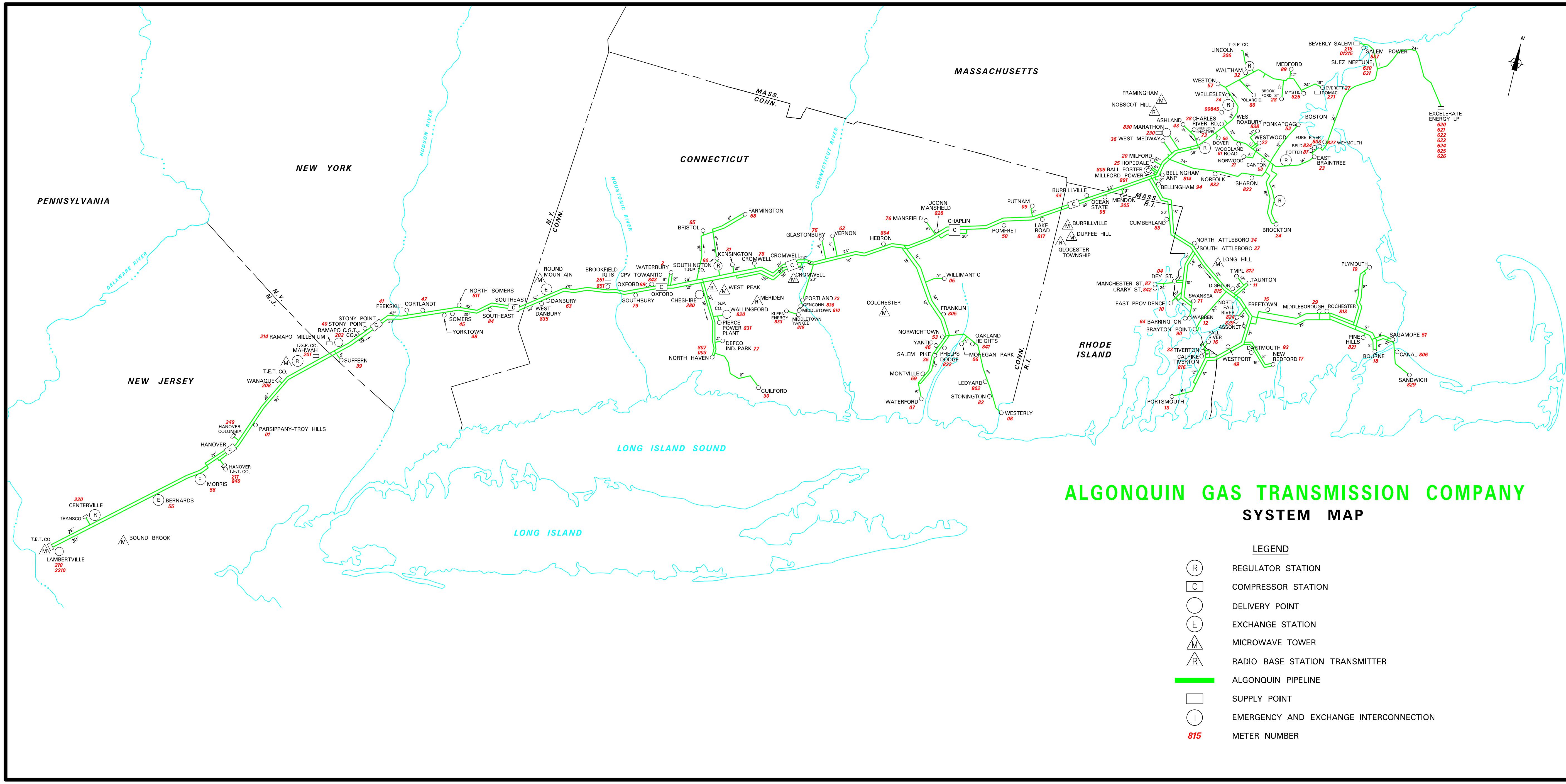
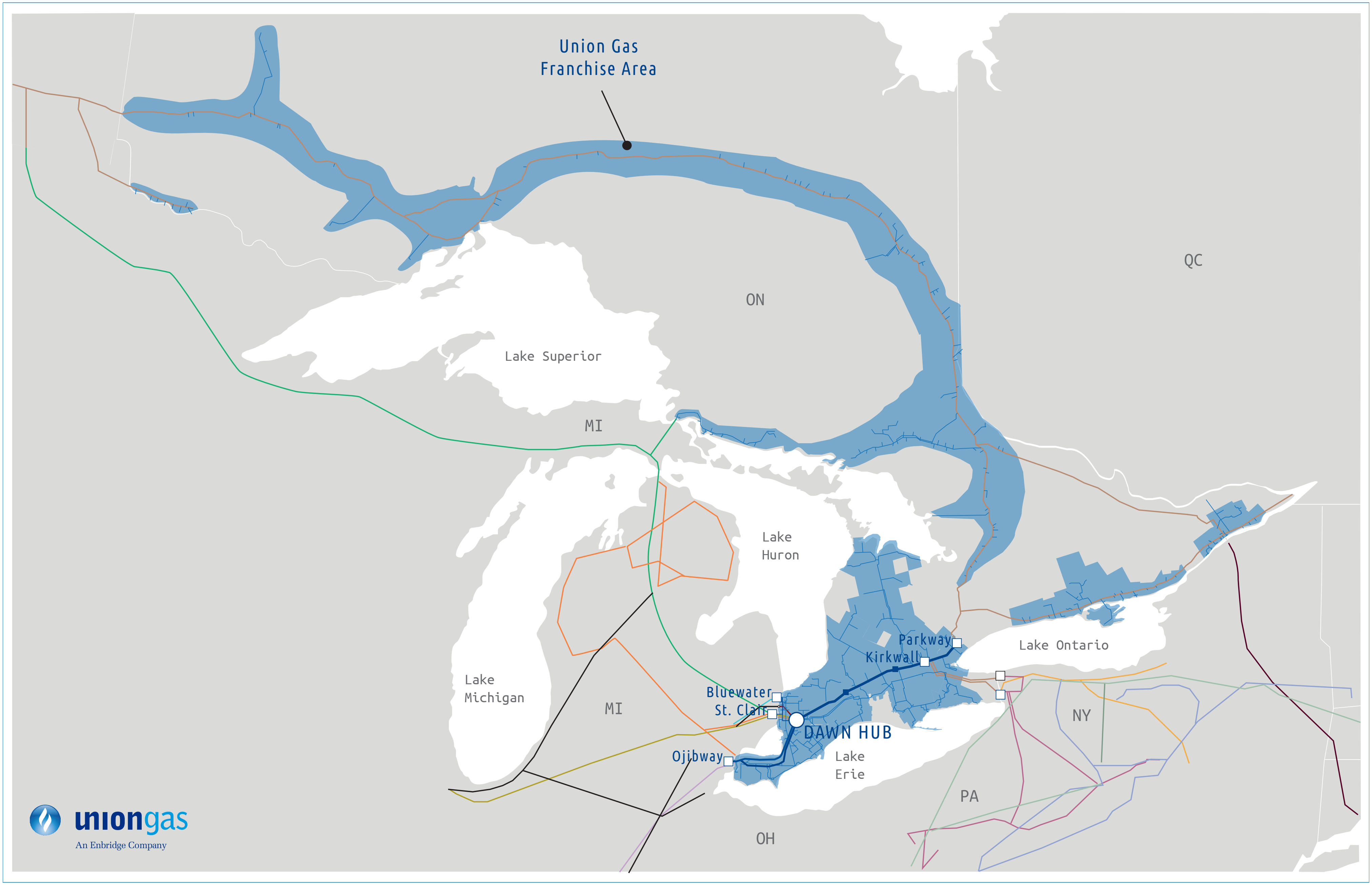
Miles
05/2019
TGP Zone Map_May2019


N
W
E
S
LAKE ONTARIO
CANADA
USA
NIAGARA RIVER-410902
LEWISTON NY -420092
PEKIN NY-420326
420870-ZONE 5 NIAGARA POOL
HARRISON CO GEN SALES-420739
LOCKPORT/230C
LOCKPORT NY-420221
CLARENCE NY-420497
MARILLA NY -420502
E. AURORA INTER-412865
HAMBURG/229
HAMBURG NY-420076
HAMBURG COLDEN INJECTION-460003
HAMBURG COLDEN WITHDRAW -470003
HAMBURG COLDEN WITHDRAW - 470004
NASHVILLE STORAGE NY-420243
MAYVILLE NY-420088
MAYVILLE DEHY-411388
NORNEW ENERGY SUPPLY-420943
SHERMAN CHAUTAQUA NY-420428
CLYMER/224
HONEOYE STORAGE-420526
LAKEVILLE SALES-420688
NORTH SHELDON -420690
GENESEO/233
EMPIRE PIPELINE-412856
HOPEWELL-420617
50763-ZONE 5 LEG 200 WEST POOL
PHELPS NY-420086
CLIFTON SPRINGS/237
RUSHVILLE-420642
PRATTSBURG-420644
COOK SCHOOL ROAD-412479
WALLACE SALES-420746
AVOCA\405A
ARLINGTON STORAGE-412803
GREENWOOD-420801
SYRACUSE COGEN SALES-420732
SYRACUSE/241
MORRISVILLE-412065
W. WINFIELD/245
RICHFIELD SPRINGS-420897
CARLISLE SALES-420857
WRIGHT-412181
CARLISLE/249
SOUTH ALBANY-420918
BETHLEHEM SALES-420816
SELKIRK SMS-420731
GLENMONT SALES-421022
CEDAR HILL NY-420275
SCHODACK-421070
BROOKVIEW NY-420214
NASSAU 254
50679-ZONE 5 LEG 200 EAST POOL
CANAAN SALES-420814
ZONE 6
ZONE 5
NEW YORK
PENNSYLVANIA
ZONE 4
MAHWAH NJ-420207
RAMSEY NJ-420226
PEARL RIVER NY-420293
RIVERVALE NJ-420101
KNOLLWOOD NY-420477
RYE NY-420344
LIBERTVILLE/325
SUSSEX NJ-420410
VERNON NJ-420450
NEW CLINTON ROAD NJ-420608
WEST MILFORD NJ-420339
RINGWOOD NJ-420516
TAPPAN NY-420201
WHITE PLAINS NY-420093
GREENWICH CT-420123
420869 - ZONE 5 LEG 300 POOL
Note:
Receipt Meter
Delivery Meter
Bi-Directional
Pooling
Compressor Stations
KINDER MORGAN
TENNESSEE GAS PIPELINE COMPANY, L.L.C.
RATE ZONE 5
05/2019
GISMS-4752_Zone 5



GISMS-4750_ Zone 6


ALGONQUIN GAS TRANSMISSION COMPANY
SYSTEM MAP
LEGEND
REGULATOR STATION
COMPRESSOR STATION
DELIVERY POINT
EXCHANGE STATION
MICROWAVE TOWER
RADIO BASE STATION TRANSMITTER
ALGONQUIN PIPELINE
SUPPLY POINT
EMERGENCY AND EXCHANGE INTERCONNECTION
815 METER NUMBER
PENNSYLVANIA
NEW YORK
NEW JERSEY
CONNECTICUT
MASSACHUSETTS
RHODE ISLAND
LONG ISLAND SOUND
LONG ISLAND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ON
QC
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MI
Lake
Huron
Lake Ontario
Parkway
Kirkwall
Bluewater
St. Clair
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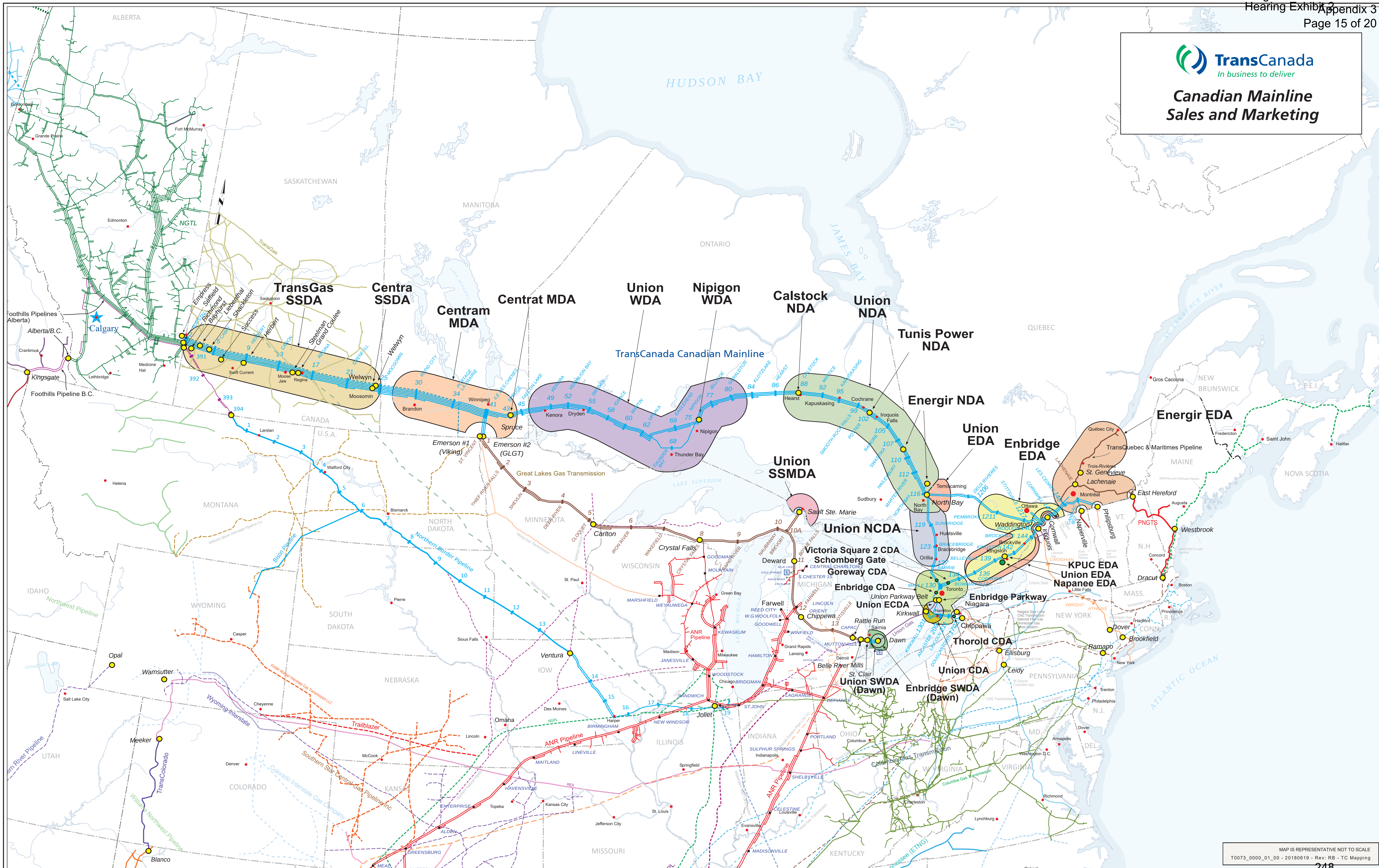
PA
OH
uniongas
An Enbridge Company


TransCanada
In business to deliver
Canadian Mainline
Sales and Marketing
TransCanada Canadian Mainline
TransGas SSDA
Centra SSDA
Centram MDA
Centrat MDA
Union WDA
Nipigon WDA
Calstock NDA
Union NDA
Tunis Power NDA
Energir NDA
Union EDA
Enbridge EDA
Energir EDA
Union SSMDA
Union NCDA
Victoria Square 2 CDA
Schomberg Gate
Goreway CDA
Enbridge CDA
Union Parkway Belt
Union ECDA
Enbridge Parkway
Thorold CDA
Union CDA
Union SWDA (Dawn)
Enbridge SWDA (Dawn)
KPUC EDA
Union EDA
Napanee EDA
HUDSON BAY
JAMES BAY
ALBERTA
SASKATCHEWAN
MANITOBA
ONTARIO
QUEBEC
NEW BRUNSWICK
NOVA SCOTIA
MAINE
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
MINNESOTA
WISCONSIN
MICHIGAN
IDAHO
WYOMING
NEBRASKA
IOWA
ILLINOIS
INDIANA
OHIO
PENNSYLVANIA
NEW YORK
UTAH
COLORADO
KANSAS
MISSOURI
KENTUCKY
VIRGINIA
ATLANTIC OCEAN
Calgary
Empress
Emerson #1 (Viking)
Emerson #2 (GLGT)
Great Lakes Gas Transmission
Northern Border Pipeline
Foothills Pipelines (Alberta)
Foothills Pipeline B.C.
Kingsgate
NGTL
ANR Pipeline
TransQuebec & Maritimes Pipeline
PNGTS
Westbrook
Dracut
Sault Ste. Marie
Dawn
Chippawa
Niagara
Iroquois
Waddington
Cornwall
Napierville
Philipsburg
East Hereford
St. Clair
Belle River Mills
Ventura
Joliet
Crystal Falls
Carlton
Deward
Farwell
Chippewa
Kirkwall
Ellisburg
Leidy
Dover
Brookfield
Ramapo
Opal
Wamsutter
Meeker
Blanco
MAP IS REPRESENTATIVE NOT TO SCALE
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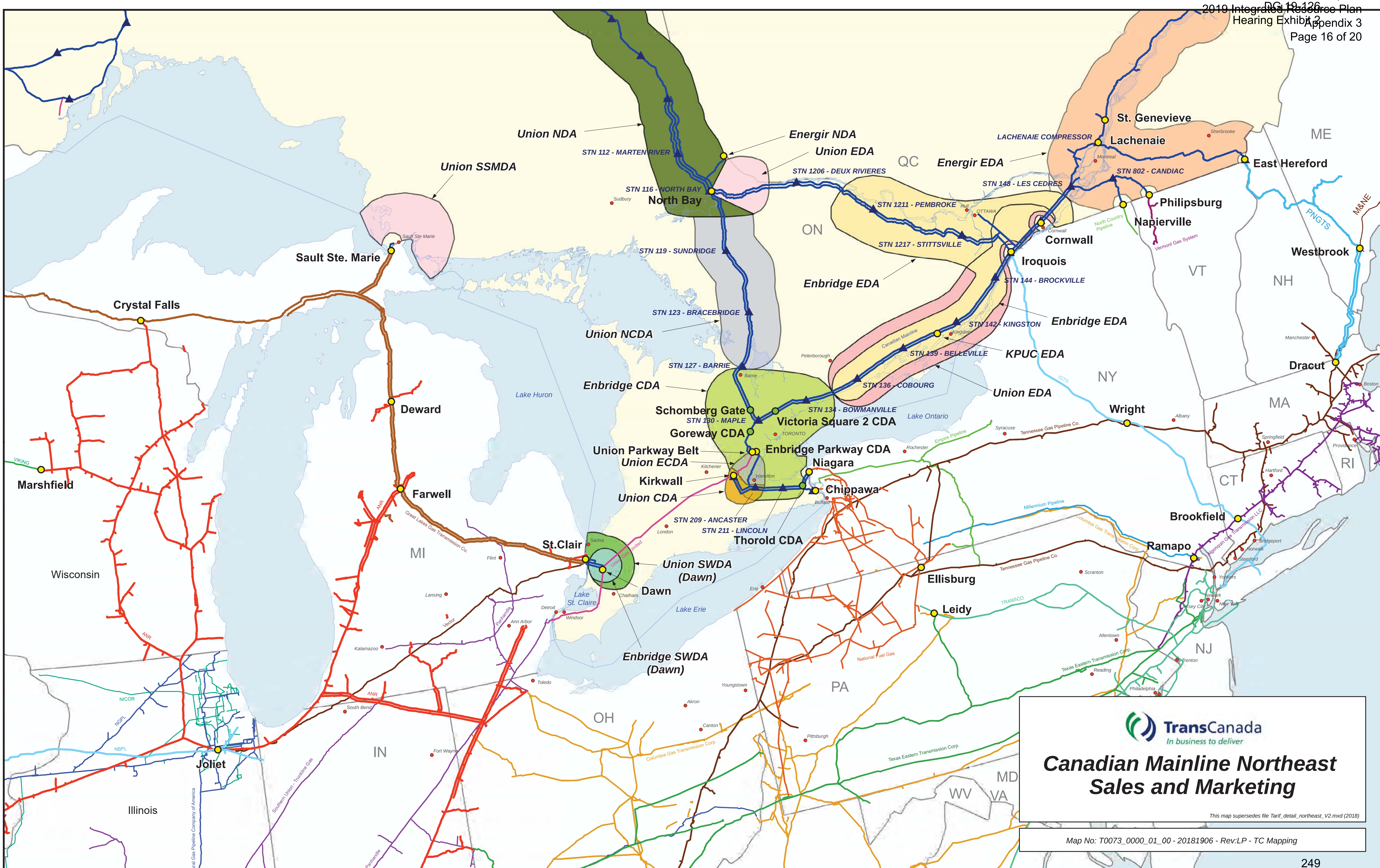
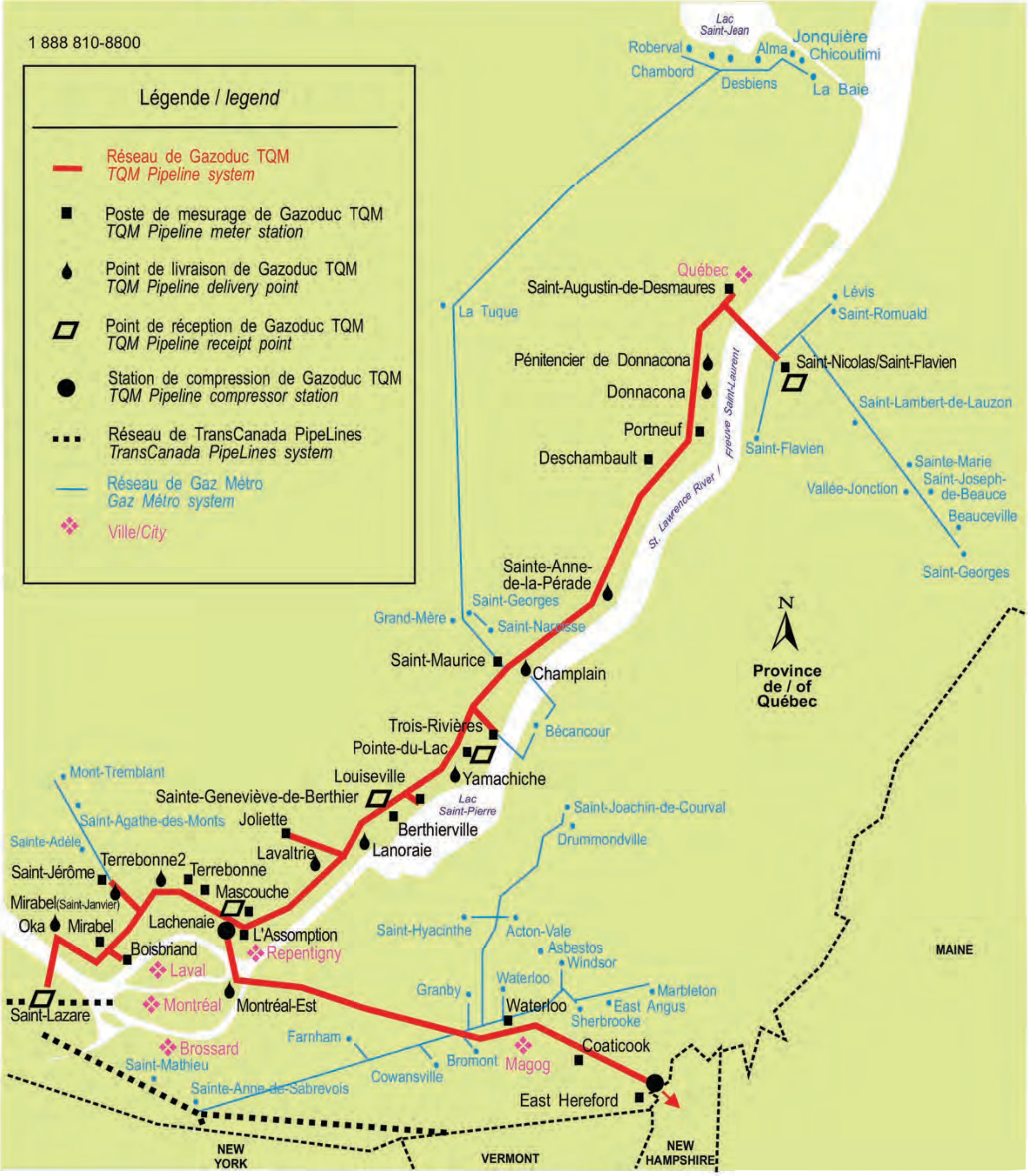
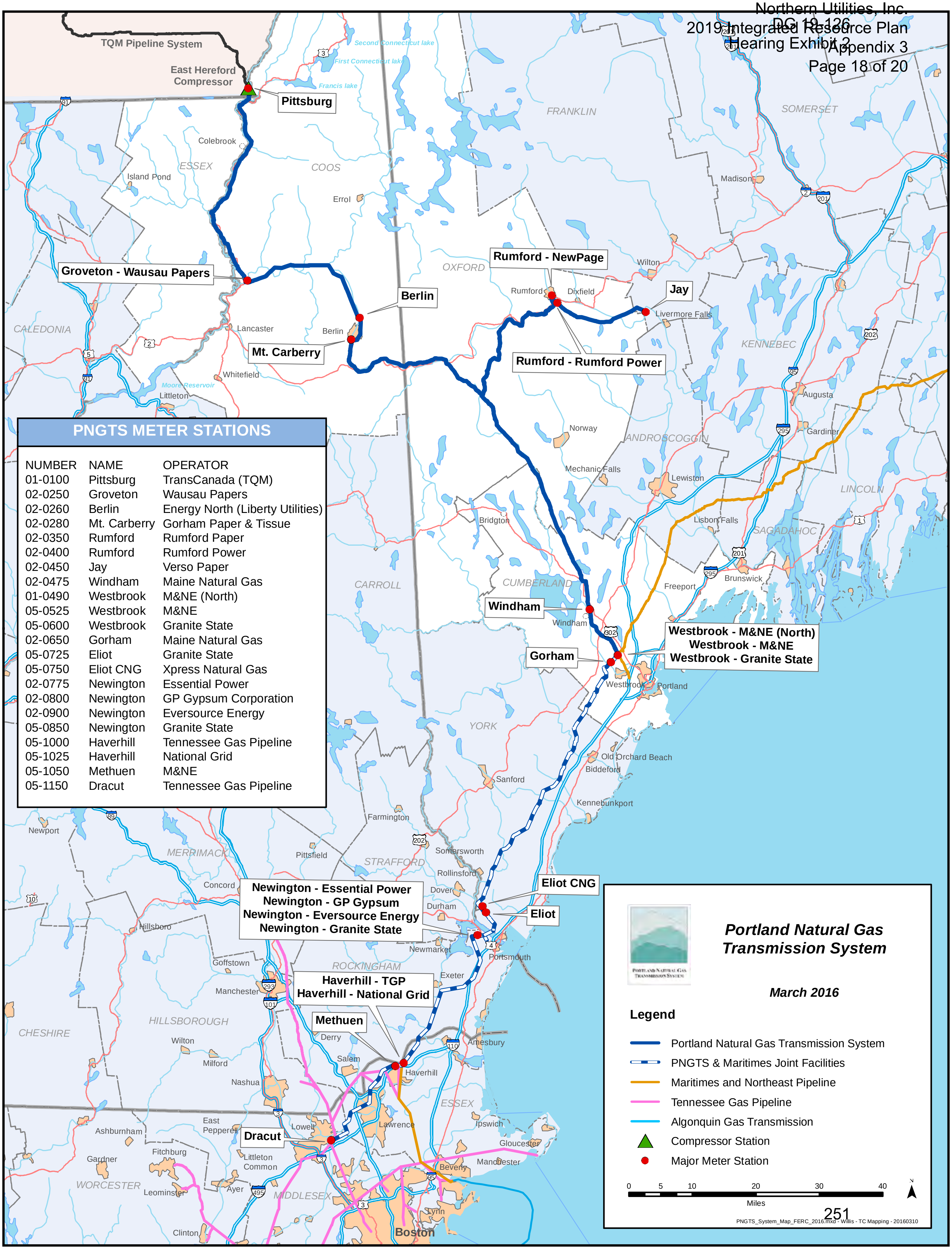

Union NDA
Energir NDA
Union EDA
Union SSMDA
STN 112 - MARTEN RIVER
STN 1206 - DEUX RIVIERES
QC
Energir EDA
LACHENAIE COMPRESSOR
St. Genevieve
Lachenaie
East Hereford
ME
STN 802 - CANDIAC
STN 148 - LES CEDRES
Philipsburg
Napierville
STN 116 - NORTH BAY
North Bay
Sudbury
STN 1211 - PEMBROKE
ON
Cornwall
Iroquois
Westbrook
STN 1217 - STITTSVILLE
Sault Ste. Marie
STN 119 - SUNDRIDGE
Enbridge EDA
STN 144 - BROCKVILLE
VT
NH
Crystal Falls
STN 123 - BRACEBRIDGE
Union NCDA
STN 142 - KINGSTON
Enbridge EDA
KPUC EDA
STN 139 - BELLEVILLE
Dracut
STN 127 - BARRIE
Enbridge CDA
STN 136 - COBOURG
Union EDA
NY
Lake Huron
Deward
Schomberg Gate
STN 130 - MAPLE
STN 134 - BOWMANVILLE
Victoria Square 2 CDA
Lake Ontario
Wright
MA
Goreway CDA
Union Parkway Belt
Enbridge Parkway CDA
Union ECDA
Niagara
Marshfield
Kirkwall
Chippawa
Farwell
Union CDA
RI
CT
STN 209 - ANCASTER
STN 211 - LINCOLN
Thorold CDA
Brookfield
St.Clair
Ramapo
MI
Union SWDA (Dawn)
Wisconsin
Dawn
Ellisburg
Lake St. Claire
Lake Erie
Leidy
Enbridge SWDA (Dawn)
NJ
PA
OH
IN
Joliet
Illinois
MD
WV
VA
Tennessee Gas Pipeline Co.
Millennium Pipeline
Empire Pipeline
Columbia Gas Transmission Corp.
Texas Eastern Transmission Corp.
National Fuel Gas
TRANSCO
Great Lakes Gas Transmission Co.
ANR
Vector
Panhandle
NGPL
NICOR
VIKING
PNGTS
M&NE
IGTS
Algonquin Gas Transmission LLC
Vermont Gas System
North Country Pipeline
Southern Union - Trunkline Gas
TransCanada
In business to deliver
Canadian Mainline Northeast Sales and Marketing
This map supersedes file Tarif_detail_northeast_V2.mxd (2018)
Map No: T0073_0000_01_00 - 20181906 - Rev:LP - TC Mapping

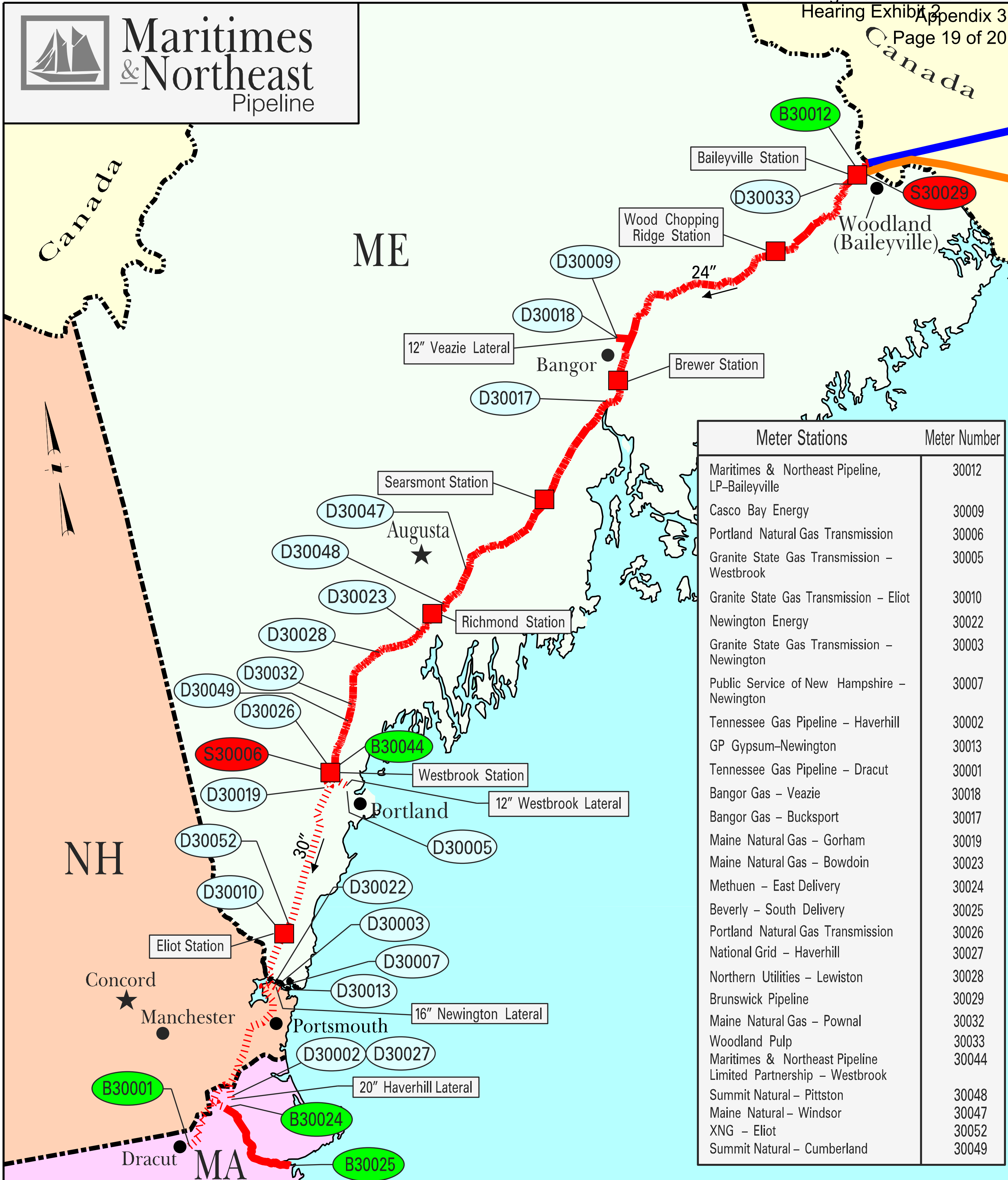
Gazoduc TQM


1 888 810-8800
Légende / legend
Réseau de Gazoduc TQM
TQM Pipeline system
Poste de mesurage de Gazoduc TQM
TQM Pipeline meter station
Point de livraison de Gazoduc TQM
TQM Pipeline delivery point
Point de réception de Gazoduc TQM
TQM Pipeline receipt point
Station de compression de Gazoduc TQM
TQM Pipeline compressor station
Réseau de TransCanada PipeLines
TransCanada PipeLines system
Réseau de Gaz Métro
Gaz Métro system
Ville/City
Lac Saint-Jean
Roberval
Alma
Jonquière
Chicoutimi
Chambord
Desbiens
La Baie
Québec
Saint-Augustin-de-Desmaures
La Tuque
Lévis
Saint-Romuald
Saint-Nicolas/Saint-Flavien
Pénitencier de Donnacona
Donnacona
Saint-Lambert-de-Lauzon
Portneuf
Saint-Flavien
Deschambault
Sainte-Marie
Vallée-Jonction
Saint-Joseph-de-Beauce
Beauceville
Saint-Georges
Fleuve Saint-Laurent
St. Lawrence River /
Sainte-Anne-de-la-Pérade
Saint-Georges
Grand-Mère
Saint-Narcisse
Saint-Maurice
Champlain
N
Province de / of Québec
Trois-Rivières
Bécancour
Pointe-du-Lac
Louiseville
Yamachiche
Sainte-Geneviève-de-Berthier
Lac Saint-Pierre
Saint-Joachin-de-Courval
Mont-Tremblant
Saint-Agathe-des-Monts
Joliette
Berthierville
Drummondville
Sainte-Adèle
Lavaltrie
Lanoraie
Terrebonne2
Terrebonne
Saint-Jérôme
Mascouche
Mirabel(Saint-Janvier)
Lachenaie
L'Assomption
Saint-Hyacinthe
Acton-Vale
Oka
Mirabel
Repentigny
Asbestos
Boisbriand
Windsor
Laval
MAINE
Waterloo
Granby
Marbleton
Montréal
Montréal-Est
Waterloo
East Angus
Saint-Lazare
Sherbrooke
Farnham
Coaticook
Brossard
Bromont
Magog
Saint-Mathieu
Cowansville
Sainte-Anne-de-Sabrevois
East Hereford
NEW YORK
VERMONT
NEW HAMPSHIRE



PNGTS METER STATIONS

NUMBER	NAME	OPERATOR
01-0100	Pittsburg	TransCanada (TQM)
02-0250	Groveton	Wausau Papers
02-0260	Berlin	Energy North (Liberty Utilities)
02-0280	Mt. Carberry	Gorham Paper & Tissue
02-0350	Rumford	Rumford Paper
02-0400	Rumford	Rumford Power
02-0450	Jay	Verso Paper
02-0475	Windham	Maine Natural Gas
01-0490	Westbrook	M&NE (North)
05-0525	Westbrook	M&NE
05-0600	Westbrook	Granite State
02-0650	Gorham	Maine Natural Gas
05-0725	Eliot	Granite State
05-0750	Eliot CNG	Xpress Natural Gas
02-0775	Newington	Essential Power
02-0800	Newington	GP Gypsum Corporation
02-0900	Newington	Eversource Energy
05-0850	Newington	Granite State
05-1000	Haverhill	Tennessee Gas Pipeline
05-1025	Haverhill	National Grid
05-1050	Methuen	M&NE
05-1150	Dracut	Tennessee Gas Pipeline

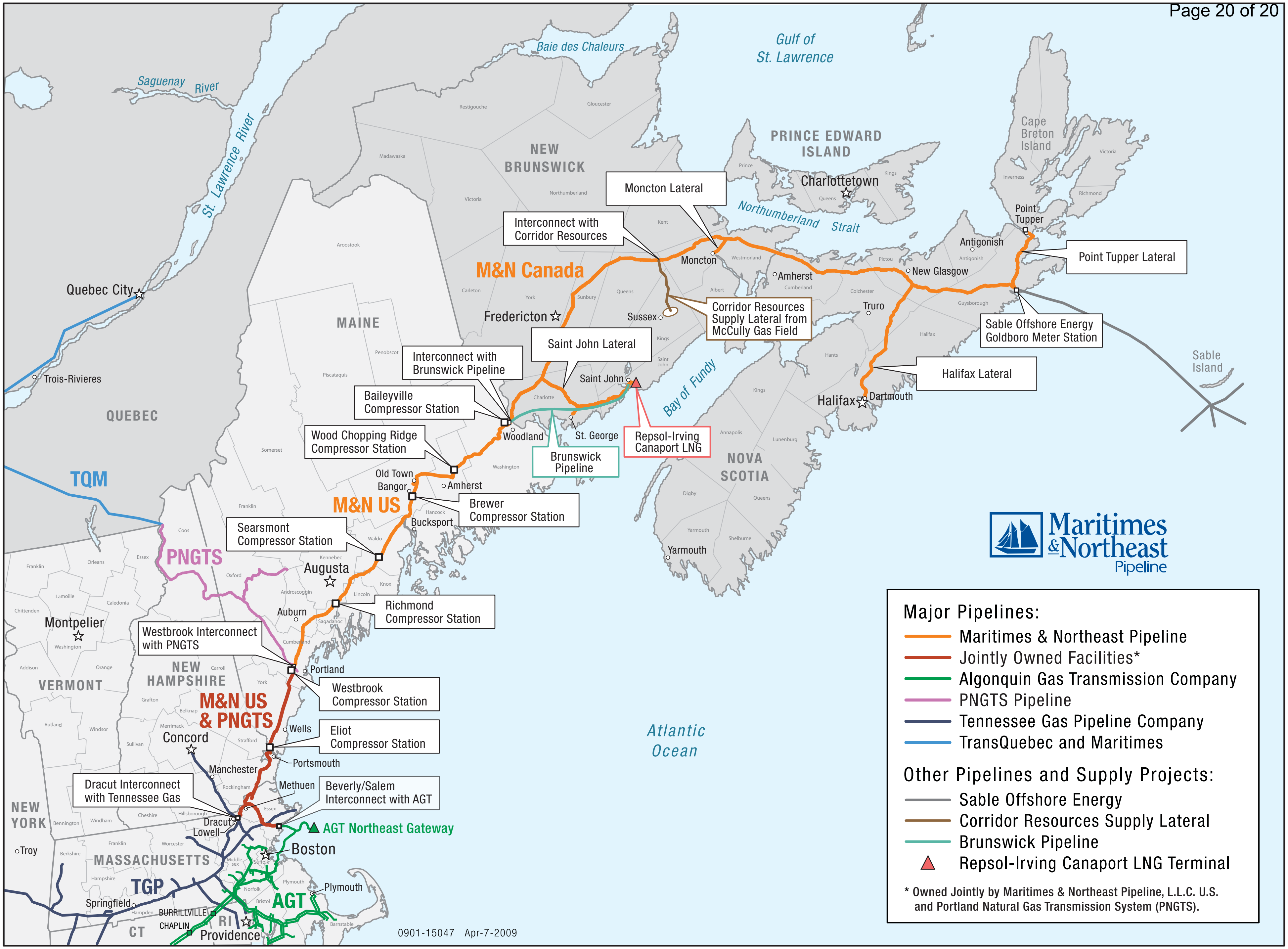


Meter Stations	Meter Number
Maritimes & Northeast Pipeline, LP–Baileyville	30012
Casco Bay Energy	30009
Portland Natural Gas Transmission	30006
Granite State Gas Transmission – Westbrook	30005
Granite State Gas Transmission – Eliot	30010
Newington Energy	30022
Granite State Gas Transmission – Newington	30003
Public Service of New Hampshire – Newington	30007
Tennessee Gas Pipeline – Haverhill	30002
GP Gypsum–Newington	30013
Tennessee Gas Pipeline – Dracut	30001
Bangor Gas – Veazie	30018
Bangor Gas – Bucksport	30017
Maine Natural Gas – Gorham	30019
Maine Natural Gas – Bowdoin	30023
Methuen – East Delivery	30024
Beverly – South Delivery	30025
Portland Natural Gas Transmission	30026
National Grid – Haverhill	30027
Northern Utilities – Lewiston	30028
Brunswick Pipeline	30029
Maine Natural Gas – Pownal	30032
Woodland Pulp	30033
Maritimes & Northeast Pipeline Limited Partnership – Westbrook	30044
Summit Natural – Pittston	30048
Maine Natural – Windsor	30047
XNG – Eliot	30052
Summit Natural – Cumberland	30049

Maritimes & Northeast Pipeline, LLC
M&N / PNGTS Joint Facilities
Maritimes & Northeast Pipeline, LP
Brunswick Pipeline

S Supply Meter Station
D Delivery Meter Station
B Bidirectional Check Meter Station
Centrifugal Compressor Station

0 25 50
GRAPHIC SCALE–MILES


Baie des Chaleurs
Gulf of St. Lawrence
Saguenay River
St. Lawrence River
NEW BRUNSWICK
PRINCE EDWARD ISLAND
Charlottetown
Northumberland Strait
Cape Breton Island
Moncton Lateral
Interconnect with Corridor Resources
Point Tupper
Antigonish
Point Tupper Lateral
M&N Canada
Moncton
Amherst
New Glasgow
Quebec City
Fredericton
Sussex
Corridor Resources Supply Lateral from McCully Gas Field
Truro
Sable Offshore Energy Goldboro Meter Station
MAINE
Saint John Lateral
Sable Island
Interconnect with Brunswick Pipeline
Saint John
Bay of Fundy
Halifax Lateral
Trois-Rivieres
Baileyville Compressor Station
Halifax
Dartmouth
QUEBEC
Woodland
St. George
Repsol-Irving Canaport LNG
Wood Chopping Ridge Compressor Station
Brunswick Pipeline
NOVA SCOTIA
TQM
Old Town
Bangor
Amherst
M&N US
Brewer Compressor Station
Bucksport
Searsmont Compressor Station
Yarmouth
PNGTS
Augusta
Maritimes & Northeast Pipeline
Auburn
Richmond Compressor Station
Montpelier
Westbrook Interconnect with PNGTS
Portland
NEW HAMPSHIRE
VERMONT
Westbrook Compressor Station
M&N US & PNGTS
Wells
Concord
Eliot Compressor Station
Atlantic Ocean
Portsmouth
Manchester
Methuen
Dracut Interconnect with Tennessee Gas
Beverly/Salem Interconnect with AGT
NEW YORK
Dracut
Lowell
AGT Northeast Gateway
Troy
Boston
MASSACHUSETTS
TGP
Plymouth
Springfield
AGT
BURRILLVILLE
CHAPLIN
CT
RI
Providence
0901-15047 Apr-7-2009
Major Pipelines:
Maritimes & Northeast Pipeline
Jointly Owned Facilities*
Algonquin Gas Transmission Company
PNGTS Pipeline
Tennessee Gas Pipeline Company
TransQuebec and Maritimes
Other Pipelines and Supply Projects:
Sable Offshore Energy
Corridor Resources Supply Lateral
Brunswick Pipeline
Repsol-Irving Canaport LNG Terminal
* Owned Jointly by Maritimes & Northeast Pipeline, L.L.C. U.S. and Portland Natural Gas Transmission System (PNGTS).

OUTLINE OF APPENDIX 4

Energy Efficiency Program Details

Appendix_B_Budget_and _Performance
Metrics_10_18_2018.xls
Truncated for Natural Gas

Efficiency Maine Trust Triennial Plan
Summary of Program Funding
FY 2020 Forecast

		Funding Sources	Statutory Requirements and Performance Metrics						Northern Utilities Calculations			
Line	Programs	Natural Gas Efficiency Procurement	Natural Gas (MMBtu)	Annualized Natural Gas Savings (Million cf)	Benefit / Cost Ratio	Job-Years Created[4]	Lifetime Benefit	Participant Cost	Total Cost	Average Measure Life (Yrs)	Lifetime MMBTU Savings	Cost per MMBtu
	(1)	(3)	(12)	(18)	(21)	(24)	(25)	(26)	(A) = (3)+(26)	(B) App. L	(C) = (12)*(B)	(D) =(A)/(D)
1b	Custom Natural Gas Measures	116,000	3,134	3.06	2.53	1.1	545,000	99,000	215,000			
2b	Prescriptive Natural Gas Measures	570,000	19,244	18.77	1.65	5.3	1,370,000	258,000	828,000			
3b	Small Business Natural Gas Measures	-	-	-	-	-	-	-	-			
4b	Distributor Natural Gas Measures	122,000	4,119	4.02	1.66	1.1	293,000	55,000	177,000			
5b	Retail Initiatives Natural Gas Measures	9,000	166	0.16	0.82	0.1	9,000	2,000	11,000			
6b	HESP Natural Gas Measures	131,000	4,042	3.94	1.74	1.2	772,000	312,000	443,000			
7b	Low Income Natural Gas Measures	95,000	2,931	2.86	1.74	0.9	560,000	226,000	321,000			
10	Programs Subtotal	$1,043,000	33,635	32.81	1.78	9.70	3,549,000	$952,000	$1,995,000			
11	Innovation	$5,000										
12	Public Information	$5,000										
13	Administration	$73,000										
14	EM&V	$26,000										
15	Inter-Agency Transfers	$21,000										
16	All Programs Total	**$ 1,173,000**	**33,635**	**32.81**	**1.78**	**9.70**	**$ 3,549,000**	**$ 952,000**	**$ 2,125,000**			
	CHECK	$ (222)										
	Residential Gas Program Subtotal	$ 235,000	7,138	6.96		2.19	$ 1,341,000	$ 540,000				
	C&I Gas Program Subtotal	$ 808,000	26,496	25.85		7.51	$ 2,208,000	$ 412,000				
	check	1,043,000	33,635	32.81		9.70	3,549,000	952,000				
	Residential Gas Program Administration	$ 29,291										
	C&I Gas Program Administration	$ 100,709										
	check	1,173,000										
	Residential Gas Program Total	$ 264,291	7,138	6.96		2.19	$ 1,341,000	$ 540,000	$ 804,291	23.1	165,069	$ 4.87
	C&I Gas Program Total	$ 908,709	26,496	25.85		7.51	$ 2,208,000	$ 412,000	$ 1,320,709	18.2	482,958	$ 2.73
	check	$ 1,173,000	33,635	32.81		9.70	3,549,000	$ 952,000	**$ 2,125,000**			

Appendix_B_Budget_and _Performance
Metrics_10_18_2018.xls
Truncated for Natural Gas

Efficiency Maine Trust Triennial Plan
Summary of Program Funding
FY 2021 Forecast

		Funding Sources	Statutory Requirements and Performance Metrics						Northern Utilities Calculations			
Line	Programs	Natural Gas Efficiency Procurement	Natural Gas (MMBtu)	Annualized Natural Gas Savings (Million cf)	Benefit / Cost Ratio	Job-Years Created[4]	Lifetime Benefit	Participant Cost	Total Cost	Average Measure Life (Yrs)	Lifetime MMBTU Savings	Cost per MMBtu
	(1)	(3)	(12)	(18)	(21)	(24)	(25)	(26)	(A) = (3)+(26)	(B) App. L	(C) = (12)*(B)	(D) =(A)/(D)
1b	Custom Natural Gas Measures	116,000	3,134	3.06	2.53	1.1	545,000	99,000	215,000			
2b	Prescriptive Natural Gas Measures	570,000	19,244	18.77	1.65	5.3	1,370,000	258,000	828,000			
3b	Small Business Natural Gas Measures	-	-	-	-	-	-	-	-			
4b	Distributor Natural Gas Measures	122,000	4,119	4.02	1.66	1.1	293,000	55,000	177,000			
5b	Retail Initiatives Natural Gas Measures	9,000	166	0.16	0.82	0.1	9,000	2,000	11,000			
6b	HESP Natural Gas Measures	129,000	3,980	3.88	1.74	1.2	760,000	307,000	436,000			
7b	Low Income Natural Gas Measures	95,000	2,931	2.86	1.74	0.9	560,000	226,000	321,000			
10	Programs Subtotal	$1,041,000	33,573	32.75	1.78	9.68	3,537,000	$947,000	$1,988,000			
11	Innovation	$5,000										
12	Public Information	$5,000										
13	Administration	$73,000										
14	EM&V	$26,000										
15	Inter-Agency Transfers	$21,000										
16	**All Programs Total**	**$ 1,171,000**	**33,573**	**32.75**	**1.78**	**9.68**	**$ 3,537,000**	**$ 947,000**	**$ 2,118,000**			
		$ 731										
	Residential Gas Program Subtotal	$ 233,000	7,076	6.90		2.17	$ 1,329,000	$ 535,000				
	C&I Gas Program Subtotal	$ 808,000	26,496	25.85		7.51	$ 2,208,000	$ 412,000				
	check	1,041,000	33,573	32.75		9.68	3,537,000	947,000				
	Residential Gas Program Administration	$ 29,097										
	C&I Gas Program Administration	$ 100,903										
	check	1,171,000										
	Residential Gas Program Total	$ 262,097	7,076	6.90		2.17	$ 1,329,000	$ 535,000	$ 797,097	23.1	163,642	$ 4.87
	C&I Gas Program Total	$ 908,903	26,496	25.85		7.51	$ 2,208,000	$ 412,000	$ 1,320,903	18.2	482,958	$ 2.74
	check	$ 1,171,000	33,573	32.75		9.68	3,537,000	$ 947,000	**$ 2,118,000**			

Appendix_B_Budget_and _Performance
Metrics_10_18_2018.xls
Truncated for Natural Gas

Efficiency Maine Trust Triennial Plan
Summary of Program Funding
FY 2022 Forecast

		Funding Sources	Statutory Requirements and Performance Metrics						Northern Utilities Calculations			
Line	Programs	Natural Gas Efficiency Procurement	Natural Gas (MMBtu)	Annualized Natural Gas Savings (Million cf)	Benefit / Cost Ratio	Job-Years Created[4]	Lifetime Benefit	Participant Cost	Total Cost	Average Measure Life (Yrs)	Lifetime MMBTU Savings	Cost per MMBtu
	(1)	(3)	(12)	(18)	(21)	(24)	(25)	(26)	(A) = (3)+(26)	(B) App. L	(C) = (12)*(B)	(D) =(A)/(D)
1b	Custom Natural Gas Measures	116,000	3,134	3.06	2.53	1.1	545,000	99,000	215,000			
2b	Prescriptive Natural Gas Measures	570,000	19,244	18.77	1.65	5.3	1,370,000	258,000	828,000			
3b	Small Business Natural Gas Measures	-	-	-	-	-	-	-	-			
4b	Distributor Natural Gas Measures	122,000	4,119	4.02	1.66	1.1	293,000	55,000	177,000			
5b	Retail Initiatives Natural Gas Measures	9,000	166	0.16	0.82	0.1	9,000	2,000	11,000			
6b	HESP Natural Gas Measures	126,000	3,887	3.79	1.74	1.2	742,000	300,000	426,000			
7b	Low Income Natural Gas Measures	94,000	2,900	2.83	1.74	0.9	554,000	224,000	318,000			
10	Programs Subtotal	$1,037,000	33,449	32.63	1.78	9.64	3,513,000	$938,000	$1,975,000			
11	Innovation	$5,000										
12	Public Information	$5,000										
13	Administration	$73,000										
14	EM&V	$26,000										
15	Inter-Agency Transfers	$21,000										
16	**All Programs Total**	**$ 1,167,000**	**33,449**	**32.63**	**1.78**	**9.64**	**$ 3,513,000**	**$ 938,000**	**$ 2,105,000**			
		$ (316)										
	Residential Gas Program Subtotal	$ 229,000	6,953	6.78		2.13	$ 1,305,000	$ 526,000				
	C&I Gas Program Subtotal	$ 808,000	26,496	25.85		7.51	$ 2,208,000	$ 412,000				
	check	1,037,000	33,449	32.63		9.64	3,513,000	938,000				
	Residential Gas Program Administration	$ 28,708										
	C&I Gas Program Administration	$ 101,292										
	check	1,167,000										
	Residential Gas Program Total	$ 257,708	6,953	6.78		2.13	$ 1,305,000	$ 526,000	$ 783,708	23.1	160,788	$ 4.87
	C&I Gas Program Total	$ 909,292	26,496	25.85		7.51	$ 2,208,000	$ 412,000	$ 1,321,292	18.2	482,958	$ 2.74
	check	$ 1,167,000	33,449	32.63		9.64	3,513,000	$ 938,000	**$ 2,105,000**			

Program Cost-Effectiveness - 2018 PLAN

	Total Resource Benefit / Cost Ratio	Benefit ($000)	Utility Costs ($000)	Customer Costs ($000)	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual MMBTU Savings	Lifetime MMBTU Savings
Residential Programs											
Home Energy Assistance	1.00	$ 340.5	$ 339.5	$ -	19.1	151.2	1.8	1.1	60	1,859.4	38,285.3
ENERGY STAR Homes	1.07	$ 269.3	$ 174.0	$ 77.1	7.2	51.9	1.3	0.5	39	1,312.5	32,046.0
Home Performance with Energy Star	1.02	$ 246.9	$ 183.0	$ 58.7	23.3	219.0	4.4	3.6	89	1,381.3	24,573.3
ENERGY STAR Products	1.14	$ 549.2	$ 293.6	$ 190.1	17.0	264.8	8.6	-	458	3,629.4	60,691.6
Home Energy Reports	0.77	$ 111.9	$ 145.1	$ -	-	-	-	-	10,000	4,980.0	13,010.0
Sub-Total Residential	**1.04**	**$ 1,517.8**	**$ 1,135.2**	**$ 325.9**	**66.6**	**686.9**	**16.1**	**5.2**	**10,646**	**13,162.5**	**168,606.2**
Commercial, Industrial & Municipal											
Large Business Energy Solutions	1.73	$ 1,566.6	$ 535.0	$ 372.9	-	-	-	-	60	14,000.2	203,586.7
Small Business Energy Solutions	1.50	$ 774.9	$ 310.3	$ 205.3	1.5	27.2	0.1	-	262	6,380.9	107,870.9
C&I Education		$ -	$ 16.7	$ -	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.63**	**$ 2,341.5**	**$ 862.0**	**$ 578.2**	**1.5**	**27.2**	**0.1**	**-**	**322**	**20,381.1**	**311,457.6**
Total	**1.33**	**$ 3,859.3**	**$ 1,997.2**	**$ 904.1**	**68.1**	**714.1**	**16.2**	**5.2**	**10,968**	**33,543.6**	**480,063.8**

Program Cost-Effectiveness - 2018 ACTUAL

	Total Resource Benefit / Cost Ratio	Benefit ($000)	Utility Costs ($000)	Customer Costs ($000)	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual MMBTU Savings	Lifetime MMBTU Savings
Residential Programs											
Home Energy Assistance	1.43	$ 502.2	$ 350.0	$ -	8.5	182.8	0.7	1.8	91	3,017.9	55,805.2
ENERGY STAR Homes	2.39	$ 767.0	$ 213.1	$ 107.2	121.0	2,394.625	51.7	21.4	129	2,497.2	61,900.0
Home Performance with Energy Star	1.37	$ 316.3	$ 142.6	$ 88.6	12.4	216.7	1.3	1.4	41	1,630.1	35,053.8
ENERGY STAR Products	1.01	$ 668.1	$ 344.8	$ 315.5	13.6	219.8	13.3	-	526	4,431.1	76,100.4
Home Energy Reports	0.00	$ -	$ 110.4	$ -	-	-	-	-	10,577	-	-
Sub-Total Residential	**1.35**	**$ 2,253.6**	**$ 1,160.9**	**$ 511.4**	**155.5**	**3,014.0**	**67.0**	**24.6**	**11,364**	**11,576.3**	**228,859.4**
Commercial, Industrial & Municipal											
Large Business Energy Solutions	2.20	$ 1,225.3	$ 358.9	$ 196.9	-	-	-	-	11	11,254.6	172,173.8
Small Business Energy Solutions	1.27	$ 839.8	$ 340.3	$ 321.6	(16.6)	(437.6)	(0.5)	-	50	6,958.3	124,943.4
C&I Education		$ -	$ 6.6	$ -	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.69**	**$ 2,065.1**	**$ 705.8**	**$ 518.6**	**(16.6)**	**(437.6)**	**(0.5)**	**-**	**61**	**18,212.9**	**297,117.2**
Total	**1.49**	**$ 4,318.7**	**$ 1,866.7**	**$ 1,030.0**	**138.9**	**2,576.4**	**66.5**	**24.6**	**11,425**	**29,789.2**	**525,976.6**

Program Cost-Effectiveness - 2019 PLAN

	Total Resource Benefit / Cost Ratio	Benefit ($000)	Utility Costs ($000)	Customer Costs ($000)	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual MMBTU Savings	Lifetime MMBTU Savings
Residential Programs											
Home Energy Assistance	0.99	$ 369.8	$ 374.0	$ -	16.9	143.4	1.7	1.0	62	1,964.6	40,000.9
ENERGY STAR Homes	1.11	$ 306.8	$ 191.4	$ 84.2	9.2	64.2	1.7	0.6	43	1,436.1	35,031.0
Home Performance with Energy Star	1.01	$ 266.9	$ 204.2	$ 61.0	19.4	202.4	3.2	2.6	100	1,473.7	25,814.4
ENERGY STAR Products	1.21	$ 630.1	$ 315.2	$ 205.7	19.9	312.6	10.0	-	502	4,000.8	66,448.6
Home Energy Reports	1.02	$ 95.6	$ 93.3	$ -	-	-	-	-	10,000	3,170.0	9,620.0
									-		
Sub-Total Residential	**1.09**	**$ 1,669.1**	**$ 1,178.2**	**$ 350.9**	**65.4**	**722.6**	**16.7**	**4.2**	**10,707**	**12,045.2**	**176,914.9**
Commercial, Industrial & Municipal											
Large Business Energy Solutions	1.83	$ 1,933.1	$ 623.0	$ 431.6	-	-	-	-	72	16,432.7	241,209.7
Small Business Energy Solutions	1.60	$ 989.9	$ 380.5	$ 239.7	1.5	27.2	0.1	-	317	8,229.1	130,383.7
C&I Education		$ -	$ 18.4	$ -	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.73**	**$ 2,923.0**	**$ 1,022.0**	**$ 671.4**	**1.5**	**27.2**	**0.1**	**-**	**389**	**24,661.8**	**371,593.3**
Total	**1.43**	**$ 4,592.2**	**$ 2,200.1**	**$ 1,022.3**	**66.9**	**749.8**	**16.8**	**4.2**	**11,096**	**36,707.1**	**548,508.2**

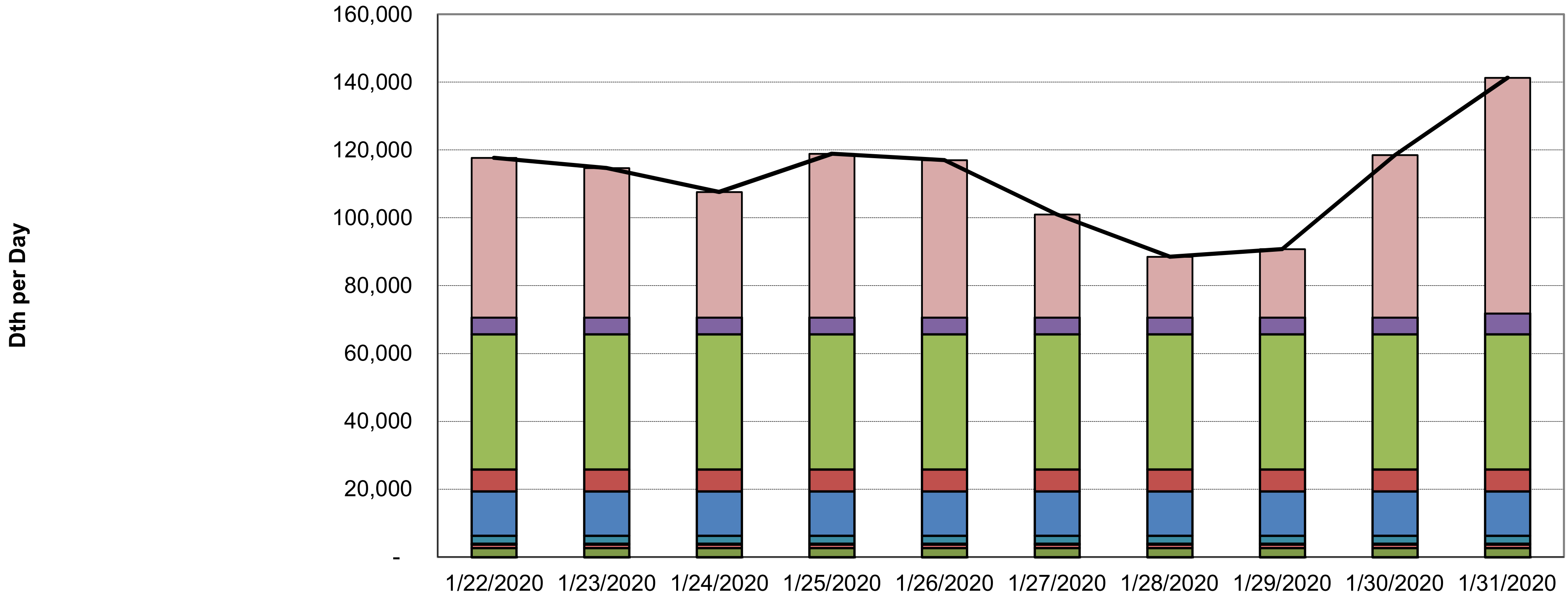
Program Cost-Effectiveness - 2020 PLAN

	Total Resource Benefit / Cost Ratio	Benefit ($000)	Utility Costs ($000)	Customer Costs ($000)	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	Annual MMBTU Savings	Lifetime MMBTU Savings
Residential Programs											
Home Energy Assistance	0.98	$ 400.8	$ 410.2	$ -	20.7	167.8	2.1	1.1	64	2,055.3	41,991.6
ENERGY STAR Homes	1.13	$ 326.5	$ 201.7	$ 86.9	9.6	67.6	1.8	0.7	44	1,486.0	36,212.0
Home Performance with Energy Star	1.02	$ 286.8	$ 218.4	$ 62.1	21.3	214.4	3.6	2.8	114	1,547.1	26,682.0
ENERGY STAR Products	1.26	$ 704.9	$ 337.0	$ 221.7	22.0	347.1	11.2	-	550	4,351.3	72,102.4
Home Energy Reports	0.82	$ 76.1	$ 93.3	$ -	-	-	-	-	10,000	2,110.0	7,320.0
Sub-Total Residential	**1.10**	**$ 1,795.1**	**$ 1,260.7**	**$ 370.8**	**73.6**	**796.9**	**18.7**	**4.6**	**10,772**	**11,549.7**	**184,308.0**
Commercial, Industrial & Municipal											
Large Business Energy Solutions	1.93	$ 2,361.8	$ 726.1	$ 500.5	-	-	-	-	85	19,311.0	285,853.4
Small Business Energy Solutions	1.83	$ 1,236.7	$ 407.5	$ 268.4	1.8	33.3	0.1	-	351	9,382.7	159,340.6
C&I Education	0.00	$ -	$ 18.6	$ -	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**1.87**	**$ 3,598.5**	**$ 1,152.1**	**$ 768.9**	**1.8**	**33.3**	**0.1**	**-**	**436**	**28,693.7**	**445,194.0**
Total	**1.52**	**$ 5,393.6**	**$ 2,412.8**	**$ 1,139.6**	**75.5**	**830.1**	**18.8**	**4.6**	**11,208**	**40,243.4**	**629,502.0**

OUTLINE OF APPENDIX 5

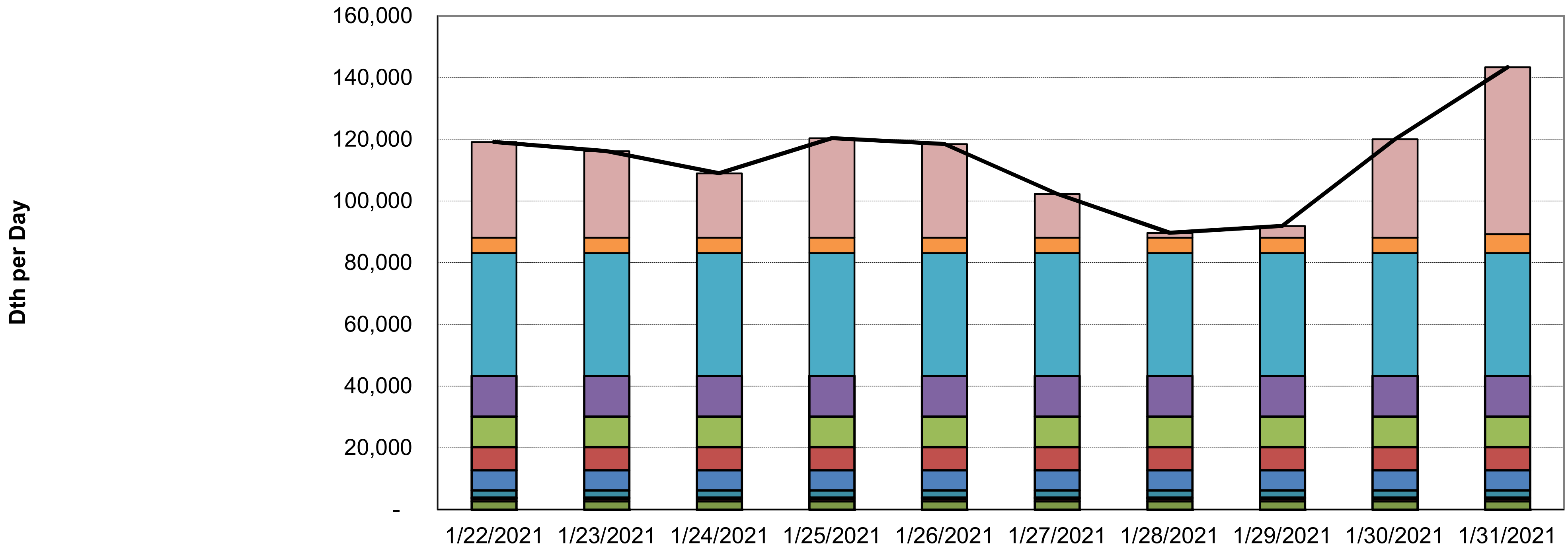
Supplemental Materials for the Preferred Portfolio Section

2019-2020 Design Winter Cold Snap



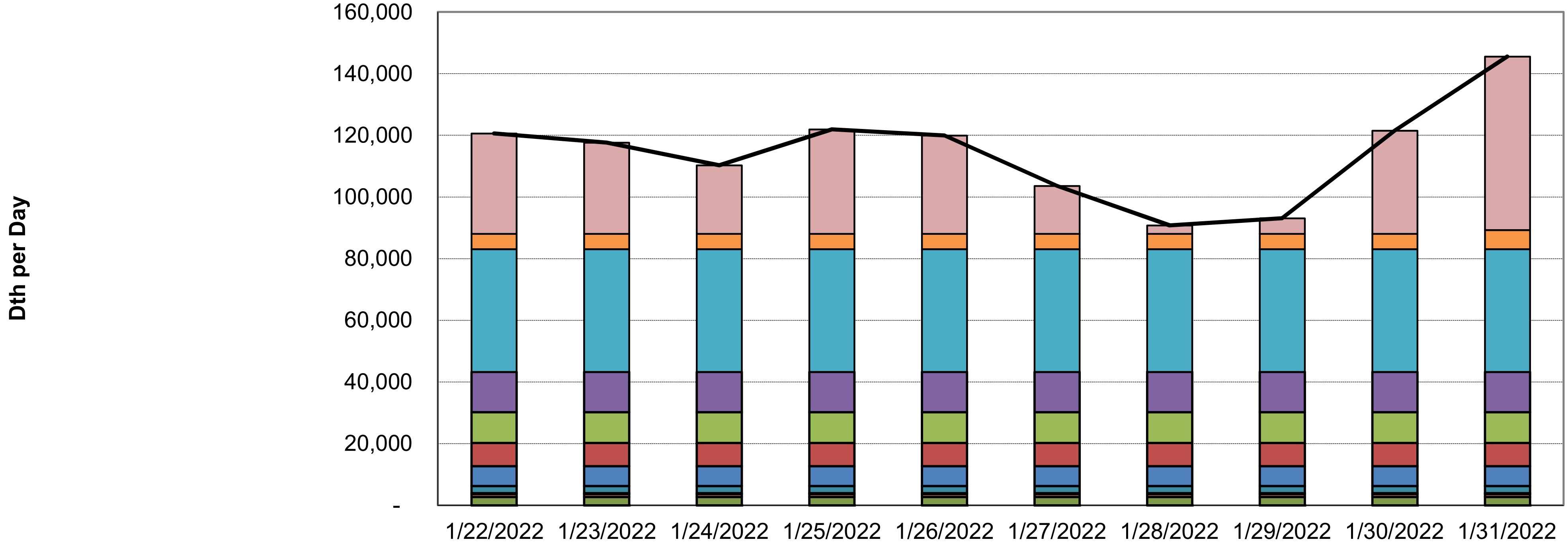
	1/22/2020	1/23/2020	1/24/2020	1/25/2020	1/26/2020	1/27/2020	1/28/2020	1/29/2020	1/30/2020	1/31/2020
Incremental Supply	47,048	44,081	36,987	48,292	46,375	30,399	17,941	20,186	47,913	69,477
LNG	4,948	4,939	4,940	4,939	4,940	4,939	4,941	4,942	4,939	6,141
Union Dawn Storage	39,823	39,823	39,823	39,823	39,823	39,823	39,823	39,823	39,823	39,823
Iroquois Receipts	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462
Tennessee Zone 0 and Zone L Pools	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
Tennessee Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
Transco Zone 6, non-NY Supply	286	286	286	286	286	286	286	286	286	286
Leidy Hub Supply	965	965	965	965	965	965	965	965	965	965
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	59	59	59	59	59	59	59	59	59	59
Cold Snap Loads	117,671	114,695	107,601	118,906	116,989	101,013	88,556	90,803	118,527	141,292

2020-2021 Design Winter Cold Snap



	1/22/2021	1/23/2021	1/24/2021	1/25/2021	1/26/2021	1/27/2021	1/28/2021	1/29/2021	1/30/2021	1/31/2021
Incremental Supply	31,038	28,025	20,842	32,287	30,348	14,172	1,558	3,837	31,904	54,061
LNG	4,940	4,940	4,939	4,939	4,939	4,941	4,943	4,939	4,941	6,141
Union Dawn Storage	39,823	39,823	39,823	39,823	39,823	39,823	39,823	39,823	39,823	39,823
Tennessee Zone 0 and Zone L Pools	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
PXP Dawn Supply	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965
AB Ramapo Supply	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Iroquois Receipts	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462
Tennessee Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
Transco Zone 6, non-NY Supply	286	286	286	286	286	286	286	286	286	286
Leidy Hub Supply	965	965	965	965	965	965	965	965	965	965
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	59	59	59	59	59	59	59	59	59	59
Cold Snap Loads	119,117	116,104	108,921	120,366	118,427	102,252	89,640	91,916	119,984	143,341

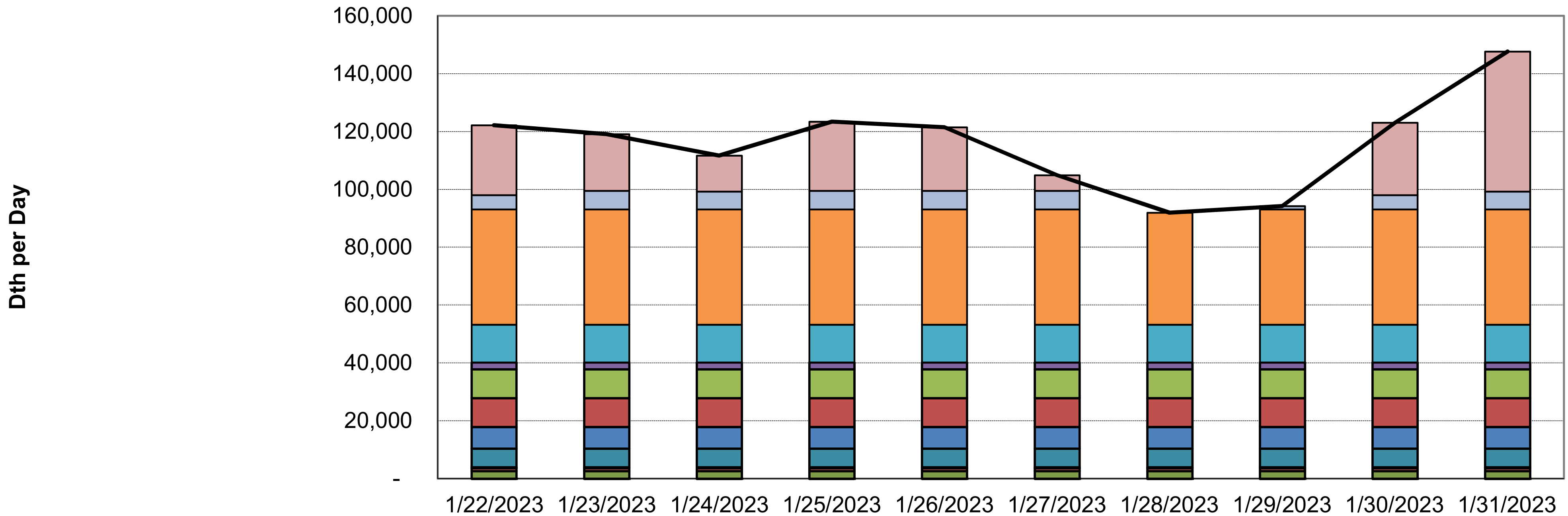
2021-2022 Design Winter Cold Snap



	1/22/2022	1/23/2022	1/24/2022	1/25/2022	1/26/2022	1/27/2022	1/28/2022	1/29/2022	1/30/2022	1/31/2022
Incremental Supply	32,580	29,529	22,255	33,847	31,882	15,497	2,719	5,026	33,456	56,246
LNG	4,939	4,940	4,939	4,940	4,940	4,940	4,942	4,940	4,941	6,141
Union Dawn Storage	39,823	39,823	39,823	39,823	39,823	39,823	39,823	39,823	39,823	39,823
Tennessee Zone 0 and Zone L Pools	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
PXP Dawn Supply	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965
AB Ramapo Supply	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Iroquois Receipts	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462
Tennessee Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
Transco Zone 6, non-NY Supply	286	286	286	286	286	286	286	286	286	286
Leidy Hub Supply	965	965	965	965	965	965	965	965	965	965
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	59	59	59	59	59	59	59	59	59	59
Cold Snap Loads	120,659	117,608	110,334	121,926	119,961	103,576	90,801	93,105	121,536	145,526

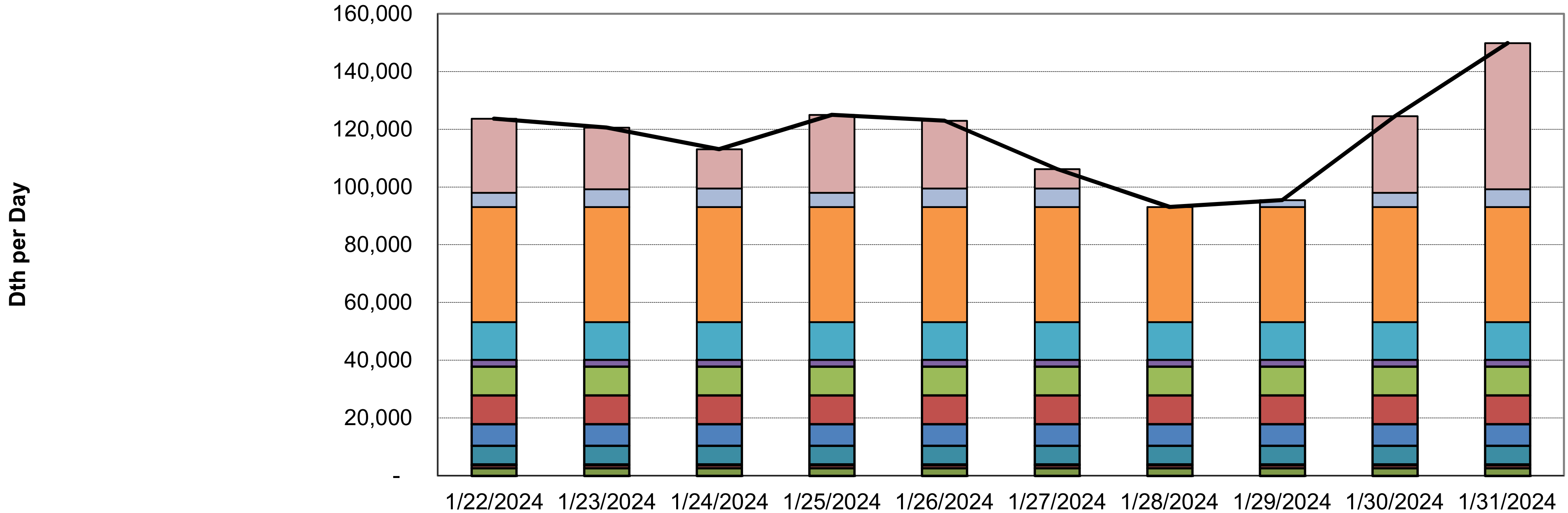
DG 19-126
Hearing Exhibit 2

2022-2023 Design Winter Cold Snap



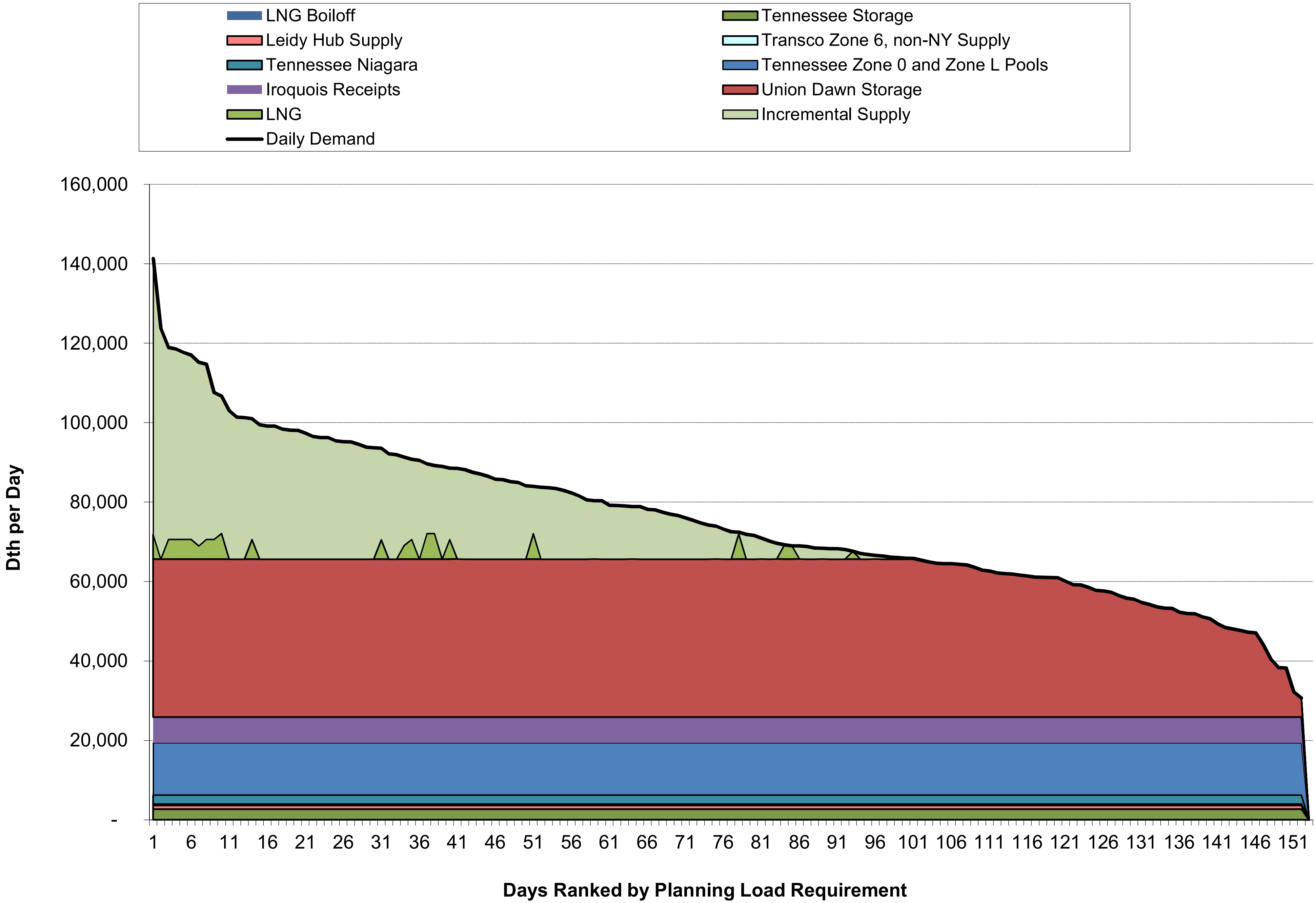
	1/22/2023	1/23/2023	1/24/2023	1/25/2023	1/26/2023	1/27/2023	1/28/2023	1/29/2023	1/30/2023	1/31/2023
Incremental Supply	24,104	19,515	12,451	23,886	21,898	5,309	-	-	24,992	48,419
LNG	4,940	6,441	6,141	6,441	6,441	6,441	-	1,148	4,941	6,141
Union Dawn Storage	39,823	39,823	39,823	39,823	39,823	39,823	38,640	39,823	39,823	39,823
Tennessee Zone 0 and Zone L Pools	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
Tennessee Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
WXP Dawn Supply	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965
PXP Dawn Supply	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965
AB Ramapo Supply	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Iroquois Receipts	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462
Transco Zone 6, non-NY Supply	286	286	286	286	286	286	286	286	286	286
Leidy Hub Supply	965	965	965	965	965	965	965	965	965	965
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	59	59	59	59	59	59	59	59	59	59
Cold Snap Loads	122,148	119,060	111,696	123,431	121,443	104,854	91,921	94,252	123,037	147,664

2023-2024 Design Winter Cold Snap

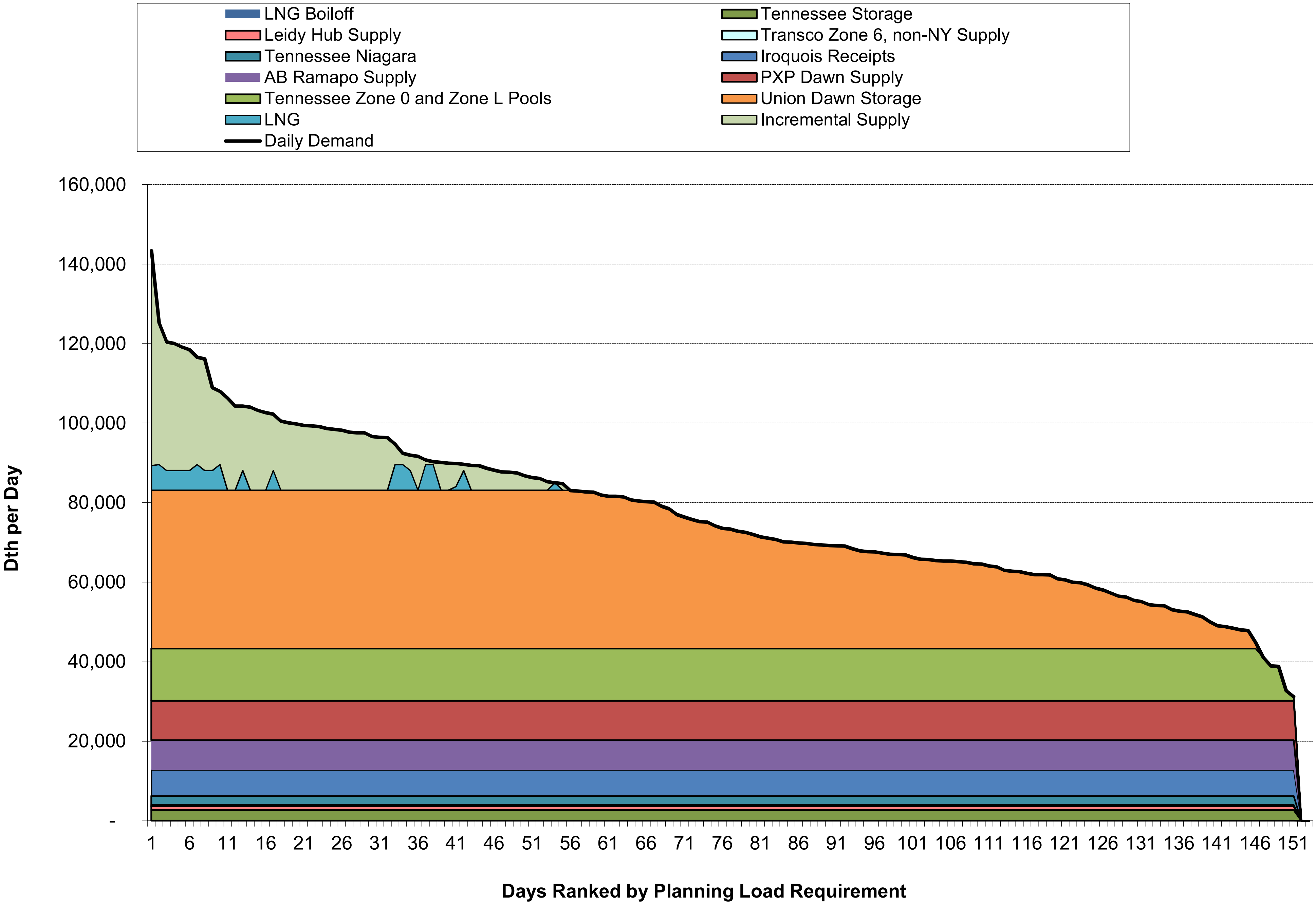


	1/22/2024	1/23/2024	1/24/2024	1/25/2024	1/26/2024	1/27/2024	1/28/2024	1/29/2024	1/30/2024	1/31/2024
Incremental Supply	25,642	21,312	13,557	26,941	23,427	6,629	-	-	26,540	50,603
LNG	4,939	6,144	6,441	4,939	6,441	6,441	-	2,332	4,941	6,141
Union Dawn Storage	39,823	39,823	39,823	39,823	39,823	39,823	39,796	39,823	39,823	39,823
Tennessee Zone 0 and Zone L Pools	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109	13,109
Tennessee Niagara	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327	2,327
WXP Dawn Supply	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965
PXP Dawn Supply	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965	9,965
AB Ramapo Supply	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Iroquois Receipts	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462	6,462
Transco Zone 6, non-NY Supply	286	286	286	286	286	286	286	286	286	286
Leidy Hub Supply	965	965	965	965	965	965	965	965	965	965
Tennessee Storage	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644
LNG Boiloff	59	59	59	59	59	59	59	59	59	59
Cold Snap Loads	123,686	120,560	113,102	124,985	122,972	106,174	93,077	95,436	124,585	149,848

2019-2020 Nov-Mar Design Winter Load Duration Curve

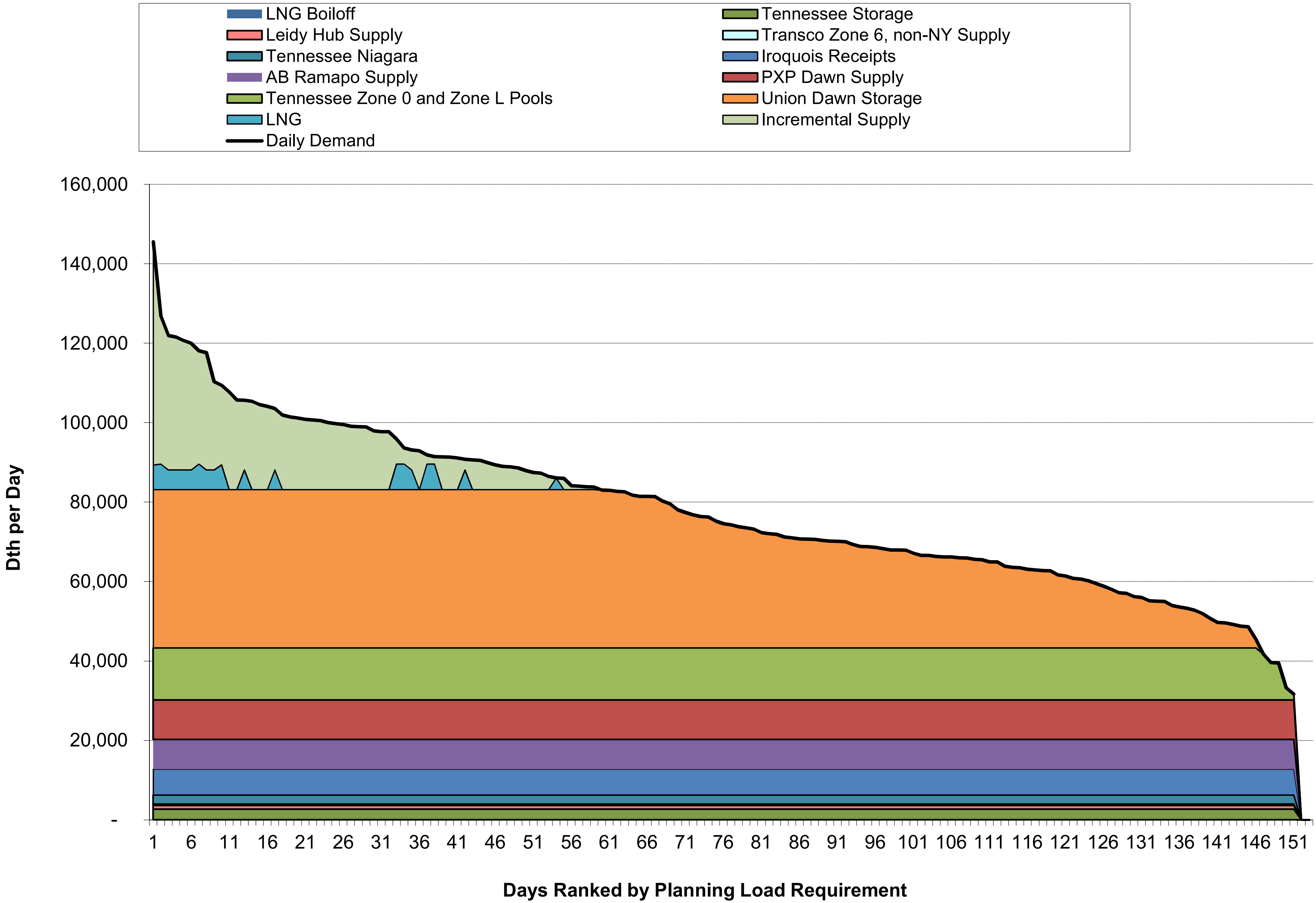


2020-2021 Nov-Mar Design Winter Load Duration Curve

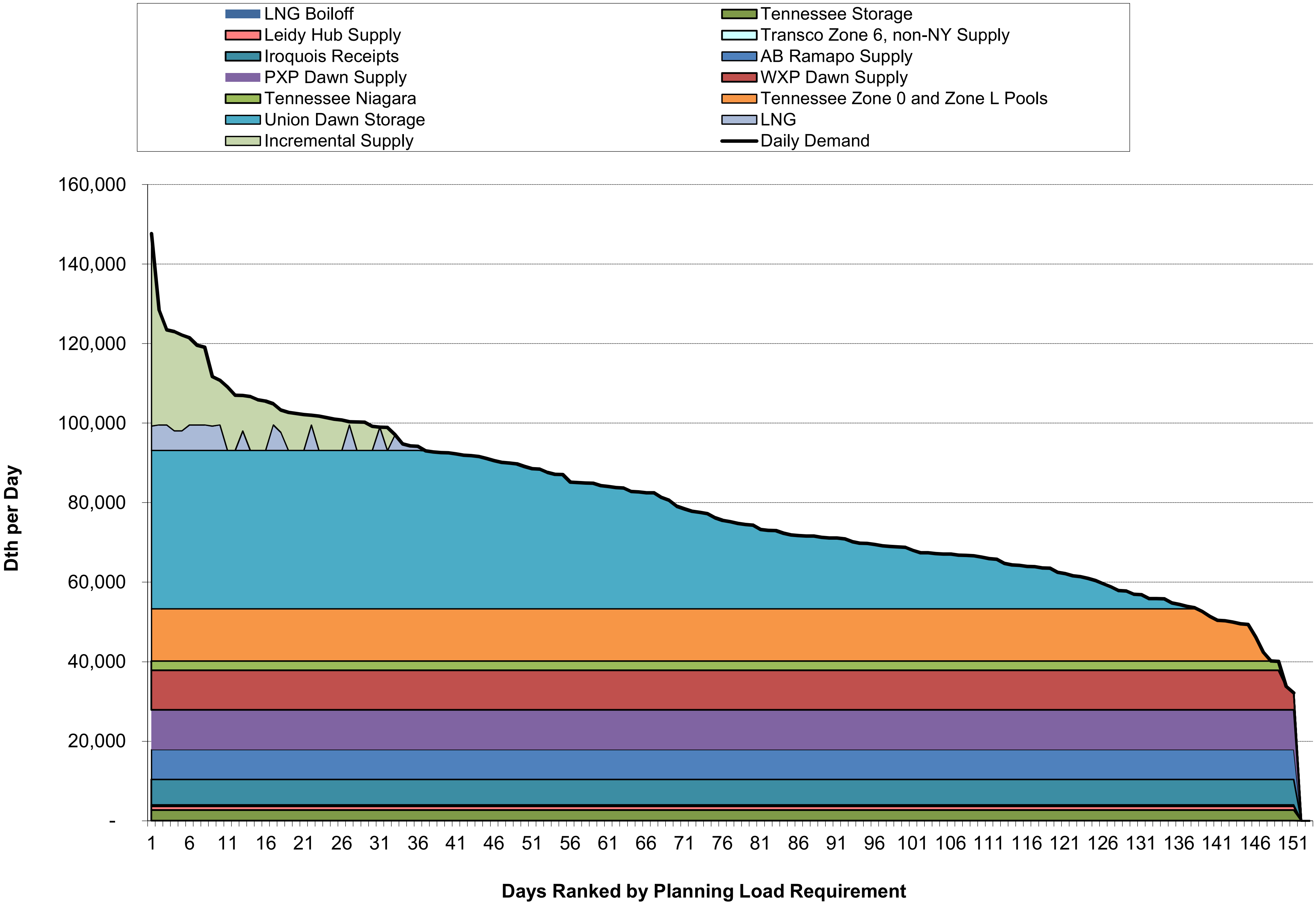


DG 19-126
Hearing Exhibit 2

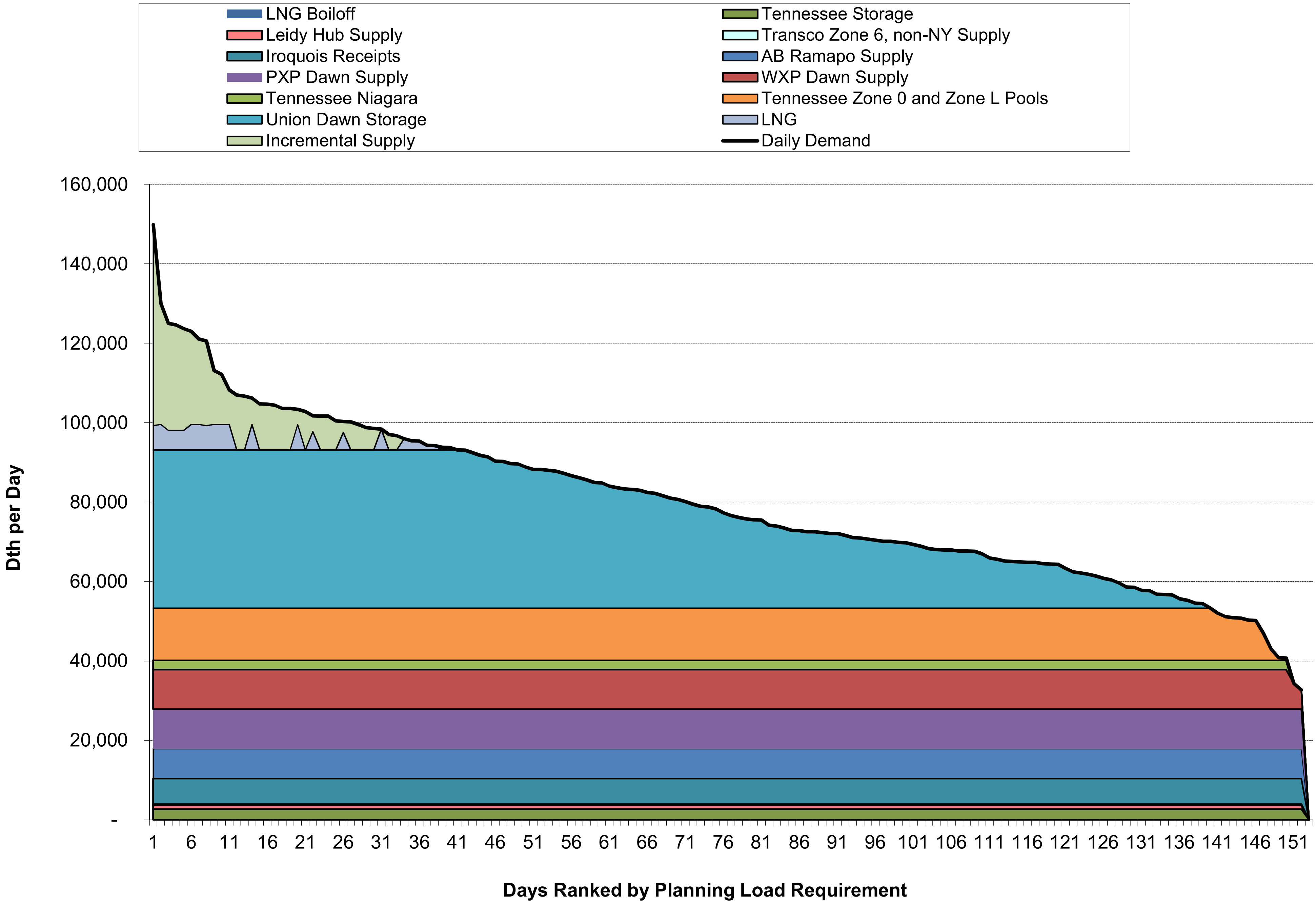
2021-2022 Nov-Mar Design Winter Load Duration Curve



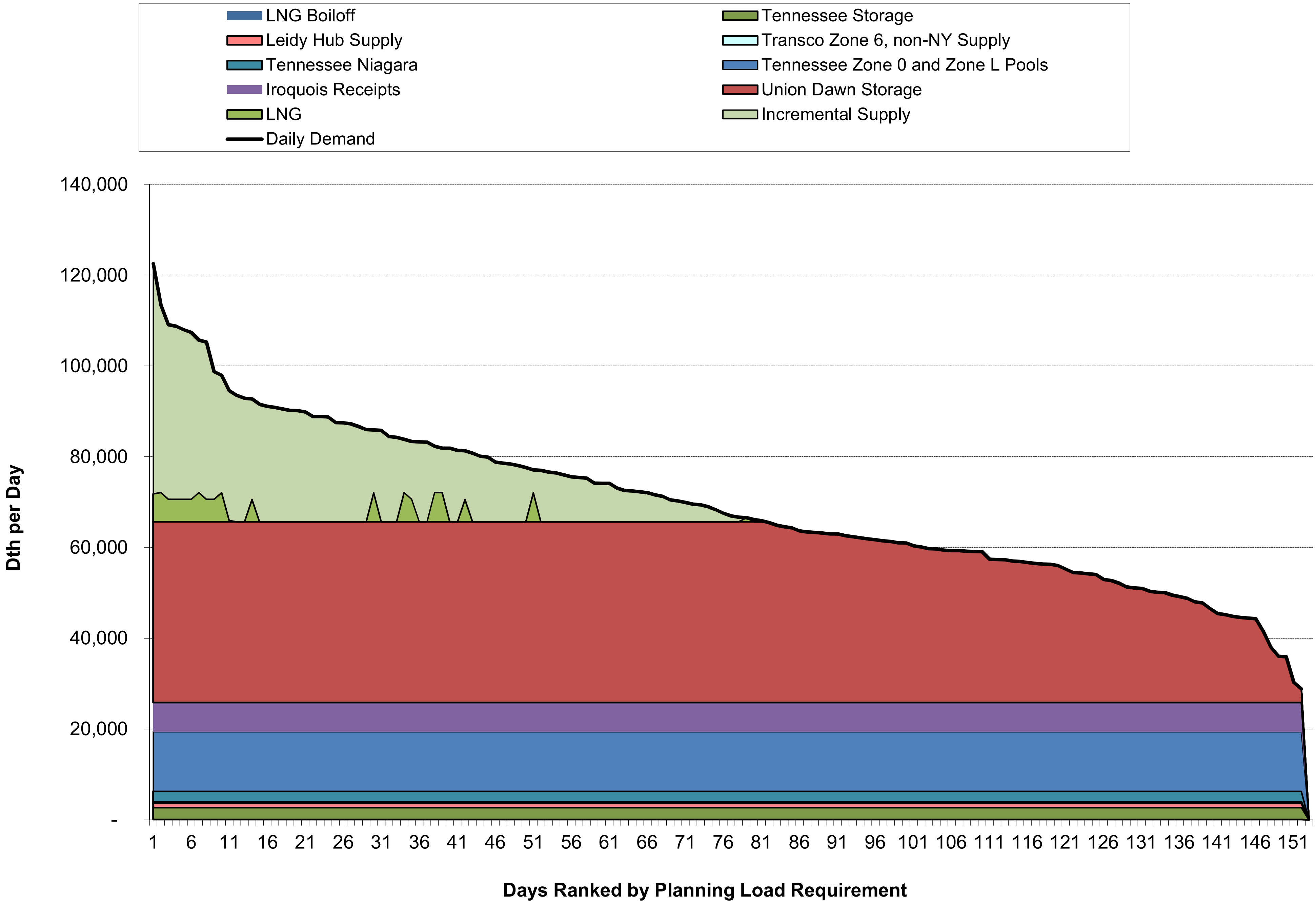
2022-2023 Nov-Mar Design Winter Load Duration Curve



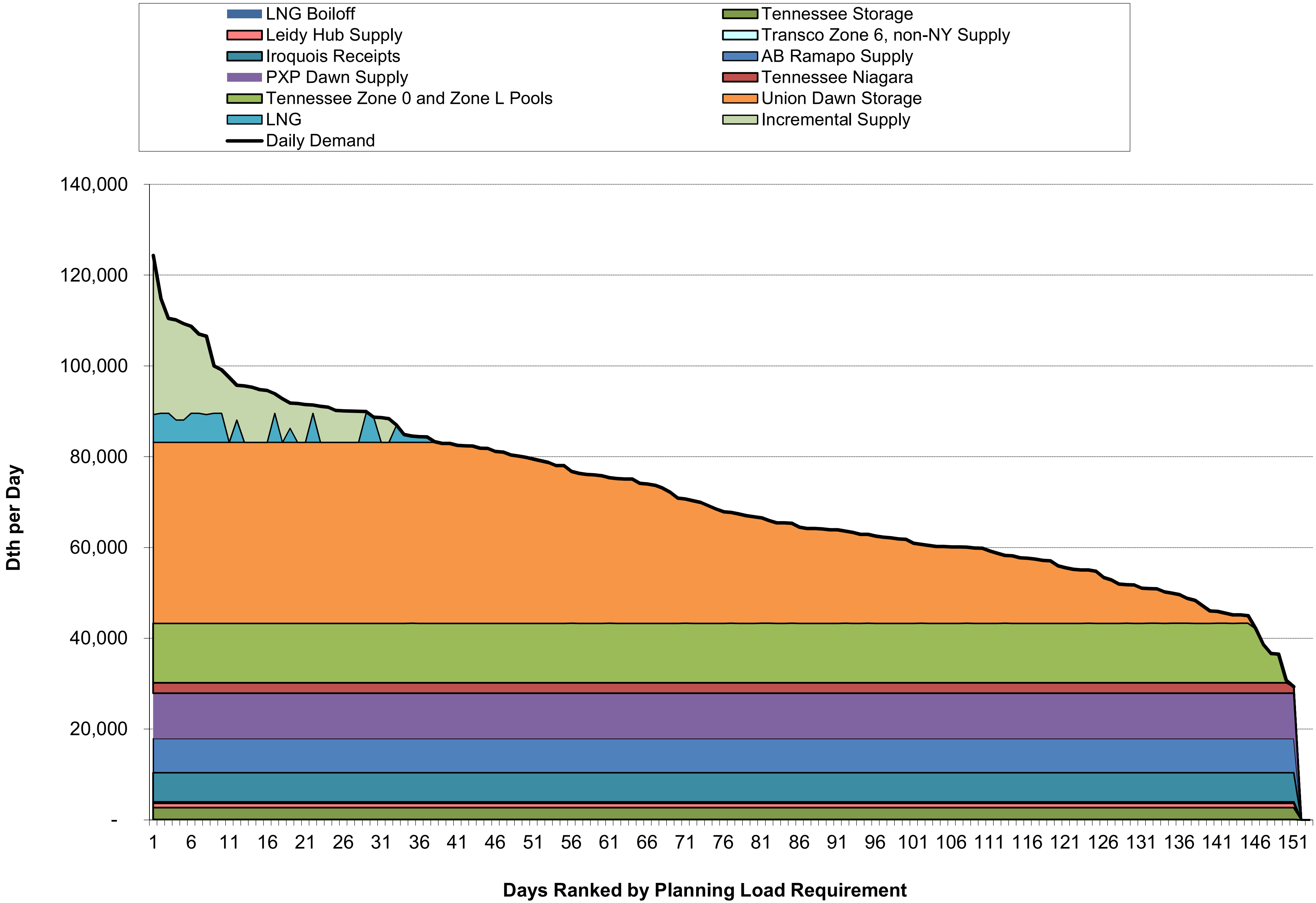
2023-2024 Nov-Mar Design Winter Load Duration Curve



2019-2020 Nov-Mar Normal Winter Load Duration Curve

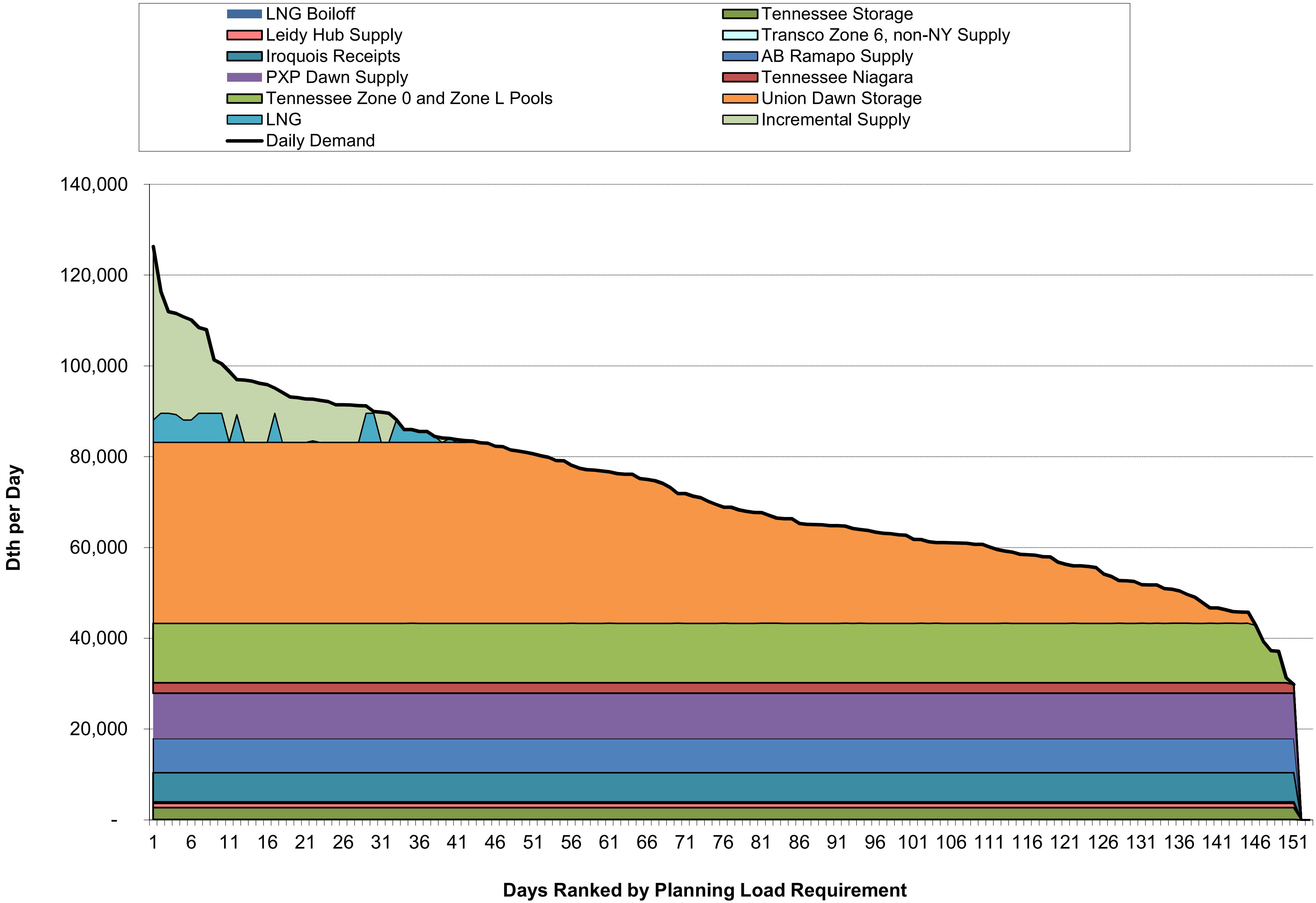


2020-2021 Nov-Mar Normal Winter Load Duration Curve

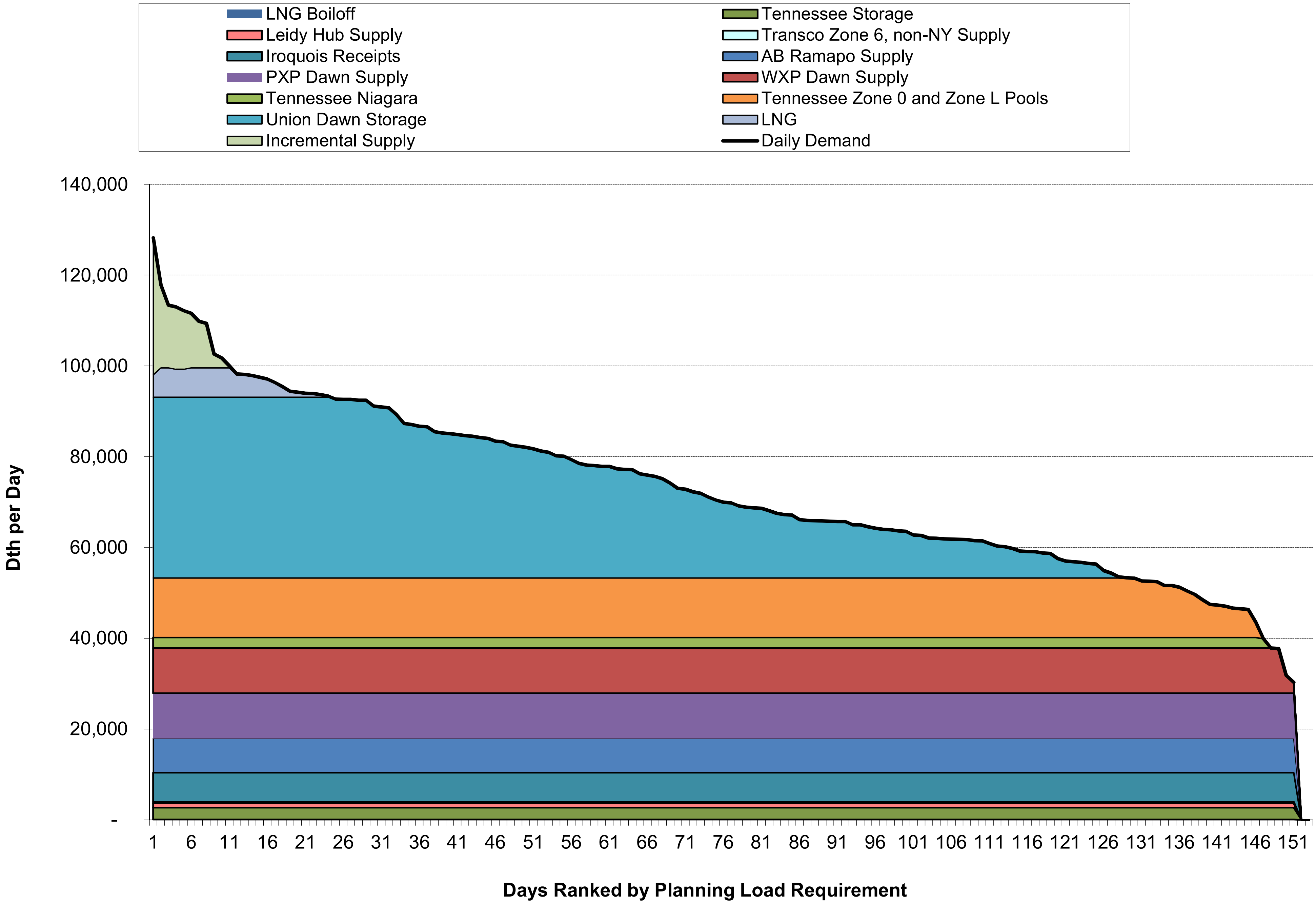


DG 19-126
Hearing Exhibit 2

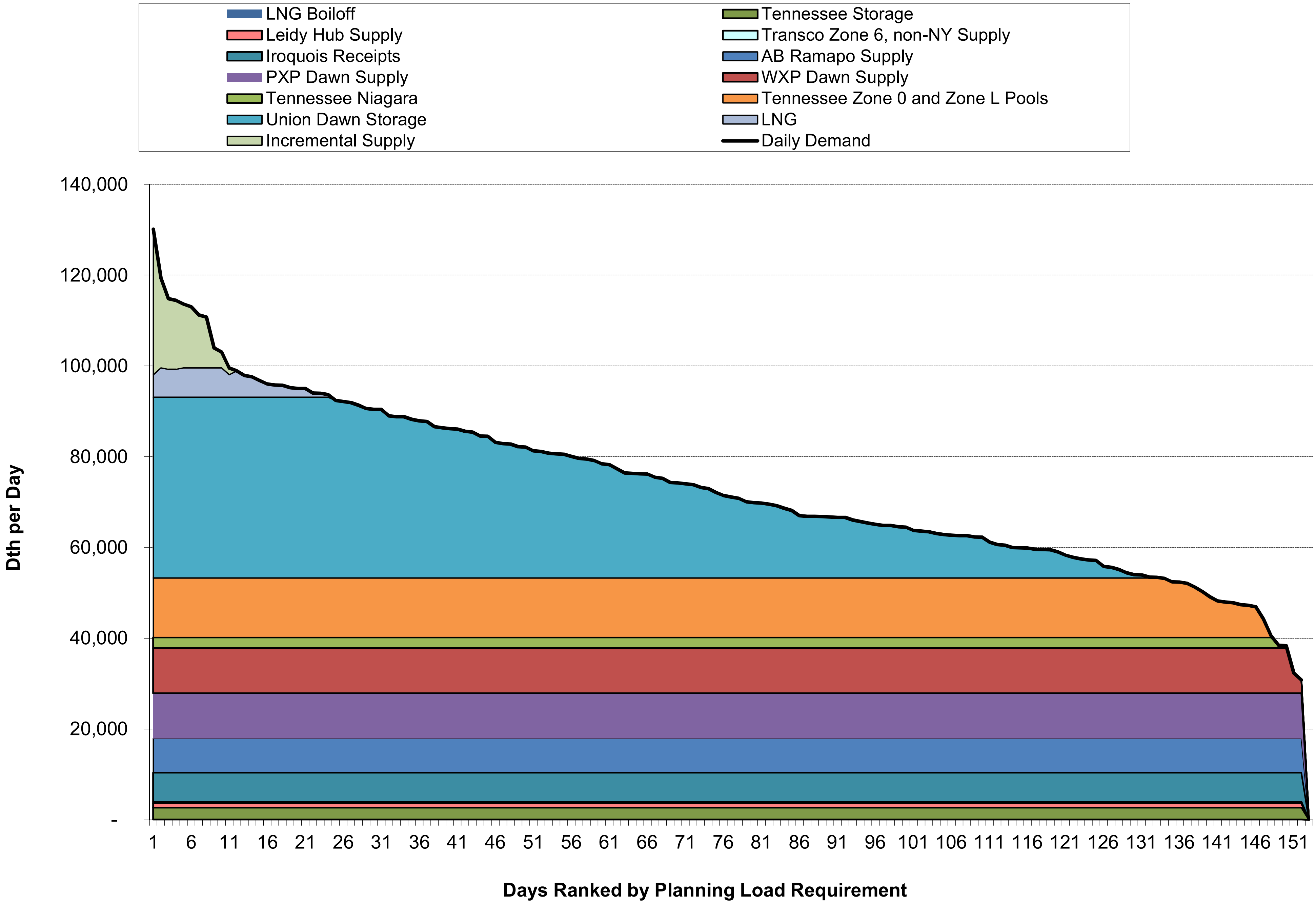
2021-2022 Nov-Mar Normal Winter Load Duration Curve



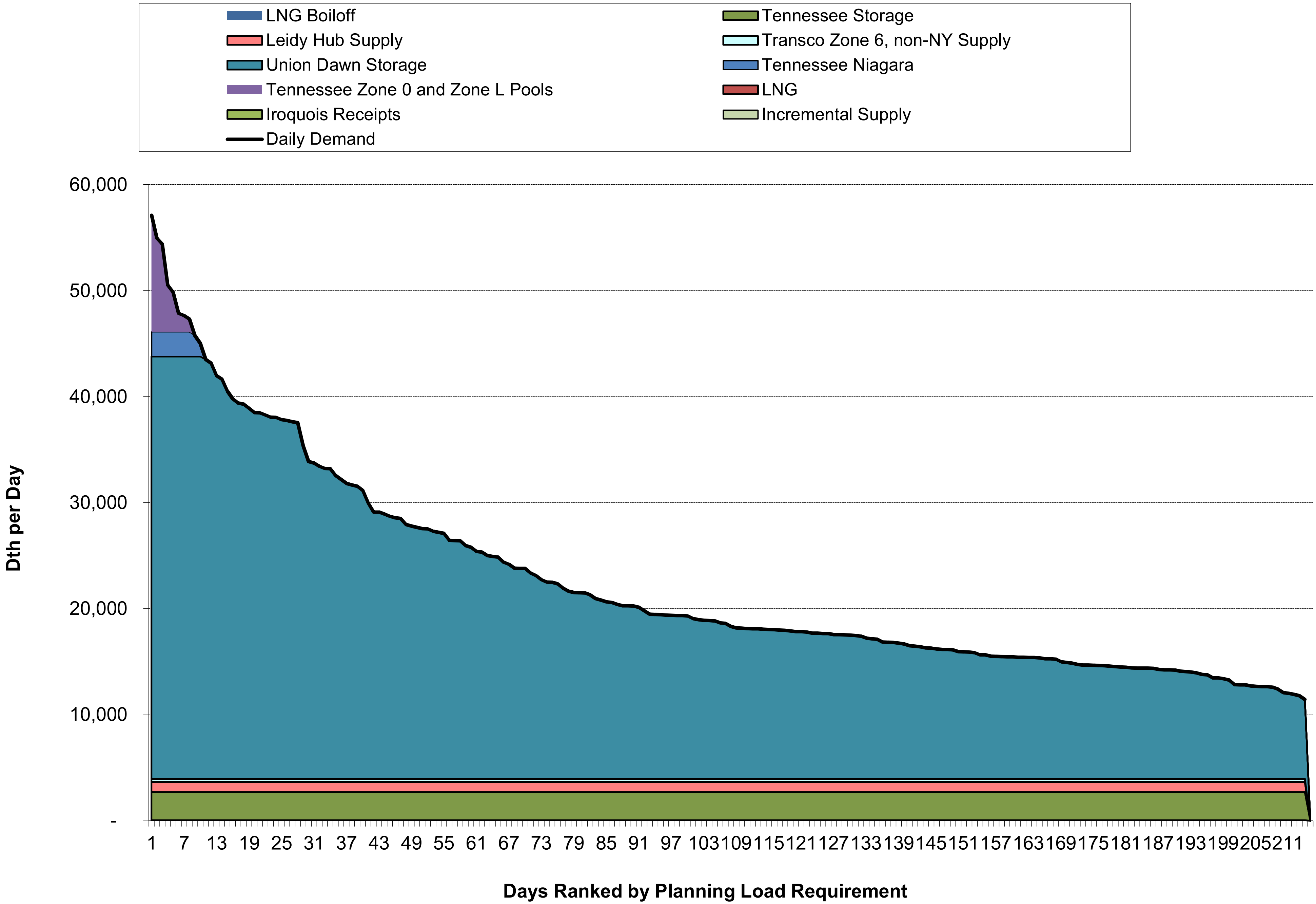
2022-2023 Nov-Mar Normal Winter Load Duration Curve



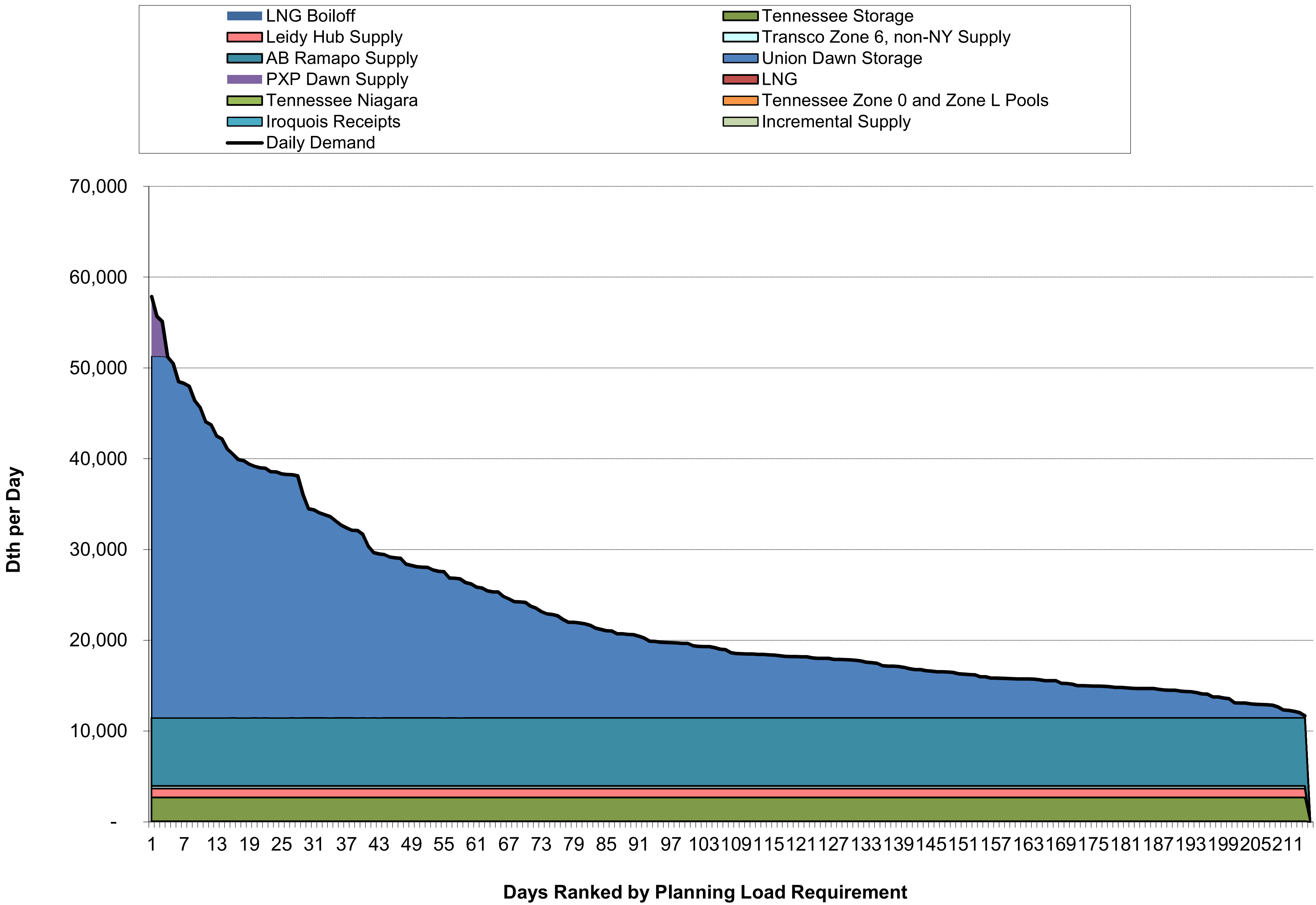
2023-2024 Nov-Mar Normal Winter Load Duration Curve



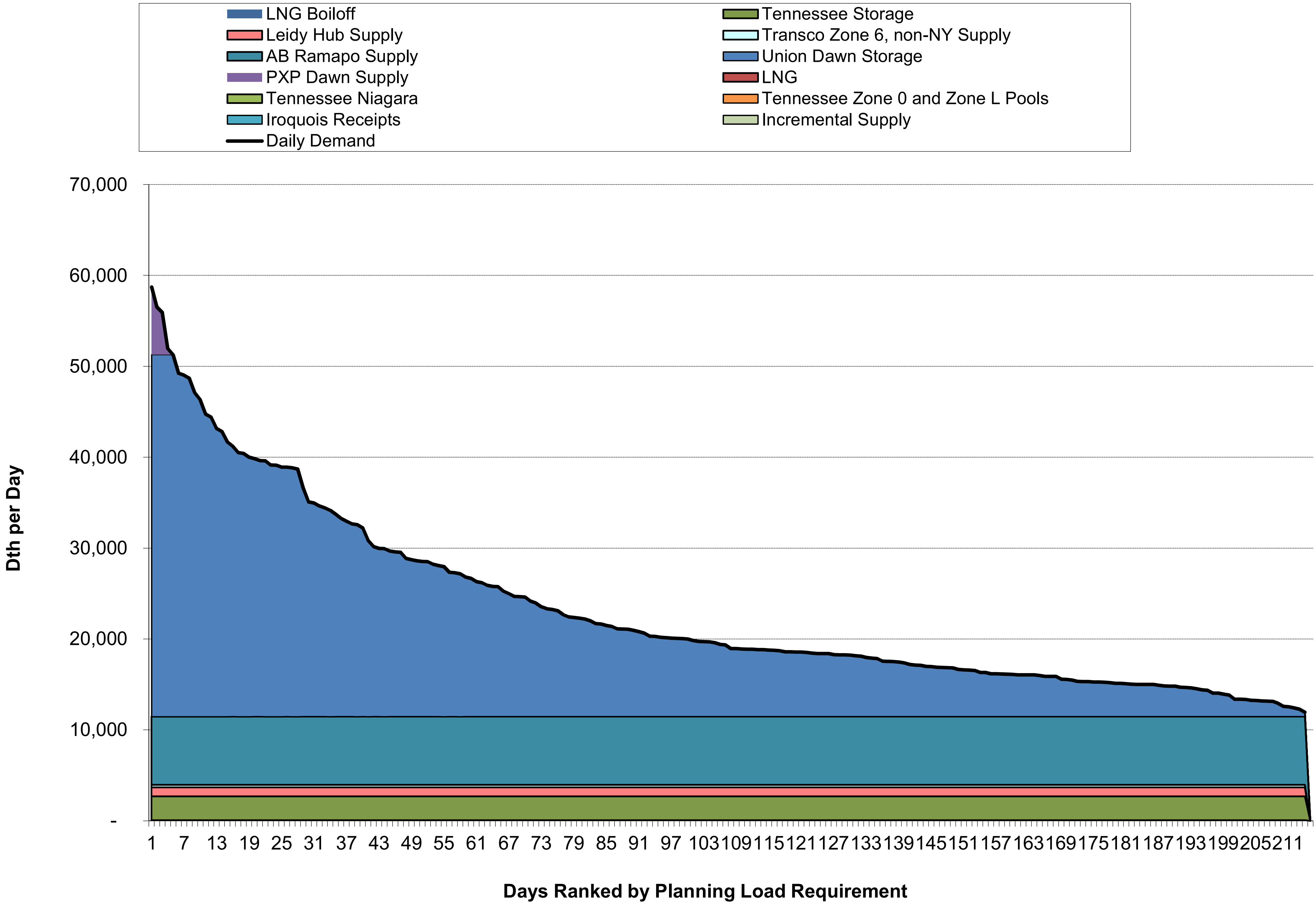
2020 Apr-Oct Normal Summer Load Duration Curve



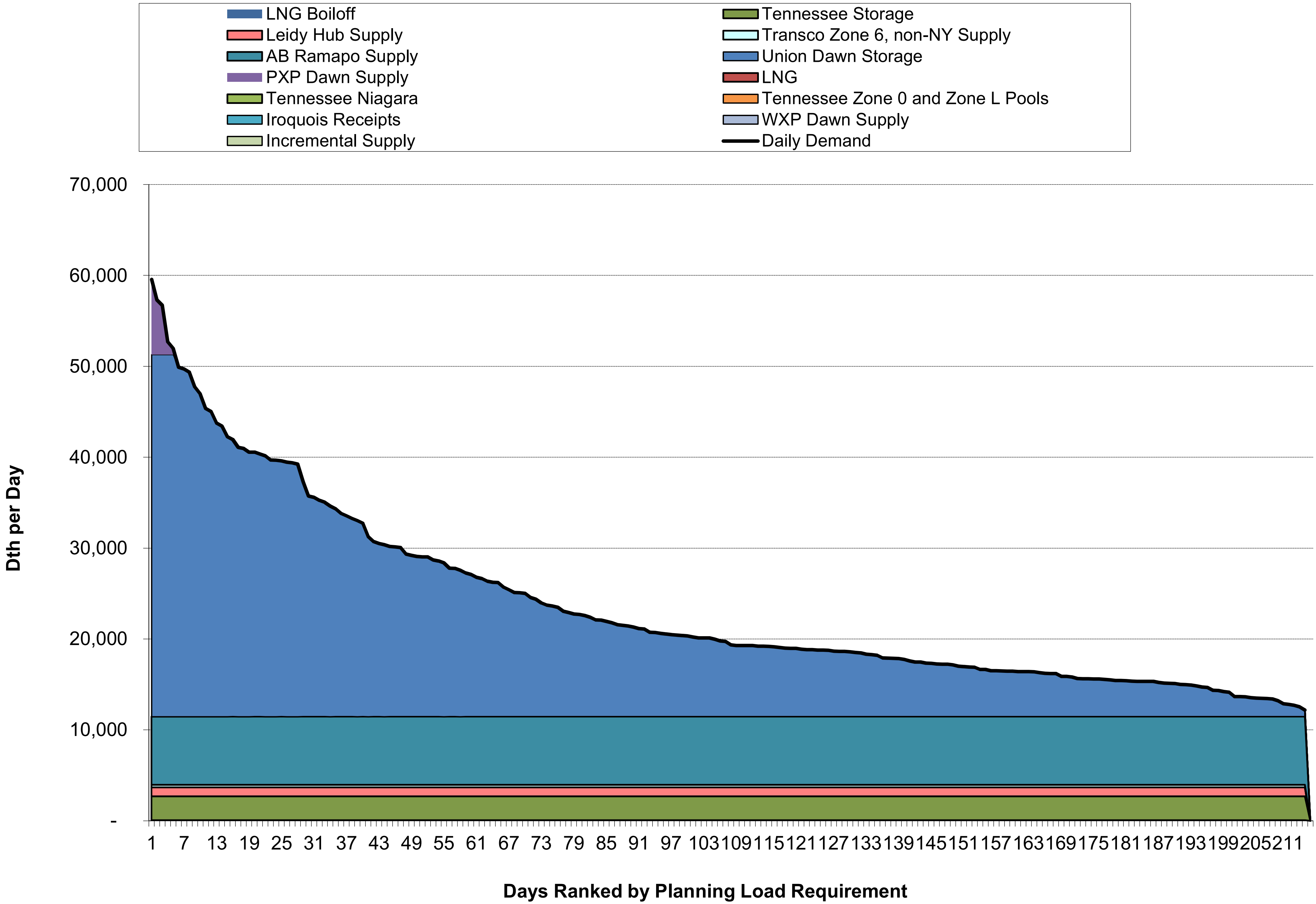
2021 Apr-Oct Normal Summer Load Duration Curve



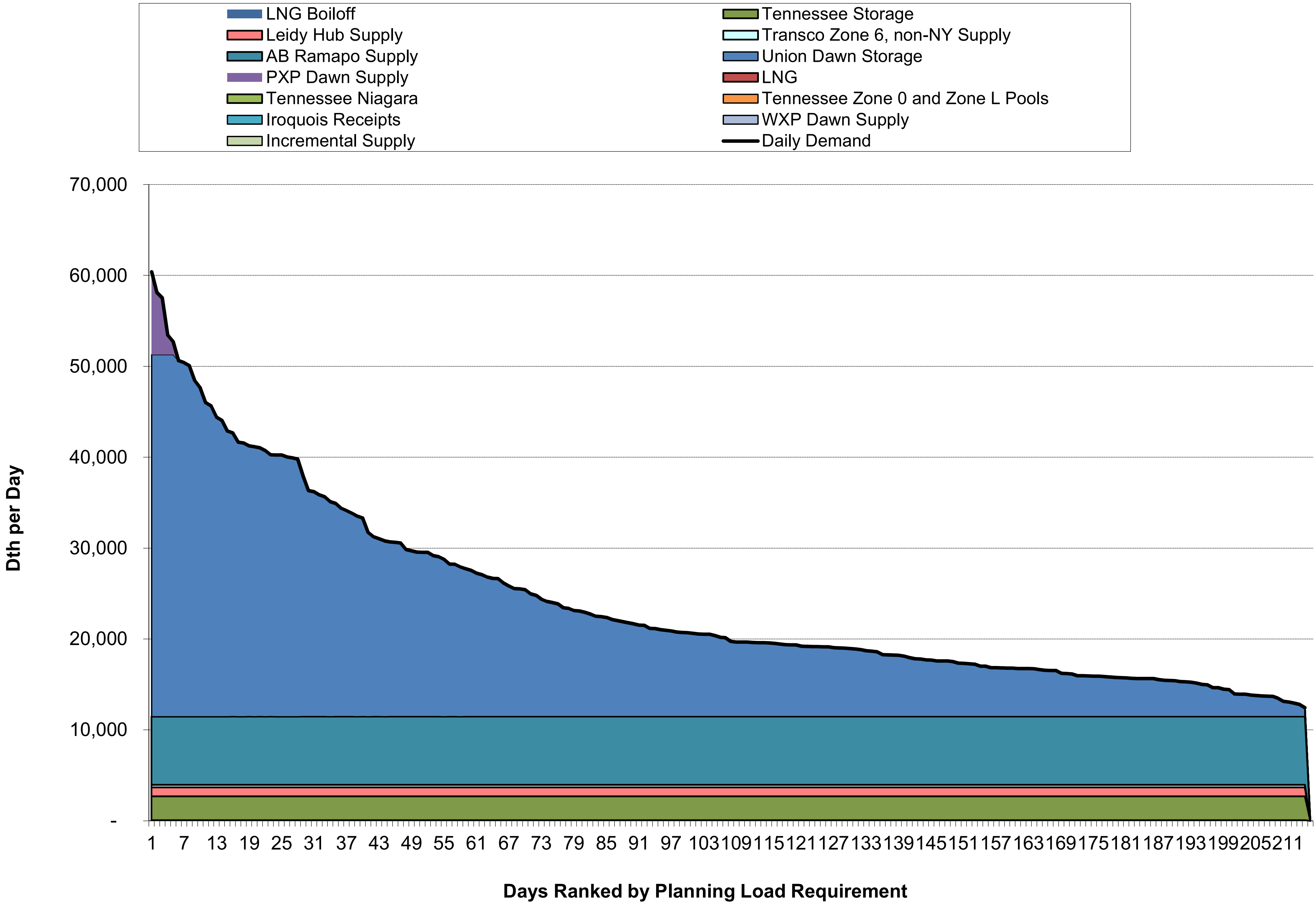
2022 Apr-Oct Normal Summer Load Duration Curve



2023 Apr-Oct Normal Summer Load Duration Curve



2024 Apr-Oct Normal Summer Load Duration Curve



REDACTED

2019-2020 Annual City Gate Cost, Delivered Volumes and Unit Cost - DESIGN YEAR

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost ($)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Tennessee FS-MA Storage Path	[redacted]	[redacted]	967,599	967,600	100%	[redacted]	[redacted]	[redacted]
2	Algonquin Receipts Pipeline Path	[redacted]	[redacted]	457,866	457,866	100%	[redacted]	[redacted]	[redacted]
3	Tennessee Niagara Pipeline Path	[redacted]	[redacted]	375,538	851,619	44%	[redacted]	[redacted]	[redacted]
4	Tennessee Long-Haul Pipeline Path	[redacted]	[redacted]	2,033,343	4,797,879	42%	[redacted]	[redacted]	[redacted]
5	Union Dawn Storage Path	[redacted]	[redacted]	9,420,640	14,589,854	65%	[redacted]	[redacted]	[redacted]
6	Iroquois Receipts Pipeline Path	[redacted]	[redacted]	982,351	2,366,351	42%	[redacted]	[redacted]	[redacted]
7	Lewiston LNG	[redacted]	[redacted]	125,000	125,000	100%	[redacted]	[redacted]	[redacted]
8	Incremental Delivered Supplies	[redacted]	[redacted]	1,935,427	N/A	N/A	[redacted]	[redacted]	[redacted]
	Total Portfolio Supplies	[redacted]	[redacted]	14,362,338	24,156,168	59%	[redacted]	[redacted]	[redacted]
	Total Supplies - Including Incremental	[redacted]	[redacted]	16,297,765	N/A	N/A	[redacted]	[redacted]	[redacted]

2020-2021 Annual City Gate Cost, Delivered Volumes and Unit Cost - DESIGN YEAR

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost ($)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Tennessee FS-MA Storage Path	[redacted]	[redacted]	964,956	964,956	100%	[redacted]	[redacted]	[redacted]
2	Algonquin Receipts Pipeline Path	[redacted]	[redacted]	456,615	456,615	100%	[redacted]	[redacted]	[redacted]
3	Tennessee Niagara Pipeline Path	[redacted]	[redacted]	351,351	849,292	41%	[redacted]	[redacted]	[redacted]
4	Tennessee Long-Haul Pipeline Path	[redacted]	[redacted]	1,945,548	4,784,770	41%	[redacted]	[redacted]	[redacted]
5	Atlantic Bridge Ramapo Pipeline Path	[redacted]	[redacted]	2,737,500	2,737,500	100%	[redacted]	[redacted]	[redacted]
6	Union Dawn Storage Path	[redacted]	[redacted]	6,690,809	14,549,991	46%	[redacted]	[redacted]	[redacted]
7	Iroquois Receipts Pipeline Path	[redacted]	[redacted]	975,890	2,359,889	41%	[redacted]	[redacted]	[redacted]
8	PXP Dawn Pipeline Path	[redacted]	[redacted]	1,519,514	3,637,225	42%	[redacted]	[redacted]	[redacted]
9	Lewiston LNG	[redacted]	[redacted]	125,000	125,000	100%	[redacted]	[redacted]	[redacted]
10	Incremental Delivered Supplies	[redacted]	[redacted]	766,402	N/A	N/A	[redacted]	[redacted]	[redacted]
	Total Portfolio Supplies	[redacted]	[redacted]	15,767,183	30,465,238	52%	[redacted]	[redacted]	[redacted]
	Total Supplies - Including Incremental	[redacted]	[redacted]	16,533,585	N/A	N/A	[redacted]	[redacted]	[redacted]

REDACTED

2021-2022 Annual City Gate Cost, Delivered Volumes and Unit Cost - DESIGN YEAR

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost ($)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Tennessee FS-MA Storage Path	[redacted]	[redacted]	964,956	964,956	100%	[redacted]	[redacted]	[redacted]
2	Algonquin Receipts Pipeline Path	[redacted]	[redacted]	456,615	456,615	100%	[redacted]	[redacted]	[redacted]
3	Tennessee Niagara Pipeline Path	[redacted]	[redacted]	351,351	849,292	41%	[redacted]	[redacted]	[redacted]
4	Tennessee Long-Haul Pipeline Path	[redacted]	[redacted]	1,948,568	4,784,770	41%	[redacted]	[redacted]	[redacted]
5	Atlantic Bridge Ramapo Pipeline Path	[redacted]	[redacted]	2,737,500	2,737,500	100%	[redacted]	[redacted]	[redacted]
6	Union Dawn Storage Path	[redacted]	[redacted]	6,859,839	14,549,991	47%	[redacted]	[redacted]	[redacted]
7	Iroquois Receipts Pipeline Path	[redacted]	[redacted]	975,890	2,359,889	41%	[redacted]	[redacted]	[redacted]
8	PXP Dawn Pipeline Path	[redacted]	[redacted]	1,522,734	3,637,225	42%	[redacted]	[redacted]	[redacted]
9	Lewiston LNG	[redacted]	[redacted]	125,000	125,000	100%	[redacted]	[redacted]	[redacted]
10	Incremental Delivered Supplies	[redacted]	[redacted]	843,227	N/A	N/A	[redacted]	[redacted]	[redacted]
	Total Portfolio Supplies	[redacted]	[redacted]	15,942,452	30,465,238	52%	[redacted]	[redacted]	[redacted]
	Total Supplies - Including Incremental	[redacted]	[redacted]	16,785,679	N/A	N/A	[redacted]	[redacted]	[redacted]

REDACTED

2022-2023 Annual City Gate Cost, Delivered Volumes and Unit Cost - DESIGN YEAR

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost ($)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Tennessee FS-MA Storage Path	[redacted]	[redacted]	964,956	964,956	100%	[redacted]	[redacted]	[redacted]
2	Algonquin Receipts Pipeline Path	[redacted]	[redacted]	456,615	456,615	100%	[redacted]	[redacted]	[redacted]
3	Tennessee Niagara Pipeline Path	[redacted]	[redacted]	346,595	849,292	41%	[redacted]	[redacted]	[redacted]
4	Tennessee Long-Haul Pipeline Path	[redacted]	[redacted]	1,889,642	4,784,770	39%	[redacted]	[redacted]	[redacted]
5	Atlantic Bridge Ramapo Pipeline Path	[redacted]	[redacted]	2,737,500	2,737,500	100%	[redacted]	[redacted]	[redacted]
6	Iroquois Receipts Pipeline Path	[redacted]	[redacted]	975,890	2,359,889	41%	[redacted]	[redacted]	[redacted]
7	Union Dawn Storage Path	[redacted]	[redacted]	6,100,442	14,549,991	42%	[redacted]	[redacted]	[redacted]
8	PXP Dawn Pipeline Path	[redacted]	[redacted]	1,526,549	3,637,225	42%	[redacted]	[redacted]	[redacted]
9	WXP Dawn Pipeline Path	[redacted]	[redacted]	1,494,980	3,637,225	41%	[redacted]	[redacted]	[redacted]
10	Lewiston LNG	[redacted]	[redacted]	125,000	125,000	100%	[redacted]	[redacted]	[redacted]
11	Incremental Delivered Supplies	[redacted]	[redacted]	413,665	N/A	N/A	[redacted]	[redacted]	[redacted]
	Total Portfolio Supplies	[redacted]	[redacted]	16,618,169	34,102,463	49%	[redacted]	[redacted]	[redacted]
	Total Supplies - Including Incremental	[redacted]	[redacted]	17,031,834	N/A	N/A	[redacted]	[redacted]	[redacted]

REDACTED

2023-2024 Annual City Gate Cost, Delivered Volumes and Unit Cost - DESIGN YEAR

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost ($)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Algonquin Receipts Pipeline Path	[redacted]	[redacted]	457,866	457,866	100%	[redacted]	[redacted]	[redacted]
2	Tennessee FS-MA Storage Path	[redacted]	[redacted]	967,599	967,600	100%	[redacted]	[redacted]	[redacted]
3	Tennessee Niagara Pipeline Path	[redacted]	[redacted]	349,024	851,619	41%	[redacted]	[redacted]	[redacted]
4	Tennessee Long-Haul Pipeline Path	[redacted]	[redacted]	1,910,528	4,797,879	40%	[redacted]	[redacted]	[redacted]
5	Atlantic Bridge Ramapo Pipeline Path	[redacted]	[redacted]	2,745,000	2,745,000	100%	[redacted]	[redacted]	[redacted]
6	Union Dawn Storage Path	[redacted]	[redacted]	6,271,880	14,589,854	43%	[redacted]	[redacted]	[redacted]
7	Iroquois Receipts Pipeline Path	[redacted]	[redacted]	982,351	2,366,351	42%	[redacted]	[redacted]	[redacted]
8	PXP Dawn Pipeline Path	[redacted]	[redacted]	1,540,490	3,647,190	42%	[redacted]	[redacted]	[redacted]
9	WXP Dawn Pipeline Path	[redacted]	[redacted]	1,506,008	3,647,190	41%	[redacted]	[redacted]	[redacted]
10	Lewiston LNG	[redacted]	[redacted]	125,000	125,000	100%	[redacted]	[redacted]	[redacted]
11	Incremental Delivered Supplies	[redacted]	[redacted]	428,061	N/A	N/A	[redacted]	[redacted]	[redacted]
	Total Portfolio Supplies	[redacted]	[redacted]	16,855,747	34,195,548	49%	[redacted]	[redacted]	[redacted]
	Total Supplies - Including Incremental	[redacted]	[redacted]	17,283,808	N/A	N/A	[redacted]	[redacted]	[redacted]

REDACTED

2019-2020 Annual City Gate Cost, Delivered Volumes and Unit Cost - NORMAL YEAR

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost ($)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Tennessee FS-MA Storage Path	[redacted]	[redacted]	967,599	967,600	100%	[redacted]	[redacted]	[redacted]
2	Algonquin Receipts Pipeline Path	[redacted]	[redacted]	457,866	457,866	100%	[redacted]	[redacted]	[redacted]
3	Tennessee Niagara Pipeline Path	[redacted]	[redacted]	375,538	851,619	44%	[redacted]	[redacted]	[redacted]
4	Tennessee Long-Haul Pipeline Path	[redacted]	[redacted]	2,033,343	4,797,879	42%	[redacted]	[redacted]	[redacted]
5	Union Dawn Storage Path	[redacted]	[redacted]	9,156,923	14,589,854	63%	[redacted]	[redacted]	[redacted]
6	Iroquois Receipts Pipeline Path	[redacted]	[redacted]	982,351	2,366,351	42%	[redacted]	[redacted]	[redacted]
7	Lewiston LNG	[redacted]	[redacted]	125,000	125,000	100%	[redacted]	[redacted]	[redacted]
8	Incremental Delivered Supplies	[redacted]	[redacted]	1,301,434	N/A	N/A	[redacted]	[redacted]	[redacted]
	Total Portfolio Supplies	[redacted]	[redacted]	14,098,621	24,156,168	58%	[redacted]	[redacted]	[redacted]
	Total Supplies - Including Incremental	[redacted]	[redacted]	15,400,055	N/A	N/A	[redacted]	[redacted]	[redacted]

REDACTED

2020-2021 Annual City Gate Cost, Delivered Volumes and Unit Cost - NORMAL YEAR

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost ($)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Tennessee FS-MA Storage Path	[redacted]	[redacted]	964,956	964,956	100%	[redacted]	[redacted]	[redacted]
2	Algonquin Receipts Pipeline Path	[redacted]	[redacted]	456,615	456,615	100%	[redacted]	[redacted]	[redacted]
3	Tennessee Niagara Pipeline Path	[redacted]	[redacted]	350,461	849,292	41%	[redacted]	[redacted]	[redacted]
4	Tennessee Long-Haul Pipeline Path	[redacted]	[redacted]	1,934,404	4,784,770	40%	[redacted]	[redacted]	[redacted]
5	Atlantic Bridge Ramapo Pipeline Path	[redacted]	[redacted]	2,737,500	2,737,500	100%	[redacted]	[redacted]	[redacted]
6	Iroquois Receipts Pipeline Path	[redacted]	[redacted]	975,890	2,359,889	41%	[redacted]	[redacted]	[redacted]
7	Union Dawn Storage Path	[redacted]	[redacted]	6,202,799	14,549,991	43%	[redacted]	[redacted]	[redacted]
8	PXP Dawn Pipeline Path	[redacted]	[redacted]	1,519,514	3,637,225	42%	[redacted]	[redacted]	[redacted]
9	Lewiston LNG	[redacted]	[redacted]	125,000	125,000	100%	[redacted]	[redacted]	[redacted]
10	Incremental Delivered Supplies	[redacted]	[redacted]	360,661	N/A	N/A	[redacted]	[redacted]	[redacted]
	Total Portfolio Supplies	[redacted]	[redacted]	15,267,138	30,465,238	50%	[redacted]	[redacted]	[redacted]
	Total Supplies - Including Incremental	[redacted]	[redacted]	15,627,799	N/A	N/A	[redacted]	[redacted]	[redacted]

REDACTED

2021-2022 Annual City Gate Cost, Delivered Volumes and Unit Cost - NORMAL YEAR

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost ($)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Tennessee FS-MA Storage Path	[redacted]	[redacted]	964,956	964,956	100%	[redacted]	[redacted]	[redacted]
2	Algonquin Receipts Pipeline Path	[redacted]	[redacted]	456,615	456,615	100%	[redacted]	[redacted]	[redacted]
3	Tennessee Niagara Pipeline Path	[redacted]	[redacted]	350,959	849,292	41%	[redacted]	[redacted]	[redacted]
4	Tennessee Long-Haul Pipeline Path	[redacted]	[redacted]	1,937,546	4,784,770	40%	[redacted]	[redacted]	[redacted]
5	Atlantic Bridge Ramapo Pipeline Path	[redacted]	[redacted]	2,737,500	2,737,500	100%	[redacted]	[redacted]	[redacted]
6	Union Dawn Storage Path	[redacted]	[redacted]	6,386,473	14,549,991	44%	[redacted]	[redacted]	[redacted]
7	Iroquois Receipts Pipeline Path	[redacted]	[redacted]	975,890	2,359,889	41%	[redacted]	[redacted]	[redacted]
8	PXP Dawn Pipeline Path	[redacted]	[redacted]	1,522,734	3,637,225	42%	[redacted]	[redacted]	[redacted]
9	Lewiston LNG	[redacted]	[redacted]	125,000	125,000	100%	[redacted]	[redacted]	[redacted]
10	Incremental Delivered Supplies	[redacted]	[redacted]	414,112	N/A	N/A	[redacted]	[redacted]	[redacted]
	Total Portfolio Supplies	[redacted]	[redacted]	15,457,672	30,465,238	51%	[redacted]	[redacted]	[redacted]
	Total Supplies - Including Incremental	[redacted]	[redacted]	15,871,784	N/A	N/A	[redacted]	[redacted]	[redacted]

REDACTED

2022-2023 Annual City Gate Cost, Delivered Volumes and Unit Cost - NORMAL YEAR

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost ($)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Tennessee FS-MA Storage Path	[redacted]	[redacted]	964,956	964,956	100%	[redacted]	[redacted]	[redacted]
2	Algonquin Receipts Pipeline Path	[redacted]	[redacted]	456,615	456,615	100%	[redacted]	[redacted]	[redacted]
3	Tennessee Niagara Pipeline Path	[redacted]	[redacted]	341,761	849,292	40%	[redacted]	[redacted]	[redacted]
4	Tennessee Long-Haul Pipeline Path	[redacted]	[redacted]	1,846,736	4,784,770	39%	[redacted]	[redacted]	[redacted]
5	Atlantic Bridge Ramapo Pipeline Path	[redacted]	[redacted]	2,737,500	2,737,500	100%	[redacted]	[redacted]	[redacted]
6	Iroquois Receipts Pipeline Path	[redacted]	[redacted]	975,890	2,359,889	41%	[redacted]	[redacted]	[redacted]
7	Union Dawn Storage Path	[redacted]	[redacted]	5,517,873	14,549,991	38%	[redacted]	[redacted]	[redacted]
8	PXP Dawn Pipeline Path	[redacted]	[redacted]	1,526,549	3,637,225	42%	[redacted]	[redacted]	[redacted]
9	WXP Dawn Pipeline Path	[redacted]	[redacted]	1,491,003	3,637,225	41%	[redacted]	[redacted]	[redacted]
10	Lewiston LNG	[redacted]	[redacted]	123,938	125,000	99%	[redacted]	[redacted]	[redacted]
11	Incremental Delivered Supplies	[redacted]	[redacted]	126,974	N/A	N/A	[redacted]	[redacted]	[redacted]
	Total Portfolio Supplies	[redacted]	[redacted]	15,982,820	34,102,463	47%	[redacted]	[redacted]	[redacted]
	Total Supplies - Including Incremental	[redacted]	[redacted]	16,109,794	N/A	N/A	[redacted]	[redacted]	[redacted]

REDACTED

2023-2024 Annual City Gate Cost, Delivered Volumes and Unit Cost - NORMAL YEAR

Total Unit Cost Rank	Supply Source	City-Gate Commodity Costs ($)	City-Gate Unit Commodity Cost ($/Dth)	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)	Demand Cost ($)	Total Cost ($)	City-Gate Total Unit Cost ($/Dth)
1	Algonquin Receipts Pipeline Path	[redacted]		457,866	457,866	100%	[redacted]		
2	Tennessee FS-MA Storage Path			967,599	967,600	100%			
3	Tennessee Niagara Pipeline Path			345,504	851,619	41%			
4	Tennessee Long-Haul Pipeline Path			1,872,034	4,797,879	39%			
5	Atlantic Bridge Ramapo Pipeline Path			2,745,000	2,745,000	100%			
6	Iroquois Receipts Pipeline Path			982,351	2,366,351	42%			
7	Union Dawn Storage Path			5,674,008	14,589,854	39%			
8	PXP Dawn Pipeline Path			1,540,490	3,647,190	42%			
9	WXP Dawn Pipeline Path			1,502,118	3,647,190	41%			
10	Lewiston LNG			124,120	125,000	99%			
11	Incremental Delivered Supplies			142,524	N/A	N/A			
	Total Portfolio Supplies			16,211,091	34,195,548	47%			
	Total Supplies - Including Incremental			16,353,615	N/A	N/A			

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 378
RATES AND CHARGES

Least Cost Energy Planning

Section 378:37

378:37 New Hampshire Energy Policy. – The general court declares that it shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost effective energy efficiency and other demand side resources; and to protect the safety and health of the citizens, the physical environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities.

Source. 1990, 226:1, eff. Jan. 1, 1991. 2014, 129:1, eff. Aug. 15, 2014.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 378
RATES AND CHARGES

Least Cost Energy Planning

Section 378:38

378:38 Submission of Plans to the Commission. –
Pursuant to the policy established under RSA 378:37, each electric and natural gas utility, under RSA 362:2, shall file a least cost integrated resource plan with the commission within 2 years of the commission's final order regarding the utility's prior plan, and in all cases within 5 years of the filing date of the prior plan. Each such plan shall include, but not be limited to, the following, as applicable:
I. A forecast of future demand for the utility's service area.
II. An assessment of demand-side energy management programs, including conservation, efficiency, and load management programs.
III. An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources.
IV. An assessment of distribution and transmission requirements, including an assessment of the benefits and costs of "smart grid" technologies, and the institution or extension of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages, including but not limited to, infrastructure automation and technologies.
V. An assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers.
VI. An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state.
VII. An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1.

Source. 1990, 226:1. 1994, 362:4, eff. June 8, 1994. 2014, 129:1, eff. Aug. 15, 2014. 2015, 89:3, eff. Aug. 4, 2015.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 378
RATES AND CHARGES

Least Cost Energy Planning

Section 378:38-a

378:38-a Waiver by Commission. – The commission, by order, may waive for good cause any requirement under RSA 378:38, upon written request by a utility.

Source. 1997, 298:14, eff. June 20, 1997. 2014, 129:1, eff. Aug. 15, 2014.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 378
RATES AND CHARGES

Least Cost Energy Planning

Section 378:39

378:39 Commission Evaluation of Plans. –
The commission shall review integrated least-cost resource plans in order to evaluate the consistency of each utility's plan with this subdivision, in an adjudicative proceeding. In deciding whether or not to approve the utility's plan, the commission shall consider potential environmental, economic, and health-related impacts of each proposed option. The commission is encouraged to consult with appropriate state and federal agencies, alternative and renewable fuel industries, and other organizations in evaluating such impacts. The commission's approval of a utility's plan shall not be deemed a pre-approval of any actions taken or proposed by the utility in implementing the plan. Where the commission determines the options have equivalent financial costs, equivalent reliability, and equivalent environmental, economic, and health-related impacts, the following order of energy policy priorities shall guide the commission's evaluation:
I. Energy efficiency and other demand-side management resources;
II. Renewable energy sources;
III. All other energy sources.

Source. 1990, 226:1. 1994, 362:5, eff. June 8, 1994. 2014, 129:1, eff. Aug. 15, 2014.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 378
RATES AND CHARGES

Least Cost Energy Planning

Section 378:40

378:40 Plans Required. – No rate change shall be approved or ordered with respect to any utility that does not have on file with the commission a plan that has been filed and approved in accordance with the provisions of RSA 378:38 and RSA 378:39. However, nothing contained in this subdivision shall prevent the commission from approving a change, otherwise permitted by statute or agreement, where the utility has made the required plan filing in compliance with RSA 378:38 and the process of review is proceeding in the ordinary course but has not been completed.

Source. 1994, 362:6, eff. June 8, 1994. 2014, 129:1, eff. Aug. 15, 2014.